COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and Approval of a Performance Based Ratemaking Mechanism.	)	**D.P.U. 17-05**

Direct Testimony of

Tim Woolf and Melissa Whited

On behalf of

Sunrun and The Energy Freedom Coalition of America, LLC

Regarding Performance-Based Regulation, the Monthly Minimum Reliability Contribution, Storage Pilots and Rate Design

April 28, 2017

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Exhibit SREF-TW/MW-6:	Woolf, T., M. Whited, P. Knight, T. Vitolo, K. Takahashi. 2016. *Show Me the Numbers: A Framework for Balanced Distributed Solar Policies.* Synapse Energy Economics for Consumers Union.

I. 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) from 2007 through 2011. 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 Commission, 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 SREF-TW/MW-2, 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 (DER), 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 DERs 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 DERs 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 SREF-TW/MW-3.

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

A. We are testifying on behalf of Sunrun and the Energy Freedom Coalition of America, LLC (EFCA). A non-profit corporation formed under the laws of the State of Delaware, EFCA is a trade association whose members include: Sun Solar Electric, LLC; Ecological Energy Systems, LLC; Go Solar LLC; SolarCity Corporation, a wholly-owned subsidiary of Tesla, Inc.; ZEP Solar Sunrun is the largest dedicated residential solar company in the United States. Sunrun designs, installs, finances, insures, monitors and maintains solar panels on a resident's home.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address Eversource's (the Company) proposed monthly minimum reliability contribution charge (MMRC) for new net metered customers, changes to rate design for existing net metered and non-net metered customers, and the Company's proposed Performance-Based Regulation Mechanism (PBRM) that establishes a rising revenue cap and is coupled with a commitment to spend $400 million on a set of grid modernization investments. We address each of these proposals in terms of their adherence to rate-making principles, and their implications for the development of DERs such as solar and storage technologies in Massachusetts. We note that the magnitude of the MMRC is influenced by the Company's revenue requirements (including the ROE), which are reflected in the Cost of Service Study. The revenue requirements and ROE are addressed in testimony provided by David Garrett on behalf of Sunrun and EFCA.

Q. Have you testified before the Department on rate design previously?

A. Yes. We testified on issues related to rate design in National Grid's rate case, D.P.U. 15-155.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your specific conclusions regarding the Company's MMRC proposal for new net metered customers.

A. Our conclusions regarding the Company's proposed MMRC are as follows:

1. The Company's rationale for proposing the MMRC is to address issues of "fairness" due to cost-shifting from net metered customers. Yet the Company has not demonstrated that a cost shift currently exists under the present rate structure or that the MMRC would equitably allocate costs, as it has not accounted for the costs and benefits associated with distributed generation.[1] Without such analysis, the Company has not demonstrated that the MMRC equitably allocates costs, as required by the Act.[2]

2. The proposed MMRC fails to adhere to the Department's rate design principles, particularly the principles of simplicity/understandability; continuity; and efficiency.

[1] In Response to LI-1-16, the Company states that "there is no discrete answer as to the specification and quantification of costs and benefits" associated with distributed generation.

[2] Chapter 75, "An Act Relative to Solar Energy

3. The proposed MMRC is inconsistent with the Commonwealth's energy policy goals to provide "for the continued support of solar power generation,"[3] as it would make new net metered customers significantly worse off without sufficient justification. For example, for an R-1 customer planning to install a 6 kW system in the Boston, the MMRC would reduce the customer's savings by more than $3,800 over the life of the system compared to the standard R-1 rate.[4]

Q. Please summarize your specific conclusions regarding the Company's proposal to increase the fixed charge for non-net metered R-1 and G-1 customers.

A. Increasing the fixed charge results in a reduction in the volumetric portion of a customer's bill,[5] which violates the Department's goal of efficiency. Increasing the fixed charge (and the consequent reduction of the volumetric charges) sends customers the signal that their energy usage matters less to their overall bill, 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. Fixed charges also do not provide actionable price signals, as customers cannot take any action in order to avoid or

[3] Chapter 75, "An Act Relative to Solar Energy."

[4] Distributed generation production assumptions based on the Company's analysis provided in Attachment-DPU-10-19. Assumes that the customer is otherwise paying the Company's proposed R-1 rate and that the solar system life is 25 years. Six kW system selected as the majority of distributed generation systems fall in the range of 5-10 kW, as reported in response to LI-1-17.

[5] Holding all else constant. If the revenue requirement increases, then the all rate components could potentially increase.

reduce them (other than disconnect from the electric grid). Further, the Company's proposed fixed charge increases would more than double[6] the fixed charge for some customers, violating the principle of gradualism.

Q. Please summarize your specific conclusions regarding the Company's proposal to eliminate time-varying rates, and eliminate inclining block rates for residential customers.

A. Distribution system costs are largely driven by local peak demands on the distribution system, rather than individual customers' peak demands. Accordingly, the majority of demand-related costs are allocated using class non-coincident peak demand, rather than customer non-coincident peak demand.[7] Both time-varying rates (such as time-of-use (TOU) rates) and inclining block rates provide superior price signals to flat rates, as TOU rates encourage customers to reduce energy consumption during peak hours, while inclining-block rates provide a stronger incentive to conserve energy. In other words, these rates provide more of an opportunity for customers to optimize their consumption patterns through conservation, load shifting, or investments in energy efficiency, distributed generation, and other demand-side resources. Eliminating these rate

[6] For example, customers on the South Shore/Cape Cod/Martha's Vineyard would see the customer charge increase from $3.73 to $8.00 per month.

[7] As explained by Mr. Heintz, class non-coincident peaks were used to allocate all the distribution demand costs with the exception of Line Transformers (Exhibit ES-ACOS-1, p. 9). In addition, the Company's confidential cost of service studies provided in Attachments DPU-1-3 and DPU-1-4 show that a significantly larger proportion of costs were allocated based on class non-coincident peak rather than on customer non-coincident peak..

structures would be a step backward in rate design, when the Company should be taking steps forward to help customers optimize their consumption and reduce system costs.

Q. Please summarize your conclusions regarding declining block rates.

A. We recommend that the Company's proposed declining block rates for G-1 customers, discussed below, be eliminated in order to strengthen incentives for customers to reduce their consumption through the adoption of energy efficiency or distributed generation.

Q. Please summarize your primary conclusions regarding performance based regulation and the Company's proposed Grid Modernization Base Commitment (GMBC).

A. Our primary conclusions on PBR and the GMBC are:

- Eversource's PBR proposal does not provide appropriate incentives to the Company to modernize the grid and empower customers to reduce overall system costs.
- Eversource has not proposed appropriate performance metrics and targets to guide its grid modernization activities or integrate DERs.
- Eversource has not sufficiently justified the pre-approval it seeks regarding the allocation of funds in the Grid Modernization Base Commitment.
- Eversource's PBR proposal is fundamentally flawed because it does not include a guaranteed minimum period before the next rate case (i.e., a "stay-out" provision).

Q. Please summarize your recommendations.

A. We offer the following recommendations:

1. The Department should reject the Company's proposed MMRC. The Department should articulate that if the Company wishes to propose an MMRC on the grounds of

customer equity and cost-shifting from distributed generation customers, it must first conduct a thorough analysis of any cost shifting and demonstrate that it is occurring. The cost shifting analysis should include all relevant costs and benefits of distributed generation resources, as well as a rate and bill impact analysis. We describe the appropriate means of conducting such analysis in our report "Show Me the Numbers: A Framework for Balanced Distributed Solar Policies" attached as Exhibit SREF-TW/MW-6.[8]

2. The Department should not increase the current customer charges by any more than the percentage increases that are applied to the energy charges to attain the class revenue requirements allowed by the Department in this docket.

3. The Department should direct Eversource to maintain and improve voluntary distribution TOU rates for all customers, particularly for customers with electric vehicles. In order to inform the development of electric vehicle rates, we recommend that the Department resume its investigation in D.P.U. 13-182, or open a new docket to explore electric vehicle rate design issues. In addition, the Department should revisit the issue of TOU distribution rates more generally to ensure that customers who can shift load to reduce peak distribution circuit demand are provided the price signals to do so.

[8] Exhibit SREF-TW/MW-6. Tim Woolf et al., "Show Me the Numbers: A Framework for Balanced Distributed Solar Policies" (Synapse Energy Economics, prepared for Consumers Union, November 10, 2016), http://www.synapse-energy.com/project/show-me-numbers-framework-balanced-distributed-solar-policies.

4. The Department should maintain the inclining block rate structure for all residential customers until it is replaced by a rate structure that provides more efficient price signals.

5. The Department should reject the Company's PBR proposal as presented. If the Department approves some sort of PBR structure for Eversource, we recommend that the Department:

    a) require a stay-out period before Eversource may file its next rate case; and

    b) reject Eversource's request for pre-approval of $400 million of capital investment in the GMBC until and unless the Company justifies the investments through a comprehensive business-case analysis demonstrating the investments are a part of a plan for least-cost provision of service.

6. Regardless of whether Eversource operates under a PBR regime, we recommend that the Department:

    a) establish an expectation that Eversource will build on any energy storage pilots undertaken over the next several years to further identify and deploy utility-sited and customer-sited storage in cost-effective solutions;

    b) establish a Department mandate for transparency, coordination, and data sharing with DER technology providers and manufacturers that would enable the deployment of DER technology based on system needs;

    c) establish explicit metrics and targets to guide Eversource's activities for grid modernization, including metrics and targets corresponding to any portions of the GMBC that the Department believes will provide net customer value, along with metrics for enabling and advancing third-party DER provider investment and deployment; and

d) consider explicit metrics and incentives to encourage utilities to utilize DERs to cost-effectively avoid traditional capital investments. These could include financial rewards for especially successful adoption of DERs, and penalties in situations where the Company did not adequately evaluate or implement DER alternatives.

III. MMRC BACKGROUND

Q. Please describe the 2016 Act Relative to Solar Energy.

A. In 2016, the legislature of the Commonwealth of Massachusetts established An Act Relative to Solar Energy ("Act"). St. 2016, c. 75. The purpose of this act was "to provide forthwith for the continued support of solar power generation and a transition to a stable and equitable solar market at a reasonable cost to ratepayers."

Among the Act's provisions is that the DPU *may* approve an MMRC that: (1) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (2) does not excessively burden ratepayers; (3) does not unreasonably inhibit the development of Net Metering Facilities; and (4) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. St. 2016, c. 75, § 9; G.L. c. 164, §139(j).

IV. EVERSOURCE'S MMRC PROPOSAL

Q. Please describe Eversource's MMRC proposal.

A. Eversource's proposed MMRC would impose a new rate structure on net metering customers that are interconnected to the Company's system on or after January 1, 2018 for residential customers, or on or after January 1, 2019 for general service customers.[9] The MMRC would vary by class, but would consist of a higher customer charge, a demand charge, and a reduced energy (or volumetric) charge.

Q. Would this rate structure represent a significant change for customers?

A. Yes. For the residential and small commercial (G-1) classes, many customers would be subject to a demand charge for the first time. Moreover, the customer charge would be significantly increased. For R-1 customers the customer charge would increase by 61% from current rates, while G-1 non-demand customers would see the customer charge more than double.

Table 1 below shows how rates would change for new net metered customers in the R-1 and G-1 (non-demand) classes in the Boston area.[10]

[9] Exhibit ES-RDP-1, p. 91.

[10] Current rates based on "2017 Summary of Eastern Massachusetts Electric Rates for Greater Boston Service Area", available at https://www.eversource.com/Content/docs/default-source/rates-tariffs/ema-greater-boston-rates.pdf?sfvrsn=10. Proposed rates as described in Exhibit ES-RDP-6, Schedule RDP-1 (East).

Table 1. Proposed MMRC compared with Current Rates

		Current Rates	MMRC	Change
R-1	Customer Charge	$6.43	$10.38	61%
	Demand Charge	--	$2.12	NEW
	Distribution Charge	$0.056	$0.031	-45%
G-1	Customer Charge	$8.14	$19.36	138%
	Demand Charge	--	$5.16	NEW
	Distribution Charge	$0.072	$0.019	-74%

Q. What types of costs are included in the MMRC?

A. The costs included in the MMRC are classified as demand-related costs. These costs include poles, conduit, conductor, and service transformers.[11]

Q. What is the Company's rationale for proposing the MMRC?

A. The Company alleges that net metering "results in cost shifting within the distribution component of service, and in other components of service."[12] In response to the Act, the Company is proposing an MMRC that would apply to new net metering customers in order to alleviate alleged cost-shifting among customers.

[11] Exhibit ES-RDP-1, p. 94.

[12] Exhibit ES-RDP-1, p. 95.

Q. Is the Company also proposing the MMRC in order to ensure that the Company recovers adequate revenues to ensure the reliability, proper maintenance, and safety of the electric distribution system?

A. No. As acknowledged by the Company, revenue decoupling allows the Company to recover its allowed revenues and makes the Company "whole."[13] Thus the reliability of the system is not jeopardized by net metering's impacts on utility revenues, as the utility's ability to recover its allowed revenues is not in question. Instead, the Company is proposing the MMRC only to address the alleged cost-shifting.

V. THE MMRC IS NOT JUSTIFIED ON THE GROUNDS OF COST-SHIFTING

Q. Has Eversource demonstrated that there is a need for the MMRC because of cost-shifting?

A. No. While the Company claims that cost-shifting is occurring, it refers only to the displaced revenues[14] as evidence of the alleged cost shift and fails to account for the benefits provided by net metered customers. The benefits provided by net metering customers work to offset the displaced revenues, thereby mitigating cost-shifting. For example, in our recent analysis of the value of solar in Washington, DC, we found that cost-shifting was largely mitigated by the benefits provided by distributed solar.[15]

[13] Exhibit ES-RDP-1, p. 19.

[14] Exhibit ES-RDP-1, p. 96.

[15] Our analysis found that utility system benefits amounted to more than $0.13/kwh, resulting in an impact of $0.02 per month for the average non-net metered residential customer. *See:* Melissa Whited et al., "Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting" (Synapse Energy

Q. What are displaced revenues?

A. Generation from customers' net metered systems reduces the Company's electricity sales. This reduction in sales results in "displaced revenues" – revenues that would have been collected from the net metering customers were it not for their self-generation.

Q. Are these displaced revenues a cost?

A. Displaced revenues are not a cost, as they do not increase the Company's revenue requirement. However, they can affect the allocation of existing costs among customers. When displaced 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 embedded costs from the net metered customers to the other customers.

Q. Do displaced revenues indicate the existence of a cost shift?

A. No, displaced revenues alone cannot be used as an indicator of a cost-shift. While the recovery of displaced revenues results in upward pressure on rates, the benefits provided by distributed generation exert a countervailing effect by reducing the costs to all customers, thereby offsetting some or all of the impact created by the recovery of displaced revenues. Both the upward pressure of displaced revenues and the downward pressure of distributed generation benefits must be accounted for in order to determine any cost shift.

Economics, prepared for the Office of the People's Counsel for the District of Columbia, April 12, 2017), http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.

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

A. Distributed generation can provide a wide range of benefits to the entire electric system by reducing distribution costs, transmission costs, purchases from wholesale electricity markets, and environmental compliance costs. These benefits put downward pressure on electricity rates and will reduce or eliminate any cost-shifting that might occur as a result of distributed generation.[16]

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.[17]

Q. How do you recommend that concerns about cost-shifting be addressed?

A. In order to promote customer equity and fairness, it is essential to fully understand whether any cost-shifting is occurring, and to use analyses that account for both the costs

[16] See, for example, Whited, et al. Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting. Synapse Energy Economics, April 2017. Available at http://www.synapse-energy.com/project/distributed-generation-potential-value-and-policies-washington-dc.

[17] *Id.*

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. Has the Company quantified the costs and benefits associated with DG?

A. No. While the Company states that this issue is "front-and-center in the industry today," it claims that "there is no discrete answer as to the specification or quantification of costs and benefits."[18]

Q. Are the costs and benefits of distributed generation too uncertain to quantify?

A. While there is always some uncertainty regarding costs and benefits that occur in the future, this is true for any resource, whether it is energy efficiency, a power plant, or distributed generation. Instead of attributing a zero value to a resource, Massachusetts has developed methods for estimating the avoided costs associated with demand resources. For example, the Department's Energy Efficiency Guidelines require that program administrators calculate the benefits associated with avoided generation capacity, avoided energy, avoided transmission, avoided distribution, Demand Reduction Induced Price

[18] Response to LI-1-16.

Effects (DRIPE), and reduced customer arrearages and reduced service terminations and reconnections.[19]

Q. Does distributed solar generation provide similar benefits to the utility system?

A. The benefits associated with solar generation are unique to the resource's load profile, but are categorically similar to those provided by energy efficiency. Numerous jurisdictions have undertaken studies to estimate the value of distributed solar generation. For example, we recently co-authored a value of solar study on behalf of the Office of the People's Counsel for the District of Columbia titled *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting.*[20]

Q. Has the Department previously commented on how cost shifting should be analyzed for ratemaking purposes?

A. Yes. The Department has clearly stated that allegations of cost-shifting should be supported by data and analysis beyond simply looking at displaced revenues. In its recent order in D.P.U. 15-155, the Department stated that it was "not persuaded that a cost-shift from DG customers to non-DG customers, in fact, exists," because National Grid had not quantified the costs or system benefits associated with DG customers. In particular, the Department noted that "other than quantifying net metering credits and citing to current rate design, the Company did not substantiate its cost-shift assumption with reasonable analysis

[19] Energy Efficiency Guidelines, January 31, 2013, Order Approving Revised Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II.

[20] Whited, et al. Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting. Synapse Energy Economics, April 2017. Available at http://www.synapse-energy.com/project/distributed-generation-potential-value-and-policies-washington-dc

and quantitative record evidence."[21] Partly for this reason, the Department declined to approve National Grid's rate design proposal.

Q. If it were demonstrated that cost shifting is occurring, would the Company's MMRC be an appropriate mechanism for mitigating it?

A. No. The Company's proposed MMRC is fundamentally flawed from a rate design perspective, as discussed in the following section.

VI. THE PROPOSED MMRC VIOLATES THE DEPARTMENT'S RATE DESIGN PRINCIPLES

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

A. As summarized in its January "Order Outlining Scope of Monthly Minimum Reliability Contribution Proposal," the Department's goals of designing utility rates are to "achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability."[22]

[21] D.P.U. 15-155, Order, 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, September 30, 2016.

[22] Massachusetts DPU, Order in *Investigation of the Department of Public Utilities, on its own Motion, Commencing a Rulemaking Pursuant to G. L. c. 164, §§ 138 and 139; G. L. c. 30A, § 2; and 220 C.M.R. et seq.; and Executive Order 562 to Amend 220 C.M.R. §18.00 et seq.*, D.P.U. 16-64-E, January 13, 2017, p. 3.

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,[23] which most states draw from in designing rates. These principles are reproduced in Exhibit SREF-TW/MW-4.

Q. Is the proposed MMRC consistent with these rate design principles?

A. No. The Company's MMRC is inconsistent with the principles of efficiency, simplicity, continuity, and fairness. While the MMRC is not at odds with the principle of corporate earnings stability, concern regarding revenue recovery is not an issue due to revenue decoupling (as discussed above).

<u>Efficient Price Signals</u>

Q. How is the goal of efficiency defined?

A. With respect to efficiency, the Department has stated 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."[24]

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

[24] 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"], pp. 423-424.

- 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."[25]

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

Q. How can the goal of efficiency be achieved?

A. To encourage customers to minimize system costs and reduce wasteful usage, customers should be provided with efficient price signals.

Q. How can price signals help customers minimize distribution system costs?

A. Rate design provides customers with price signals that can help encourage customers to optimize their electricity consumption patterns and reduce demand on the system when it is stressed. For example, a customer may choose to conserve energy or invest in distributed energy resources, such as energy efficiency, demand response, distributed generation, electricity storage, and more. By reducing demand on the system, particularly during peak periods, future costs related to distribution system upgrades can be reduced.

Q. Please explain why the proposed MMRC fails to provide an efficient price signal.

A. The Company's proposed MMRC increases the fixed customer charge and imposes a demand charge on customers. The customer charge and demand charge are difficult or

[25] DPU 09-39, pp. 401-402.

impossible for customers to avoid, and both of these charges reduce the volumetric rate. A lower volumetric rate sends customers the price signal that their usage does not affect distribution system costs, and provides less of an incentive for customers to reduce their energy consumption. In fact, a lower volumetric rate may even induce customers to increase their energy consumption, which is particularly problematic if such consumption coincides with system peak periods. Greater usage of the system will cause the utility to invest in additional capacity, and may cause equipment to wear out faster, increasing long-run system costs.

Q. Why does a demand charge not provide an efficient price signal?

A. While a demand charge provides more of a price signal than a fixed charge, it is flawed in several fundamental ways. First, the Company's proposed demand charge does little to encourage customers to reduce consumption when it matters most – during peak demand hours. Because the utility system is sized to meet the system's coincident peak demands,[26] it is not the individual residential customer's peak demand that drives

[26] The system coincident peak demands may vary at different levels of the system. For example, a distribution system feeder may experience its peak demand at a different time than the bulk transmission system.

additional system costs,[27] but the timing of that demand and its coincidence with other demands on the system.[28]

Second, the price signal to reduce demand is concentrated into a single hour of the month – the hour of the customer's individual maximum demand. During other hours, the price signal is limited, since reducing demand below the customer's monthly peak will have no financial benefit for the customer. Thus the price signal sent by the demand charge is that reducing electricity consumption outside of the customer's single peak hour is of little value to the system. A more efficient price signal would encourage customers to reduce energy consumption in each and every hour that the system is stressed, not just for the single hour that an individual customer reaches his or her maximum demand.

Finally, the demand charge reduces the distribution rate ($/kWh), thereby reducing incentives for energy efficiency. As shown in Table 1 above, the MMRC would lower the distribution rate by 45% for R-1 customers and 74% for G-1 customers in Eastern Massachusetts. It is well-established that residential customers exhibit negative elasticity of demand. This means that, holding all else equal, a reduction in the price of electricity

[27] A small non-coincident demand charge may be appropriate for large commercial and industrial customers, where certain components of the system must be sized to meet that individual customers, where an increase in the customer's demand would require an equipment upgrade. But most utility system costs are not driven by an individual residential customer's non-coincident maximum demand – instead, they are driven by coincident demands during peak hours.

[28] *See, for example:* Jim Lazar, "Use Great Caution in Design of Residential Demand Charges," *Natural Gas & Electricity*, February 2016, available at https://www.raponline.org/document/download/id/7844, p. 19: "NCP [Non-Coincident Peak] demand is not relevant to any system design or investment criteria above the final line transformer, and only there is the transformer serves just a single customer."

will lead to an increase in electricity consumption, and incentives for energy efficiency and conservation will be reduced.

Simplicity

Q. Does the MMRC comport with the principle of simplicity?

A. No. 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."

Demand charges represent a much more complex rate design than residential customers and many small commercial customers are accustomed to. Surveys and focus groups have found that the concept of demand charges are not well-understood and frequently raise concerns from customers.[29] Not only are demand charges conceptually new, customers generally lack the tools needed to manage their demand, and Eversource's proposal contains no plans to provide customers with such tools. Without investing in automating technology, residential customers have little ability to monitor and quickly

[29] Recent surveys indicate that approximately 50% of residential customers do not understand the terms "kW" and "kWh". *See:* LeBlanc, Bill. "Do Customers Understand Their Power Bill? Do They Care? What Utilities Need to Know." Blog summary of E Source Survey. January 21, 2016. *https://www.esource.com/email/ENEWS/2016/Billing* . Further, focus groups in Ontario found that the concept of maximum use during peak hours "is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU." Customers also expressed concerns regarding fairness, specifically that "that small lapses in their conservation efforts will mean they will have to pay a high price". *See:* Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups Final Report, October 9, 2013("Gandalf Report"), available at : http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0410/Appendix%20B%20-%20Gandalf%20Distribution%20Focus%20Groups.pdf at p. 9.

adjust their demand levels.[30] Further, where residential demand charges have been implemented, enrollment tends to be very low, indicating low levels of customer acceptance.

Q. What percentage of customers have enrolled in demand-based rates?

A. Of the 24 other examples of demand charges that have been applied to residential customers in the US on an opt-in basis, most have enrollment below 1%,[31] despite existing for multiple years and customer marketing efforts.[32] The exceptions are Arizona Public Service (APS) with enrollment of 11% and Black Hills Power with enrollment of 8%.[33] Yet even at APS, customers prefer the energy-only time-of-use rate to the demand charge rate by a margin of four to one,[34] and each year approximately 20% to 25% of customers on the demand charge rate opt to leave the rate.[35]

Q. Have any investor-owned utilities made demand-based rates mandatory for residential customers?

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[30] For example, a widely held concern of participants in focus groups in Ontario regarding demand charges is that they do not have the tools to manage their demand. *See:* Gandalf Report, at pp. 6, 11.

[31] Rocky Mountain Institute, *A Review of Alternative Rate Designs*, May 2016 ("RMI Review"), at p. 72.

[32] For example, Alabama Power Co. has enrollment levels far below 1%, despite marketing efforts and having had the program in place for more than four years.

[33] RMI Review, at p. 72.

[34] Eddie Easterling, "EUCI Residential Demand Charge Summit," May 14, 2015.

[35] Direct Testimony of James A. Heidell, on behalf of EFCA, Docket No. E-0I345A-16-0036 & E-01345A-I6-0123, February 3, 2017, pages 41-42.

A. No. In fact, demand charges have been routinely rejected for mandatory application to residential customers. Several recent examples include California, Arizona, Nevada, and Oklahoma.

In California, the Commission explicitly rejected demand charges as a component of a net metering successor tariff. The Commission's rationale was that "demand charges can be complex and hard for residential customers to understand. Since the vast majority of NEM customers are residential customers, it is reasonable to consider the NEM successor tariff in light of the needs of residential customers. From that perspective, the NEM successor tariff should not incorporate a demand charge…"[36]

In Oklahoma, the Commission rejected the proposed demand charge and implemented two requirements that the utility must fulfill if it wishes to propose a demand charge in the future:

1) The utility must first conduct a study and pilot program on demand charges to evaluate customer acceptance, understanding, and ability to respond to a demand charge; and

2) For any demand charge for customers with distributed generation, the utility must "include as part of its case cost effectiveness tests, such as those performed for the

[36] California Public Utilities Commission, Decision 16-01-044, Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking 14-07-002, January 28, 2016, p. 75.

> company's demand programs, and make available to the parties detailed cost and benefit data."[37]

In Arizona, the Commission recognized that there was significant "public distrust or antipathy to the [demand charge] proposal" and stated that "In order for customers to understand how demand charges work and how they can manage their energy consumption to save money, or at least not incur a bill increase, requires education and tools available to monitor their load," which have not "been made available."[38] Nevada's rationale for declining to implement a mandatory demand charge for net metered customers, similarly hinged on customer education needs and uncertainty regarding customer acceptance.[39]

Despite this, Eversource proposes to make demand charges mandatory for new residential net metering customers.

<u>Continuity</u>

Q. Is the MMRC consistent with the principle of continuity?

A. No. 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

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[37] Oklahoma Corporation Commission, Final Order, Cause No. PUD 201500273, March 20, 2017, page 13.

[38] Arizona Corporation Commission, Decision No. 75697, Docket No. E-04204A-15-0142, August 8, 2016, at 65.

[39] Nevada Public Utilities Commission, Docket No. 15-07041 and Docket No. 15-07042, February 12, 2016, p. 147.

change in structure."[40] Professor Bonbright defines this goal as the "stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."[41]

In contrast to a gradual approach, the MMRC would significantly alter the rate structure for many net metered customers, particularly residential and non-demand small commercial customers. In addition to introducing an entirely new charge in the form of a demand charge, the MMRC would more than double or even triple the fixed charge for many customers compared with current rates.

As shown in the table below, proposed customer charge increase would range from 51% to 178% for residential customers, and 138% to 319% for certain small commercial customers. Such a massive increase cannot be described as "gradual," and clearly violates the principle of continuity.

Table 2. Customer Charge under MMRC Compared to Current Rates

		Current Customer Charge	MMRC Customer Charge	Change
R-1	South Shore	$3.73	$10.38	178%
	Cape Cod/Martha's Vineyard	$3.73	$10.38	178%
	Cambridge	$6.87	$10.38	51%
	Greater Boston	$6.43	$10.38	61%
	WMECO	$6.00	$14.55	143%
G-1 (Non-	Cambridge	$4.62	$19.36	319%

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

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

Demand)	Greater Boston	$8.14	$19.36	138%

<u>Fairness</u>

Q. Does the MMRC promote fairness between rate classes?

A. The Department explains that fairness means that "no class of customers should pay more than the costs of serving that class."[42] Eversource asserts that the MMRC promotes fairness by reducing the potential for costs to be shifted to other rate classes.[43] However, as described above, 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.[44] These reduced costs then translate into lower revenue requirements for distribution utilities and lower costs of generation for all customers.

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.

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

[43] Exhibit ES-RDP-1, p. 43.

[44] 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

Q. Please summarize your conclusions regarding the MMRC and the Department's rate design principles.

A. The proposed MMRC is in direct contravention to the Department's goals of efficiency, simplicity, and continuity. The MMRC's proposed demand charge and higher customer charge will fail to achieve the goals of equity and efficiency, and in fact would reduce customer control, distort price signals, and lead to significant customer confusion. Further, the MMRC's mandatory demand charge for residential customers would create a dangerous precedent, and would certainly lead to future proposals aimed at expanding the breadth and magnitude of residential demand charges.

VII. THE MMRC CONFLICTS WITH STATE ENERGY POLICIES TO SUPPORT SOLAR DEVELOPMENT

Q. Please describe the Commonwealth's energy policy goals regarding solar as articulated in the Act.

A. As stated in the Act Relative to Solar Energy, the Commonwealth endeavors to provide "continued support of solar power generation and a transition to a stable and equitable solar market at a reasonable cost to ratepayers."

Q. How does the Commonwealth intend to achieve this goal?

A. Historically, the Commonwealth has sought to support distributed solar through a combination of programs, including net metering and solar renewable energy certificates (SRECs). As solar has grown, the Commonwealth has seen fit to amend these programs. For example, SRECs are being replaced by a successor program, referred to as the Solar Massachusetts Renewable Target (SMART) Program, as provided for in the Act. Net metering has also been modified to reduce the value of excess generation credits for non-cap-exempt installations.[45]

Q. How would the MMRC interface with the other provisions of the Act?

A. The MMRC, as proposed by Eversource, would have two impacts on the other provisions of the Act. First, the MMRC would reduce further the value of net metering credits for new solar customers. Second, the MMRC could work at odds with the requirement that the Department of Energy Resources develop a statewide solar incentive program "to encourage the continued development of solar renewable energy generating sources" by electricity customers in Massachusetts.

Q. Are these impacts consistent with the goals of the Act?

A. No. The intent of the Act is not to undermine solar development and other Commonwealth programs that support solar; rather, the Act's stated intent is to provide stable support for continued solar development.

VIII. THE COMPANY'S OTHER RATE DESIGN PROPOSALS CONFLICT WITH THE DEPARTMENT'S RATE DESIGN PRINCIPLES

Q. Please describe the Company's other rate design proposals that you wish to address.

A. The Company is proposing three rate design changes that would impact non-net metering customers as well as current net metering customers:

[45] The Market Net Metering credit is set to 60 percent of the retail rate, per 220 CMR 18.04(3).

1) Elimination of all optional time-of-use rates[46]

2) Elimination of inclining block rates[47]

3) Higher customer charges for residential and small commercial customers[48]

In addition to increasing the customer charge, the Company proposes to maintain declining rates for certain G-1 customers.[49]

Q. Why does the Company propose to eliminate optional time-of-use rates?

A. The Company states that, "from a distribution cost basis, volumetric time-of-use rates are not appropriate" because distribution system costs "are primarily demand related."[50]

Q. Do you agree that time-of-use rates are not appropriate for demand-related costs?

A. No. Demand is simply the measure of electricity use during a specific time period. Distribution costs are largely driven by costs during peak hours, i.e., during specific time periods. To reduce future distribution system investments, it is therefore reasonable to provide a price signal that encourage customers to reduce demand during the time periods when peak demand on the distribution system is likely to occur. Time-varying rates (such as time-of-use rates) can help to provide such a price signal. Further, providing price

[46] Exhibit ES-RDP-1, p. 16.

[47] Exhibit ES-RDP-1, page 45.

[48] Exhibit ES-RDP-1, page 42 and Exhibit ES-RDP-4.

[49] Exhibit ES-RDP-1, page 14.

[50] Exhibit ES-RDP-1, page 16.

signals to reduce demand during peak hours will become even more important as electric vehicles become more common.

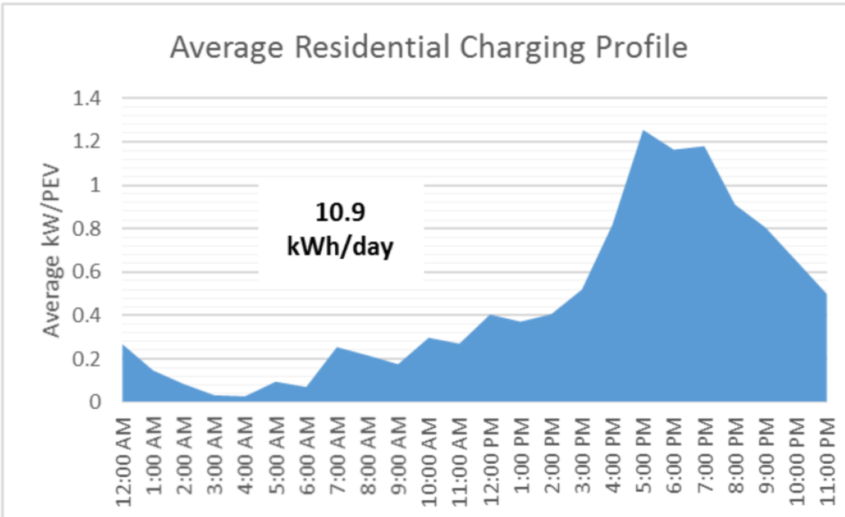
Q. Why will electric vehicles make it even more important to provide a time-based price signal for distribution rates?

A. Electric vehicles use energy intensively. For example, a standard Level 2 EV charger can easily double the load of an entire household.[51] With time-invariant rates, residential customers often charge their EVs in the late afternoon and evening hours.[52] For example, the figure below shows an analysis by Avista Utilities in Washington state illustrating that most residential charging occurs between the hours of 4 pm and 10 pm with hourly load exceeding 1 kW per vehicle during the early evening hours.

[51] Nexant. 2014. "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.

[52] See, for example, SDG&E Chart 9, in SCE, PG&E, SDG&E, "5th Joint IOU Electric Vehicle Load Research Report," 13-11-007, *Load Research Report Compliance Filing of Southern California Edison Company (U 338-E), on Behalf of Itself, Pacific Gas and Electric Company (U 39e), and San Diego Gas & Electric Company (U 902-M), Pursuant to Ordering Paragraph 2 of D.16-06-011*, December 30, 2016, 16-06–011.

Figure 1. Avista average residential charging profile



Source: Avista Corp., Avista Utilities Quarterly Report on Electric Vehicle Supply Equipment Pilot Program, Docket No. UE-160082, February 1, 2017, p. 11.

If multiple customers on a circuit are charging their vehicles at the same time, it could overload the local distribution system and result in the need for costly upgrades. TOU rates are commonly implemented for EV customers,[53] and researchers have repeatedly found these rates to be effective at reducing costs.[54]

Q. What do you recommend regarding optional time-of-use rates?

A We recommend that the Department require the Company to continue to offer these rates on an opt-in basis for all residential customers. In addition, we recommend that customers with electric vehicles be encouraged to adopt time-of-use rates. In order to inform the development of such rates, we recommend that the Department explore

[53] In the United States, at least 17 large investor-owned utilities that have implemented time-of-use rates for EV customers.

[54] Nexant, 2014, "Final Evaluation of SDG&E Plug-in Electric Vehicle TOU Pricing and Technology Study." www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20&%20Tech%20Study.pdf.; Energy and Environmental Economics, Inc. 2014. "California Transportation Electrification Assessment Phase 2: Grid Impacts." Available at https://www.researchgate.net/publication/267694861.

electric vehicle rate design issues in a separate proceeding. We also recommend that the Department revisit the issue of TOU distribution rates more generally to ensure that customers who can shift load to reduce peak distribution circuit demand are provided the price signals to do so.

Q. Why does the Company propose to eliminate inclining block rates?

A. The Company cites the Department's order in D.P.U. 12-25 as its primary rationale for eliminating inclining block rates. In that order, the Department stated that it was "not fully persuaded that inclining block rates continue to accomplish [encouraging energy efficiency]"[55] for several reasons. These reasons hinge on the price signal being too small relative to the total bill to effectively encourage conservation, and a lack of information provided to customers when they have reached the higher block.

Q. Do you agree with this rationale for eliminating the inclining block structure?

A. We agree that the inclining block structure currently provides a very modest price signal to customers. However, a flat rate contains even *less* of an incentive to reduce high electricity usage. Instead of eliminating the price signal, we suggest increasing the differential between blocks to make it more effective.

We also agree that there is inadequate information provided to customers regarding their usage and when they have crossed the threshold between blocks. To ameliorate this, we suggest that the Company implement steps to help customers be more aware of their usage. For example, when a customer's usage in one month crosses the block threshold,

[55] D.P.U. 12-25, p. 468.

the Company could highlight this on the customer's bill and explain that the customer is paying more for usage above the threshold. While this would not help the customer's bill in the previous month, it might help encourage the customer to reduce usage going forward.

Q. What do you recommend regarding inclining block rates?

A. We recommend that the Department maintain and strengthen inclining block rates, at least until more sophisticated rates (such as TOU rates) become widespread for residential customers.

Q. What is the Company's rationale for imposing a customer charge of $8.00 for all residential customers?

A. The Company states that an $8.00 residential customer charge strikes a balance between results of the cost of service study, while "creating a fair distribution of bill impacts across the range of usage within each residential rate class."[56]

Q. How much is the customer charge being increased?

A. The percentage increase in the customer charge varies by location. For customers in Boston and Cambridge, the increase is less than 25%. However, for customers on the South Shore and Cape Cod/Martha's Vineyard, the customer charge would more than double, as shown in the table below.

[56] Exhibit ES-RDP-1, p. 42.

Table 3. Proposed Customer Charge Increase for R-1 Customers

		Current R-1 Customer Charge	Proposed R-1 Customer Charge	Change
R-1	South Shore	$3.73	$8.00	114%
	Cape Cod/Martha's Vineyard	$3.73	$8.00	114%
	Cambridge	$6.87	$8.00	16%
	Greater Boston	$6.43	$8.00	24%
	WMECO	$6.00	$8.00	33%

Q. What concerns do you have regarding the customer charge proposal?

A. As discussed in Section VI, a higher customer charge serves to reduce the distribution charge, which lessens the value of investments in energy efficiency or distributed generation, and reduces the incentive to conserve. Thus higher fixed charges will tend to lead to greater energy consumption and more demand placed on the distribution system, eventually resulting in higher system costs. Further, significant increases in the customer charge are inconsistent with the principle of gradualism.

Q. What do you recommend regarding the customer charge proposal?

A. We recommend that the customer charge be increased to no more than the overall class revenue increase. In order to consolidate rates, the lowest customer charge should be used.

Q. Why is the Company proposing to maintain declining block rates for G-1 customers?

A. The Company states that the declining block rates are driven by a "need to mitigate bill impacts."

Q. How do declining block rates run counter to the principle of efficiency and state energy policy goals?

A. Declining block rates reduce a customer's incentive to invest in energy efficiency or distributed generation by reducing the value of the marginal kilowatt-hour saved. For example, under the G-1 BOS Non-Demand rate, the distribution rate per kilowatt-hour is $0.069 for the first 2,000 kWh, but drops to $0.026 after 2,150 kWh.[57] In other words, the first 2,000 kWh of energy used are more than 2.5 times more expensive than energy consumption above 2,150 kWh.

Under a declining block rate structure, investments in energy efficiency and distributed generation will reduce the least expensive tier first: in this case, impacting the customer's distribution bill by only $0.026, rather than $0.069 per kWh. In this way, declining block rate structures make energy efficiency and distributed generation less valuable to customers.

Q. Are declining block rates necessary to mitigate customer bill impacts?

A. The Company has proposed to apply a mitigation discount to certain rate schedules and to phase in its proposed new rates over several years. In addition, the Company states that it will "work with customers to evaluate bill mitigation options through energy efficiency measures or through a change in customer load profiles"[58]

[57] Exhibit ES-RDP-3, Schedule RDP-1 (East), lines 20 – 22.

[58] Exhibit ES-RDP-1, page 49.

The Company should employ similar approaches to phase out declining block rates. Importantly, a phase out of declining block rates would make it easier for customers with usage in the tail block to mitigate their bills through energy efficiency or distributed generation.

IX. THE PROPOSED PBRM SHOULD BE REJECTED

The Role of Performance-Based Regulation

Q. Could you please define what you mean by performance based regulation (PBR)?

A. PBR is a departure from traditional cost of service regulation intended to create different incentives for the regulated utility to improve its performance. PBR generally consists of two components: multi-year rate plans (MRPs) and performance incentive mechanisms (PIMs).

A multi-year rate plan is a set of rules governing the rates or allowed revenues of the utility for multiple years into the future, with a regulatory requirement that the utility not have another rate case until the end of a stay-out period. Allowed revenues or rates are designed to change in a known or formulaic fashion from year to year, fully or partially independent of utility costs. Since utility profits depend on the difference between revenues and costs, this structure provides an incentive for the utility to contain and reduce costs over multiple years.

PIMs are sets of metrics with targets and financial implications. They identify particular areas where policymakers or regulators have established expectations for performance, and put money (and therefore profits) on the line to reward or penalize the utility for that performance.

Q. What are the best practices for PBR in the context of growing adoption of distributed energy resources (DERs)?

A. DERs have the potential to significantly advance public policy objectives including reductions in overall system costs. One of the ways that DERs can reduce system costs is by displacing utility capital investments (e.g., through non-wires alternatives). DERs can also help to avoid purchases in the wholesale markets. If a utility has an appropriate set of regulatory incentives, it can be encouraged to utilize DERs to address system needs and reduce total costs, even when it means lower future rate base.

Given the cost-reducing potential of DERs, a PBR structure should be comprehensively designed to:

1) Strengthen the utility's incentive to contain capital expenditures;

2) Include a decoupling mechanism to offset the utility's incentive to sell more energy;

3) Allow for timely recovery of DER-related costs (such as energy efficiency and demand response program costs and distributed generation integration costs); and

4) Include DER-focused PIMs.

We explored these issues in a paper Mr. Woolf wrote with Mark Newton Lowry in 2016, attached as Exhibit SREF-TW/MW-5.

Q. What principles for PBR have been established in Massachusetts?

A. The Department addressed general principles and criteria for incentive regulation (of which PBR is an example) in the context of D.T.E. 96-50, regarding Boston Gas. The Grid Wise Performance Plan panel[59] and Dr. Meitzen[60] have summarized these principles. Of particular interest to us are requirements that any incentive regulation plan (a) result in benefits to customers when compared with traditional regulation; (b) not result in reductions in safety, reliability, or existing standards of customer service; (c) not focus exclusively on cost recovery issues; (d) focus on comprehensive results; (e) be designed to achieve specific, measurable results; and (f) provide for a more efficient regulatory approach. Massachusetts has separately established a requirement for decoupling.[61]

Eversource's PBR Proposal and GMBC

Q. Please summarize Eversource's PBR proposal.

A. Eversource's proposal is primarily a multi-year rate plan proposal that includes a number of interacting components:

[59] Exhibit ES-GWPP-1, pages 71-72
[60] Exhibit ES-PBRM-1, pages 10-11
[61] DPU Order 07-50-A

- A revenue adjustment mechanism for each year between rate cases.[62] This mechanism would be based on the rate of inflation and an adjustment for the productivity of an average utility (proposed to be 2.56% on top of the inflation).[63]
- A commitment to invest an incremental $400 million in an identified set of grid modernization categories, referred to as the Grid Modernization Base Commitment (GMBC). Additional approved or required investments in grid modernization beyond the GMBC would serve to increase annual allowed revenues by being included in an additional revenue escalation factor.
- A set of reporting metrics that would reflect successful implementation of the proposed GMBC investments. Some of these metrics have implementation targets, but none include financial incentives. Existing PIMs regarding customer service, etc., would remain in place.
- Earnings more than 200 basis points above the approved return on equity would begin to be shared with customers; there is no proposed sharing for under-earning.
- Eversource is required by law to submit its next rate case in five years or less, but the PBRM includes no stay-out commitment to not come in sooner.

Q. What overall incentives would Eversource's PBR proposal provide the Company?

A. The Company would be incentivized to:

- Reduce both capital and operating costs over the period until the next rate case, relative to the revenues embedded in the ARM.

[62] This is referred to as an attrition relief mechanism, or "ARM".

[63] The inflation factor would have a floor of 1%, and the increase would be reduced by 0.25% if inflation exceeds 2%. The Company would also be protected from exogenous events outside of its control.

- Disfavor capital expenditures until the test year for the next rate case, when there is no more regulatory lag and rate base increases can be captured with minimal depreciation.
- Spend exactly $400 million in the identified investment areas. When combined with the incentive to reduce overall spending, this encourages the Company to find ways to classify already-planned investments as GMBC investments, to use GMBC investments to reduce other capital or operating costs, and to classify expenses as grid modernization expenses not covered by the GMBC and thus subject to separate treatment.
- Complete GMBC implementation, where there are implementation targets, to avoid reputational harm. There is no financial incentive to achieve any particular level of performance or outcomes from the GMBC investments.
- Spend no more than is required to meet service quality and other minimum performance standards. Earnings sharing starting at 200 basis points above the approved ROE encourages the Company to shift costs between years to minimize sharing.

<u>Flaws in Eversource's PBR Proposal</u>

Q. Does Eversource's proposal exemplify the best practices you identified and the established Massachusetts criteria?

A. No. First, it lacks a commitment to stay out of a rate case for any specific period of time. Second, it lacks incentives for the Company to promote and use DERs to the benefit of customers and the system as a whole.

Q. What is wrong with not having a required stay-out period?

A. The reason to have a stay-out period is to impress upon utility management the imperative to reduce costs.[64] If the Company can always fall back on a rate case if cost cutting fails to meet expectations, then the cost control incentive is nearly eliminated.

Q. What do you recommend regarding a stay-out period?

A. If the Department approves a MRP for Eversource, it must include a strong stay-out period provision to achieve the intended utility incentive. Four or five years until the next rate case would be appropriate.

Q. Does Eversource's plan increase transparency and minimize the risk of manipulation?

A. No. As noted above, the Company's PBRM would encourage the Company to classify already-planned investments as GMBC investments. While Eversource proposes a stakeholder process prior to annual plan filings detailing its GMBC investments, that process has not been described in detail and investment authority would remain with the Company. Otherwise, the Company makes no commitment to greater transparency regarding its costs or decision-making processes.

Annual GMBC investment plans would be subject to regulatory review, but there is no proposed process for the annual examination of all capital and operating expenditures to determine whether assignment of each cost to the GMBC is appropriate. While

[64] For a more extensive discussion of the incentives inherent in well-designed multi-year rate plans, see Section 2.5 starting on page 24 of Exhibit SREF-TW/MW-5 (Lowry and Woolf).

Eversource claims that its PBR proposal would have significantly less regulatory overhead than a capital cost adjustment mechanism, the burden of an annual cost-assignment proceeding should not be underestimated.

Q. Would Eversource's proposed PBRM increase the Company's incentives to modernize the grid and empower customers to reduce overall system costs?

A. Only partly. As described above, the PBRM would provide the Company with an incentive to use GMBC expenses to reduce other costs. For example, automating billing for DER customers should reduce labor costs currently used for manual billing. Careful design and use of the GMBC investments could reduce other Company costs. However, there are no other aspects of the PBR proposal that would encourage the Company to maximize net system benefits from its own and others' grid-related or DER investments.

Q. Eversource claims that the GMBC would represent incremental capital investment. Has the Company justified that claim?

A. No. Eversource has presented no evidence regarding the set of prudent and cost-effective investments the Company would make absent the GMBC. As a result, the Department has no record on which to conclude that the proposed GMBC investments are actually incremental. To take one clear example: the GMBC includes an investment in improved billing software and processes to automate billing for net metering customers. Given the pace of the growth in net metering, the cost of manual billing and correcting errors must also be growing. By including billing software in the GMBC, and calling it incremental, Eversource is asking the Department to believe that it would not upgrade its billing software simply to control these costs in the next few years anyway.

If the proposed GMBC investments were part of a well-justified plan for grid modernization, it would be clear how they relate to other costs, what benefits they provide in reduced O&M or other capital costs, and how they incorporate the savings that third-parties might also bring to the grid. Unfortunately there is no such plan.

Q. Does Eversource's PBR proposal provide an incentive to control costs within the GMBC investment?

A. No. Eversource says it will have "strong incentives to control the costs of GMBC investments."[65] However, the PBR mechanism as proposed provides no such incentive. In fact, by requiring the expenditure of $400 million even if cost-effective implementation of the proposed investments could be completed for less, it removes incentives to reduce costs below $400 million.

Q. Do the Company's proposed GMBC metrics provide sufficient incentives for the Company to deliver on its GMBC commitments?

A. No. Eversource receives no benefit for exceeding the targets identified in its GMBC metrics, and no penalty for failing to meet them. The metrics and targets as proposed are general enough, and its ability to shift investment plans flexible enough, that if the Company sees a risk of overspending, it would be able to shift investments or reduce scope without facing a serious risk of formally violating any of its commitments.

[65] Exhibit ES-GWPP-1 at page 10, line 8.

X. PRE-APPROVAL OF THE GMBC IS NOT WARRANTED

Q. Please elaborate on the Grid Modernization Base Commitment.

A. Eversource proposes to spend an incremental $400 million over five years on a set of grid modernization investments within defined categories.[66] While it has identified a proposed spending plan, the Company would retain the flexibility to shift expenditures among categories over the five years of the plan.[67] At its next rate case, the remaining undepreciated value of each investment would be added to rate base (after regulatory review in that proceeding). The Company has proposed a set of metrics for implementation and customer benefit for most of the GMBC investments, and a set of targets for implementation.[68]

Q. Would expenditures under the GMBC be pre-approved?

A. Eversource has requested two kinds of pre-approval regarding the GMBC.[69] First, the Company asks for pre-approval that the proposed categories of GMBC investment are reasonable and appropriate and thus eligible for future inclusion in rate base. Second, it asks for a finding that the total amount of expenditure associated with each identified category of expenditure is reasonable and appropriate. This includes both the total amount of investment and its allocation among categories.

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[66] Exhibit ES-GMBC-2, page 10.

[67] Exhibit ES-GMBC-1, page 21, lines 7-9.

[68] Exhibit ES-GMBC-3. There are no customer benefit metrics associated with the "Foundational Technology for DMS and Automation" initiative.

[69] Exhibit ES-GMBC-1, pages 20-21.

Q. Is pre-approval of capital investments appropriate?

A. The Department has provided limited pre-approvals for specific types of investments, under certain conditions. For example, in its Order 12-76-A, the Department identified principles for pre-authorization of investment in advanced metering infrastructure. In its Order 12-76-B, the Department elaborated to allow pre-authorization of capital investments that are part of a utility's Short Term Investment Plan.

However, in these orders, the Department was clear that if pre-approval is allowed, it only approves the prudence of the decision to implement the grid modernization investment, and does not cover the prudence of its implementation or whether the eventual investment is used and useful.[70]

Q. What conditions did the Department put on the distribution utilities regarding pre-approval?

A. In 12-76, the Department required that grid modernization investments requesting pre-approval be accompanied by benefit-cost analyses (even while acknowledging that there will be many benefits that are difficult to quantify).[71] In order for the Department to be assured that a pre-approved investment represents prudent planning and decision-making, it must have an opportunity to review a cost-benefit analysis as part of a comprehensive business case.

[70] DPU Order 12-76-A at pages 18-19, DPU Order 12-76-B at page 19.

[71] DPU Order 12-76-A at pages 20-25, Order 12-76-B at page 17-18.

Order 12-76-B establishes that "[c]apital investments included in the STIP must be supported by a comprehensive business case analysis. The business case analysis should include: (1) a detailed description of the proposed investments, including scope and schedule; (2) the rationale and business drivers for the proposed investments; (3) identification and quantification of all quantifiable benefits and costs associated with the STIP; and (4) identification of all difficult to quantify or unquantifiable benefits and costs."[72]

Q. Are there other considerations for pre-approving investments?

A. Pre-approval requires a high level of assurance that the proposed categories of investments are the correct investments among the universe of possible investments. In addition to the benefit-cost analyses described above, assurance could be assisted by an open stakeholder process. Such a stakeholder process could allow the Company to present the expected impacts of each kind of investment and get feedback regarding the need for and prioritization among various options. Stakeholder engagement could also illuminate alternatives, including alternatives to utility investment, with lower overall costs.

Q. Has Eversource met the criteria for pre-approval of its GMBC?

A. No. First, Eversource has not presented a "business case analysis" of any sort for the GMBC investment portfolio, much less an analysis that meets the standard established in

[72] DPU Order 12-76-B page 17.

Order 12-76-B. The lack of any estimates of quantified benefits that the GMBC investments would provide for the Company's customers is particularly striking.

Second, Eversource has not consulted with stakeholders regarding the overall structure of this set of grid modernization investments. (It has consulted with stakeholders regarding individual components, such as energy storage or marketing and outreach around electric vehicles.) As a result, there is no body of shared understanding regarding the relative priority and impact of the proposed investments, nor what the impacts would be of investing in these categories instead of others. Stakeholder engagement could also have enabled the Company to refine or develop its cost-benefit analysis.

If we look to Eversource's filings in DPU 15-122/15-123 for further insights or analysis, we are still left without a coherent and comprehensive vision or plan. Tim Woolf and Ariel Horowitz's testimony in that proceeding describes the Company's filed plan:

> It "lacks a comprehensive description of distribution system needs and the resources available to meet those needs, an evaluation of those resources, or a well-justified proposal of a resource plan that appropriately balances cost with other system considerations. Instead, the Company has presented a plan to receive pre-approval for millions of dollars of spending on investments that fail to comprehensively address the Department's goals and requirements for grid modernization. These proposed investments are supported by a justification that

> depends more on rhetoric than on a detailed discussion of costs, outcomes, and alternatives."[73]

Further, Eversource's incremental grid modernization plan was found to lack sufficient attention to furthering DER integration and customer engagement (including third-party DER providers). The Company's plan also failed to include a set of metrics that would allow the DPU and stakeholders adequate visibility of the Company's progress towards achieving a broad transformation of the grid.[74]

Q. What is your recommendation regarding Eversource's request for pre-approval?

A. We are asked to take the Company at its word that the GMBC reflects "no regrets" investments that deliver near term benefit and provide a foundation upon which further innovations will build, i.e., these specific investments are needed regardless of what happens next in relation to the integration of DER."[75] If Eversource believes this is correct, it should be willing to take the risk that its investments will be determined to be prudent in its next rate case. We recommend that the Department not give Eversource the pre-approval it seeks regarding the GMBC investments, and that it direct the Company to make the investments if they are cost-effective and are in the public interest.

If Eversource were to file a comprehensive business case analysis for some or all of the GMBC investments, the Department could evaluate the analysis, consider evidence

[73] DPU 15-122, Exhibit CLF-TWAH-1 at page 45.

[74] *Id.*

[75] Eversource response to AG-9-4.

submitted by intervenors, and determine if those investments met the standard established in D.P.U. 12-76. After such a determination, the pre-approval might be warranted.

Q. Should the Department affirm that the "relative share of the GMBC commitment allotted to each category reflects an appropriate emphasis for the Company's overall grid-modernization effort" as requested by Eversource (Exhibit ES-GWPP at page 69)?

A. No. If the Department chooses to approve the allocation of the grid modernization investment among the categories proposed by Eversource (or approve some other allocation), that should not determine the appropriate allocation of future investments. For example, a future investment in advanced meters might fall in one of these categories, but should not require commensurate investment in the other categories. Alternatively, there may be future categories of grid modernization investment that would be reasonable and appropriate but are not reflected in this proposal at all.

XI. THE DEPARTMENT SHOULD DIRECT EVERSOURCE TO PURSUE THE PROPOSED ENERGY STORAGE PILOTS

Q. Are the various categories of GMBC investments that Eversource has proposed reasonable?

A. Without a benefit-cost analysis and comparison with other options considered but not proposed, we cannot evaluate whether these are the correct categories or particular investments.

Q. Recognizing that one cannot compare the proposed energy storage pilots with alternatives that Eversource did not propose, are these pilots reasonable?

A. In general, we support the use of storage to reduce costs to customers. In addition, Massachusetts policy supports the deployment of energy storage. The Department of Energy Resources (DOER) and the Massachusetts Clean Energy Center's recent study "State of Charge" (Exhibit ES-GMBC-6) estimates that 600 MW of well-designed and deployed energy storage by 2025 could result in $800 million in system benefits for Massachusetts ratepayers. Passed in 2016, H. 4568 allows DOER to set a utility procurement target for "viable and cost-effective" energy storage systems. The proposed pilots are directed at replacing or displacing "wires" solutions that may be more expensive, and the pilots therefore hold promise. As identified in ES-GMBC-6, "In the 2018 timeframe, storage capital costs are expected to reach $450/MWh, allowing distribution projects targeting traditional cost deferrals and renewable integration to become cost effective."[76] Pilots are an appropriate first step to prove and characterize these uses of energy storage. While we do not yet know what the pilots will cost, nor do we have an estimate of costs avoided, limited pilots allow for learning and technology demonstration. Analysis of these pilots can inform cost-effective use of storage in these and other applications in the future, such as in the context of comprehensive non-wires alternative (NWA) evaluation for traditional capital investments.

[76] ES-GMBC-6 page 160 of 270 of the exhibit; labeled page 118 of the report.

Q. Given that you do not recommend pre-approval of the GMBC investments as proposed, what path forward do you recommend for the proposed storage pilots?

A. Given the qualitative evidence presented by the Company regarding the four proposed pilots in Exhibit ES-GMBC-2, it seems likely that as these pilots proceed (and costs become better known) the Company could produce a business case, including cost-benefit analysis, for these pilots that would support their pre-approval.

Q. How should Eversource approach using energy storage in the future?

A. Eversource should incorporate energy storage into its planning processes and consideration of alternatives. In particular, as demonstrated by the promising sites found for the proposed pilots, storage should receive careful consideration as a component in NWAs.

Q. What value can storage provide on the electric grid, and to whom?

A. Storage can provide multiple sources of value: a recent Rocky Mountain Institute report identified 13 possible sources of value from battery energy storage. [77] Services from storage are valuable to different participants in the energy system. For example, a behind-the-meter storage system may provide uninterruptible power to a customer, and the customer may use that storage to control their demand[78] or time-of-use energy charges or increase self-consumption from on-site generation. At the same time, that system could

[77] Rocky Mountain Institute, "The Economics of Battery Energy Storage", October 2015, https://www.rmi.org/Content/Files/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf

[78] For general service customers with demand charges.

provide value to the distribution utility (deferring traditional capital investment or providing voltage support) and the transmission system (relieving congestion or deferring other capital investment). At the wholesale level, storage can help meet resource adequacy requirements, arbitrage energy prices, or provide regulation, reserves, or black start services. The services that storage can provide are differently valuable to different entities: the customer, their distribution utility, their energy supplier, or the ISO. Compensation for value delivered to each (or most) of these different possible beneficiaries may be necessary for a socially cost-effective storage system to make economic sense for each participant.

Q. Should Eversource plan for storage based on the costs and benefits provided to the distribution system only, or to customers and the electric system as a whole?

A. Planning should be conducted in a manner that takes into account the benefits provided to customers and the utility system as a whole, consistent with how other demand resources (such as energy efficiency) are evaluated. It may be easier to align benefits and costs in the case of behind the meter deployment because of the additional reliability value that storage can provide to its host.

Q. What kinds of information sharing are required to optimize the location and use of storage and other DERs on the grid?

A. To identify the optimal locations for DERs, third-party DER providers would benefit from transparent planning processes and access to utility data. Transparent utility distribution system planning can provide a process whereby third parties can understand utility assumptions, analyze data, and assist in the identification of optimal solutions.

Data will allow them to provide system-wide and other societal benefits along with the local customer benefits their solution can provide.[79]

Q. Has Eversource committed to this kind of planning and data sharing?

A. In some respects, yes, but there is significant room for improvement. It is promising that Eversource is developing hosting capacity maps for solar PV and will "provide access to underlying data for hosting capacity calculations, provided that information does not present a potential cyber security risk. Available information may include existing and proposed generation by feeder."[80] However, hosting capacity can be shaped by the use of storage, so simple solar PV capacity by location may not be sufficient to identify optimal storage solutions for some applications.

Moreover, Eversource's planning processes, whether local distribution planning processes or system-level planning processes like the development of the GMBC, remain inaccessible and opaque to third parties, who can proffer lower-cost alternatives. A Department mandate for transparency, coordination, and data sharing with DER technology providers would facilitate the deployment of DER technology based on system needs, yielding greater benefits for all distribution system users.

[79] For example New York's Distributed System Implementation Plan requirements mandate that the utilities collaborate with stakeholders to develop and implement ways for various DERs to be substituted for traditional grid-based solutions in order to avoid or reduce utility capital or operating costs. This includes the development and sharing of detailed system data, such as 8760 load curves, voltage, power quality, and reliability data for individual feeders and substations. *See:* NY DPS Staff, Staff Proposal Distributed System Implementation Plan Guidance, Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, October 15, 2015.

[80] Eversource response to SREF-1-47, page 2.

XII. NON-WIRES ALTERNATIVES

Q. Can the Department also incentivize the Company for customer benefits achieved through the use of DERs such as storage?

A. Absolutely. One of the most promising areas for such an incentive is cost savings achieved using DERs, such as storage, as part of NWAs. Because we do not know as of now how many NWA opportunities will be identified in the coming years, it would be appropriate to establish an incentive with a reporting structure and financial incentive, but no *a priori* target. This would be possible if, for example, the financial incentive takes the form of shared savings of any net benefits achieved through the NWA.

If Eversource were provided with an opportunity to increase its earnings by harnessing DERs (including customer- or third-party-owned DERs) to reduce or avoid capital investment, it would have an explicit incentive to take DER options seriously and work with the other parties who would receive some benefit from the DERs to find cost-effective solutions from the perspectives of all participants. Such an incentive could be paired with a penalty in situations where the Company did not adequately evaluate or implement DER alternatives.

Q. Does the Company currently use customer-sited DERs to reduce capital investments?

A. No. The Company states that it "does not utilize customer-sited DER technologies to affect power flows. Investments made to address system planning needs only involve

Company owned and maintained assets."[81] Appropriate incentives will facilitate Eversource's ability to find lower-cost solutions that involve others' assets.

Q. Have incentives for NWAs been employed elsewhere?

A. Yes. This kind of explicit incentive has been effective in New York. A prominent example is Consolidated Edison's Brooklyn-Queens Demand Management (BQDM) project, which aims to cost-effectively defer a $1.2 billion substation expense with about $200 million of DER investment.[82] The New York Public Service Commission approved an incentive structure that includes a regulated return on the alternative investments, a 10-year amortization period for the investments, and a 100 basis point adder to the return on equity for BQDM program costs tied to the performance of the alternative investments (the capacity of the measures, the diversity of the DER vendor marketplace, and the reduction in cost per MW compared with the traditional solution).[83]

The California Public Utilities Commission has also established a utility incentive for non-wires alternatives in its rulemaking R.14-10-003. A December 15, 2016 decision in

[81] Eversource response to SREF-1-6, page 2.

[82] BQDM is described in general terms in the article "Another $1.2 Billion Substation? No Thanks, Says Utility, We'll Find a Better Way" available at https://insideclimatenews.org/news/04042016/coned-brooklyn-queens-energy-demand-management-project-solar-fuel-cells-climate-change. The NY Department of Public Service matter number is 14-01390, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800.

[83] M. Whited, T. Woolf, and A. Napoleon, "Utility Performance Incentive Mechanisms – A Handbook for Regulators", pages 81-82. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

that proceeding[84] establishes a framework utilities will use to solicit DER solutions for displacing or deferring the need for capital expenditure on traditional distribution infrastructure, an incentive based on expenditures on the DER solution, and a requirement for each utility to identify one to four projects with which to pilot this approach.

XIII. PERFORMANCE METRICS AND TARGETS SHOULD BE STRENGTHENED

Q. Does Eversource operate under any performance incentive mechanisms today?

A. Yes. Eversource currently has three primary sets of PIMs, relating to service quality, energy efficiency, and interconnection. The service quality guidelines have most recently been updated in Order 12-120-D of December 2015. Energy efficiency program performance is subject to PIMs funded by a statewide incentive pool, as described and ordered most recently in the January 2016 order in DPU 15-160 through DPU 15-169. Interconnection timeliness is incentivized by the Timeline Enforcement Mechanism established in DPU 11-75-F. These existing PIMs provide a solid foundation on which future PIMs can be constructed.

Q. Has Eversource proposed metrics and targets for the GMBC?

A. Yes; they are provided in Exhibit ES-GMBC-3. For each category of GMBC investment, Eversource has suggested implementation metrics along with implementation targets. For

[84] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF .

most categories, it has proposed customer metrics. (There are no customer metrics for "foundational" investments such as sensors, fault indicators, and communications, on which other proposed investments build.)

Q. Do these proposed metrics and implementation targets for the GMBC provide the Company with sufficient guidance and financial incentives?

A. No. Eversource's proposed targets are all implementation targets, addressing the question of "did they do the thing they said they would do," but not addressing the more important questions,of "did they do a good job with it," or "did they achieve the desired outcome?" For example, various tools need to be operational by certain dates in order to meet the targets, but there are no targets around the performance of the tools or whether they are actually being used to improve utility service, and there are no transparent specifications for what "operational" means.

While Eversource proposes to measure some important metrics that reflect the customer experience, they have not proposed targets for any of them. In no case has Eversource proposed any sort of financial consequence for failure to meet a GMBC target. Eversource claims that the concerns that the Department will revoke its entire PBRM for failure to meet its GMBC commitments will be sufficient to motivate its performance. However, as Eversource points out, it believes that "[a]s long as the Company is reasonably fulfilling its commitments under the GMBC (and PBRM), it will be fulfilling its obligations under the plan."[85] It is unlikely that Eversource would see any financial implication from falling short on its proposed metrics, much less revocation of its entire PBRM.

Q. If, as you recommend, the Department declines to pre-approve the GMBC investments, should the Department maintain metrics and targets in the GMBC investment categories?

A. Certainly some metrics and targets should be maintained, but it is important that the metrics are consistent with the policy objectives of the Department. If the metrics identified by the Company help to achieve the Department's desired outcomes, then the Company should report on its progress in these areas, and targets should be established where appropriate. Financial incentives can follow if the targets are well justified and additional incentives are needed.

Q. What outcomes do you recommend be the focus of metrics and targets?

A. Where possible, the Department should focus on outcomes for customers, rather than implementation. While Eversource has not provided targets for customer benefits, we believe that the Department can establish targets with the understanding that they may need to be adjusted over time.

[85] Response to AG-3-12.

Targets should take into account historical performance, but should encourage improvements in performance enabled by the GMBC. For example, in the customer-facing categories of GMBC investment, targets might include:

- A 25% reduction in the time for average interconnection approval;
- Achievement of a certain level of customer/DER provider satisfaction with the interconnection process (influenced by any portal or map product Eversource develops);
- A ten-fold reduction in billing delays and errors for DER customers.

Metrics and targets for EV infrastructure could focus on either utilization (which depends on both EV deployment and identifying promising sites) or utilization per EV (which would measure just the siting and usefulness of each EV charging site).

Rather than assigning a fixed amount of capital spending to a set of grid modernization investments, an approach focused on metrics and targets would incentivize the Company to control costs while also achieving the identified objectives.

Q. How can the Department encourage the use of distributed energy resources with PIMs?

A. The Department can establish PIMs relating to the deployment of DERs, as well as to outcomes linked to their deployment. These metrics would complement the existing PIMs for energy efficiency programs.

As a starting point, DER deployment PIMs would include the following metrics:

- total capacity of distributed generation (by type and size);
- number of energy storage systems, with their cumulative capacity (MW), and energy (MWh);
- demand response capacity and number of participants;
- number of EVs owned by Eversource customers; and
- number of EV charging stations by type (Level 1, Level 2, etc.), host (multi-family housing, workplaces, public, etc.), and level of utility control.

Going beyond reporting of DER deployment, the Department can establish explicit targets where state policy provides guidance (e.g. regarding the amount of PV, number of EVs, and possibly soon the amount of energy storage). Over time, the Department may decide to establish targets for other kinds of DERs.

As we discussed previously, a performance incentive related to effective use of DERs to implement non-wires alternatives would be a good way to encourage DERs.

Q. Would establishing the PIMs and reporting requirements you have described here also require adoption of an multi-year rate plan such as the PBRM, or pre-approval of the GMBC?

A. No. PIMs can be implemented separately (as they already have been for service quality, for example) in order to shape utility behavior. However, if the PBRM and GMBC are approved in a form similar to Eversource’s proposal, they should be accompanied by rigorous PIMs of this sort to ensure utility attention on these important outcomes. It is important to note, however, that if PIMs are implemented for activities and costs that fall outside of the PBRM, they may need to contain incentives to control costs (such as shared savings mechanisms).

XIV. SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. We recommend the following:

1. The Department should reject the Company's proposed MMRC. The Department should articulate that if the Company wishes to propose an MMRC on the grounds of customer equity and cost-shifting from distributed generation customers, it must first conduct a thorough analysis of any cost shifting and demonstrate that it is occurring. This analysis should include all relevant costs and benefits of distributed generation resources, in a manner similar to that for energy efficiency.

2. The Department should not increase the current customer charges by any more than the percentage increases that are applied to the energy charges to attain the class revenue requirements allowed by the Department in this docket.

3. The Department should direct Eversource to maintain voluntary distribution TOU rates for all customers, particularly for customer with electric vehicles. In order to inform the development of electric vehicle rates, we recommend that the Department resume its investigation in D.P.U. 13-182, or open a new docket to explore electric vehicle rate design issues. In addition, the Department should revisit the issue of TOU

distribution rates more generally to ensure that customers who can shift load to reduce peak distribution circuit demand are provided the price signals to do so.

4. The Department should maintain the inclining block rate structure for all residential customers until it is replaced by a more efficient rate structure.

5. The Department should direct the Company to eliminate declining block rate structures for G-1 customers.

6. The Department should reject the Company's PBRM proposal as presented. If the Department approves some sort of multi-year rate plan structure for Eversource, we recommend that the Department:

    a) require a stay-out period before Eversource may file its next rate case; and

    b) reject Eversource's request for pre-approval of $400 million of capital investment in the GMBC. until and unless the Company justifies the investments through a comprehensive business-case analysis demonstrating the investments are a part of a plan for least-cost provision of service.

7. Regardless of whether Eversource operates under a multi-year rate plan, we recommend that the Department:

    a) establish an expectation that Eversource will extend any energy storage pilots undertaken over the next several years to further identify and deploy storage in cost-effective solutions;

b) establish a Department mandate for transparency, coordination, and data sharing with DER technology providers and manufacturers that would enable the deployment of DER technology in response to system needs;

c) establish explicit metrics and targets to guide Eversource's activities for grid modernization, including metrics and targets corresponding to any portions of the GMBC that the Department believes will provide net customer value, along with metrics for enabling and advancing third-party DER provider investment and deployment; and

d) consider explicit metrics and incentives for using DERs to cost-effectively avoid traditional capital investments. These could include financial rewards for especially successful adoption of DERs, and penalties in situations where the Company did not adequately evaluate or implement DER alternatives.

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PROFESSIONAL EXPERIENCE

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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.

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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

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TESTIMONY

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Massachusetts Department of Public (D.P.U. 16-169): Direct testimony of Tim Woolf and Erin Malone regarding Nation Grid’s petition for ruling regarding the provision of gas energy efficiency services. On behalf of the Cape Light Compact. November 2, 2016.

New Jersey Board of Public Utilities (Docket No. ER16060524): Direct testimony regarding Rockland Electric Company’s proposed advanced metering program. On behalf of the New Jersey Division of Rate Counsel. September 9, 2016.

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony regarding Public Service Company of Colorado’s rate design proposal. On behalf of Energy Outreach Colorado. June 6, 2016.

Georgia Public Service Commission (Docket No. 40161 and Docket No. 40162): Direct testimony regarding the demand-side management programs proposed by Georgia Power Company in its Certification, Decertification, and Amended Demand-Side Management Plan and its 2016 Integrated Resource Plan. On behalf of Sierra Club. May 3, 2016.

Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with M. Whited regarding National Grid’s rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

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 14-86): Direct and rebuttal 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.

ARTICLES

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Woolf, T., A. Sommer, J. Nielson, D. Berry, R. Lehr. 2005. “Managing Electricity Industry Risk with Clean and Efficient Resources.” *The Electricity Journal* 18 (2): 78–84.

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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

Woolf, T., M. Whited. 2016. "Show Me the Numbers: A Framework for Balanced Distributed Solar Policies." Presentation for Consumers Union Webinar, December 2016.

Woolf, T. 2016. "Show Me the Numbers: Balancing Solar DG with Consumer Protection." Public workshop on solar distributed generation for the Federal Trade Commission, June 2016.

Woolf, T. 2016. "Rate Designs for Distributed Generation: State Activities & A New Framework." Presentation at the NASUCA 2016 Mid-Year Meeting, June 2016.

Woolf, T., M. Whited. 2016. "3rd Annual 21st Century Electricity System Workshop – Implications of Different Rate Designs." Presentation at the Advanced Energy Economy Institute, April 2016.

Woolf, T., M. Whited. 2016. "Decoupling in Pennsylvania: Advantages, Disadvantages, and Design Issues." Presentation to Pennsylvania Decoupling Stakeholders, February 2016.

Woolf, T. 2016. "Earnings Impact Mechanisms: Energy Efficiency." Presentation at the New York REV Technical Conference, January 2016.

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

Woolf, T. 2015. "Performance Incentive Mechanisms: A Catalyst for Change." Webinar for Power Sector Transformation Group, December 2015.

Woof, T. 2015. "Energy Efficiency Valuation: Boogie Men, Time Warps, and other Terrifying Pitfalls." Presentation at ACEEE Conference on Energy Efficiency as a Resource, September 2015.

Woolf, T., M. Whited, A. Napoleon. 2015. "Thoughts on How to Design Clean Energy Performance Incentive Mechanisms." Webinar for the Western Clean Energy Advocates, April 2015.

Woolf, T. 2015. "Properly Valuing the Benefits and Costs of Energy Efficiency." Presentation at the 2015 National Efficiency Advocates Meeting, April 2015.

Woolf, T. 2015. "Non-Energy Benefits & Efficiency Program Screening." Presentation for Georgia DSM Work Group, March 2015.

Woolf, T. 2014. "Performance Incentive Mechanisms And Their Role in New Regulatory Models." Presentation at Acadia Center Conference, Envisioning Our Energy Future, December 2014.

Woolf, T., M. Whited., A. Napoleon. 2014. "Guiding Utility Performance: A Handbook for Regulators." Webinar for the Western Interstate Energy Board, December 2014.

Woolf, T. 2014. "Planning for Distributed Energy Resources." Presentation for Advanced Energy Economy Webinar, November 2014.

Woolf, T. 2014. "Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits." Presentation to NARUC ERE Committee, November 2014.

Woolf, T. 2014. "Presenting the Full Value of Energy Efficiency: Creating a Better Message." Presentation at Sierra Club Beyond Coal Conference, October 2014.

Woolf, T., C. Neme. 2014. "Regulatory Policies to Support Energy Efficiency in Virginia." Presentation for the 2014 Virginia Energy Efficiency Workshop, October 2014.

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Woolf, T. 2014. "Performance Incentive Mechanisms: Digging Deeper Into Performance-Based Regulation." Presentation for National Governor's Association Conference: Utility Business Models That Align with State Clean Energy Goals, September 2014.

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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.

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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 distributed energy resources, rate design, cost-benefit analysis, integrated resource planning, utility regulation, water use and conservation, 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.

EDUCATION

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

University of Wisconsin, Madison, WI
Master of Science in Environment and Resources, 2010.
Certificate in Humans and the Global Environment (CHANGE).
Nelson Distinguished Fellowship.

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

ADDITIONAL SKILLS

- 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

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

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TESTIMONY

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Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with T. Woolf regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

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

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony of Tim Woolf regarding Public Service Company of Colorado's rate design proposal. On behalf of Energy Outreach Colorado. June 6, 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.

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.

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PRESENTATIONS

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Whited, M. 2016. "Ratemaking for the Future: Trends and Considerations." Presentation to the Midwest Governors' Association, St. Paul, MN, July 14.

Whited, M. 2016. "Performance Based Regulation." Presentation to the NARUC Rate Design Subcommittee. September 12.

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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, Boston, MA, July 28.

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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.

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

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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-

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April 28, 2017
Hearing Officer Tassone

FUTURE ELECTRIC
Utility Regulation

PERFORMANCE-BASED REGULATION IN A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE

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BERKELEY LAB

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in scale to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity on implications are common to both time periods. The U.S. Department of Energy (DOE) played a useful role during the 1990s' discussion and debate by sponsoring a series of papers that illuminated and dug deeper on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues, with the aim to better inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of new and improved technologies, together with changing customer and societal desires and needs, both of which are coupled with possible structural changes in the electric industry and related changes in business organization and regulation. Some of the technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some of the technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To maintain effectiveness in providing reliable and affordable electricity and its services to the nation, power sector regulatory approaches may require reconsideration. Historically, major changes in the electricity industry came with changes in regulation at the local, state or federal levels.

The DOE, through its Office of Electricity Delivery and Energy Reliability's Electricity Policy Technical Assistance Program, is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policy makers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, work closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Glossary of Terms

Attrition Relief Mechanism (ARM): A common component of multi-year rate plans that automatically adjusts rates or revenues between rate cases to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable cost drivers such as inflation and customer growth.

Authorized Return on Equity (ROE): The rate of return allowed by a state regulatory commission for the shareholders of an investor-owned utility, expressed as a percentage of the value of equity capital invested.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital. Base rates generally do not compensate utilities for large, volatile costs such as those for fuel and purchased power, which are often tracked.

Capex: Capital expenditures.

Cost of Service Regulation (COSR): The traditional North American approach to utility regulation that resets rates in occasional rate cases to recover the cost of its service that regulators deem prudent.

Cost Tracker: A mechanism providing expedited recovery of targeted costs. A tracker is an account of allowances for costs that are eligible for recovery. These allowances are then typically recovered via rate riders.

Distributed Energy Resources (DERs): Technologies, services and practices that can improve efficiency or generate, manage or store energy on the customer side of the meter. DERs can include energy efficiency, demand response, distributed generation, energy management systems, batteries and more. Plug-in electric vehicles are considered as part of distributed storage. DERs can be implemented by utilities, customers, third-party vendors or combinations thereof.

Earnings Sharing Mechanisms (ESMs): These share surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity (ROE) deviates significantly from its public utility commission-approved target. ESMs often have "deadbands" (neutral zones around the target) in which earnings variances are not shared with customers.

Efficiency Carry-over Mechanisms: These mechanisms allow for a share of lasting performance gains or losses to be kept by the utility when a multi-year rate plan expires.

Incentive-Compatible Menu: An incentive-compatible menu of regulatory contracts involves different combinations of key ratemaking elements, such as revenue and earnings sharing factors. These can be designed so that the utility, by its choice, reveals the attainable level of cost in a multi-year rate plan, thereby reducing information asymmetry.

Lost Revenue Adjustment Mechanism (LRAM): A ratemaking mechanism that compensates utilities for estimated revenue lost from specific causes such as utility demand-side management programs and distributed generation. An LRAM requires estimates of load impacts.

Marketing Flexibility: Some regulators have deemed it appropriate to provide utilities with greater flexibility to fashion rates and other terms of service in selected markets, typically via light-handed regulation of rates and services with certain attributes. A traditional goal of such flexibility is to retain large-load customers and attract new customers to the utility system. These loads can spread fixed costs and stimulate local economies. Marketing flexibility can also be used to offer customers custom green power packages and value-added services that rely on new technologies. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to protect competitors and prevent cross-subsidization.

Multi-Year Rate Plans (MRPs): A common approach to performance-based regulation that features a multi-year rate case moratorium, an attrition relief mechanism and several performance incentive mechanisms.

Off-Ramp Mechanisms: These mechanisms permit suspension or reconsideration of a multi-year rate plan under pre-specified conditions (e.g., persistent, extreme under- or over-earning).

Ofgem: British Office of Gas and Electricity Markets, the regulator of gas and electric utilities in the United Kingdom.

Opex: Operation and maintenance expenses such as those for labor, materials, services, generation fuel and power.

Performance-Based Regulation (PBR): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (PIM): Metrics, targets and financial incentives (rewards, penalties or both) designed to strengthen performance incentives in targeted areas such as service quality and distributed energy resources.

Rate Base: The net (depreciated) value of utility investment used to provide service, including working capital.

Rate Case: A proceeding, usually before a state regulatory commission, to reset rates that involves a review of the utility's cost and the resetting of rates to recover the revenue requirement. These proceedings may also consider other issues such as rate designs.

Rate Case Moratorium: A set period of time between rate cases designed to reduce regulatory cost and strengthen utility performance incentives. Electricity prices (or revenues) are generally capped during this period, with the exception of cost trackers.

Rate Riders: An explicit mechanism on utility tariff sheets for supplemental revenue adjustments.

Revenue Requirement: The annual revenue that the utility is entitled to collect. The amount is periodically recalculated in rate cases and may be escalated by other mechanisms (e.g., cost trackers and ARMs) between rate cases. It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base less other operating revenues.

Revenue Regulation: By breaking the link between sales and revenue, revenue regulation reduces the incentive for a utility to increase sales between rate cases. Revenue regulation provides the utility with an allowed level of revenues each year, regardless of customer demand and energy use on the utility system. Rates are adjusted to ensure the utility collects no more, and no less, than its allowed revenues. This is sometimes referred to as "revenue decoupling." Revenue regulation does not include lost revenue adjustment mechanisms or straight fixed-variable rate design.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO is an innovative form of MRP that includes a relatively long rate-case moratorium of eight years, a forecast-based attrition relief mechanism, and an innovative set of performance incentive mechanisms.

Statistical Benchmarking: The use of statistics on utility operations to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

Stranded Costs: Fixed or sunk costs that have become uneconomic due to changes in business conditions such as technology, demand, input prices or policies.

Test Year: A specific period used to calculate a utility's rates. Some states use a historical test year and adjust billing determinants, opex, and rate base cost for known and measureable changes. Other states use a fully forecasted test year that considers other possible changes.

Throughput Incentive: Under traditional regulation, utilities can increase revenues by increasing sales between rate cases. Increased sales will in turn result in increased profits for the utility, because the marginal cost of providing additional service is typically well below the rate per unit of use.

Totex: Under RIIO, capital expenditures and operating expenditures are combined into one category: "total expenditures," or "totex" when setting the revenue requirement. The utility earns a return on a pre-determined portion of totex, regardless of whether the utility's capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus non-capital projects.

Used and Useful: A regulatory concept used to determine whether investments may be included in rate base. While state laws vary, generally "used" means that the facility is actually operated to provide service, and "useful" means that without the facility, service would either be more expensive or less reliable.

X-Factor (aka Productivity Factor): A term in an index-based ARM formula that typically reflects the impact of productivity growth on cost growth.

Executive Summary

Performance-based regulation (PBR) of utilities has emerged as an important ratemaking option in the last 25 years. It has been implemented in numerous jurisdictions across the United States and is common in many other advanced industrialized countries. PBR's appeal lies chiefly in its ability to strengthen utility performance incentives relative to traditional cost-of-service regulation (COSR). Some forms of PBR can streamline regulation and provide utilities with greater operating flexibility. Ideally, the benefits of better performance are shared by the utility and its customers.

The shortcomings of traditional COSR in providing electric utilities with incentives that are aligned with certain regulatory goals are becoming increasingly clear. In particular, COSR can provide strong incentives to increase electricity sales and utility rate base. Further, some parties express concern that traditional COSR does not provide utilities with appropriate financial incentives to address evolving industry challenges such as changing customer demands for electricity services, increased levels of distributed energy resources (DERs), and growing pressure to mitigate carbon dioxide emissions. In addition, attention to potential new regulatory models to support the "utility of the future" has renewed interest in PBR.

This report describes key elements of PBR and explains some of the advantages and disadvantages of various PBR options. We present pertinent issues from the perspectives of utilities and customers. In practice, these different perspectives are not diametrically opposed. Nonetheless, this framework is useful for illustrating how various aspects of PBR may be viewed by those key groups. Regulators have a unique perspective, in that they must balance consumer, utility, and other interests with the goal of achieving a result that is in the overall public interest.

PBR Includes Many Elements and Variations

PBR is not a one-size-fits-all construct designed uniformly wherever it is applied. Instead, PBR is made up of several elements intended to strengthen utility performance incentives that can be applied in different ways and in different combinations. Some of these elements are applied as stand-alone elements in regulatory systems that are largely traditional.

The most common approach to PBR worldwide is the multi-year rate plan (MRP), which combines a rate case moratorium with an attrition relief mechanism (ARM) and some performance incentive mechanisms (PIMs). MRPs may also feature revenue regulation (also called revenue decoupling), earnings sharing mechanisms and other techniques. These elements are briefly described in Table ES 1.

MRPs can strengthen incentives for utilities to improve performance in a wide range of initiatives, and the benefits ideally are shared between utilities and their customers. If designed well, MRPs can provide strong incentives for utilities to support or implement DERs.

Table ES 1. PBR Elements

Revenue Regulation	Revenue regulation (revenue decoupling) eliminates the throughput incentive by ensuring the utility recovery of allowed revenue regardless of megawatt-hours (MWh) and megawatts (MW) of utility system use. Allowed revenue is typically escalated using a predetermined formula. Under this approach, the impact on utility revenues between rate cases from energy efficiency, demand response programs, and customer-sited distributed generation can be reduced or eliminated.
Performance Incentive Mechanisms (PIMs)	PIMs consist of performance metrics, targets and financial incentives. PIMs have been employed for many years to address performance in areas such as reliability, safety and energy efficiency. In recent years, PIMs have received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding DERs and the implementation of new technologies and practices.
Multi-Year Rate Plans (MRPs)	MRPs permit utilities to operate for several years without a general rate case. The rate case moratorium typically lasts four to five years. Between rate cases, an attrition relief mechanism (ARM) automatically adjusts rates or the revenue requirement according to the predetermined formula that compensates a utility for cost pressures without tracking its actual cost. ARMs are commonly based on cost forecasts, indexed trends in utility costs, or a combination of the two. MRPs generally also include PIMs and may include revenue regulation and cost trackers.
RIIO ("Revenue = incentives + innovation + outputs")	RIIO is the PBR approach used in Great Britain, where MRPs have been used to regulate utilities for more than 25 years. RIIO is the latest MRP system for energy utility regulation. Key elements of the RIIO approach include an eight-year plan term, revenue regulation, a forecast-based revenue cap escalator, and innovative use of PIMs. RIIO is often cited as a potential model for regulating the "utility of the future."

Key Advantages and Disadvantages of Multi-Year Rate Plans

Customers' Perspective

MRPs can strengthen incentives for utilities to improve performance in a wide range of initiatives, and the benefits ideally are shared between utilities and their customers. If designed well, MRPs can provide strong incentives for utilities to support or implement DERs. MRPs can also provide utilities with additional marketing flexibility where regulators deem this desirable, while providing some protection for customers taking service under standard tariffs. MRPs can also reduce regulatory cost.

However, some regulators and consumer advocates may lack the expertise and funding needed to effectively consider the implications of MRPs and to address design issues. A utility's revenue may exceed its costs for extended periods. When regulators introduce tools to contain these variances, such as earnings sharing mechanisms, utility performance incentives may be weakened.

Utility's Perspective

MRPs give utilities more opportunities to profit from improved performance. They can provide utilities with greater marketing flexibility to meet competitive challenges, retain large load customers, and satisfy the complex, changing demands of customers. Improved performance can become a new profit center for a utility at a time when traditional opportunities for earnings growth are diminishing. Less frequent rate cases can help utility managers focus on their basic business of providing customer-responsive services cost-effectively. Reduced regulatory cost is particularly valued by utility companies that operate in multiple jurisdictions.

On the other hand, MRPs can increase operating risk, without providing the utility with a compensatory adjustment to the authorized return on equity. Revenue may occasionally fall short of cost. Further, rate plans can be designed in such a way that customers receive most benefits, leaving the utility at a disadvantage.

Key Advantages and Disadvantages of Performance Incentive Mechanisms

Customers' Perspective

PIMs allow regulators and stakeholders to provide detailed guidance to utilities with regard to specific performance areas and the desired outcomes. They can be offered incrementally and gradually, thereby reducing customer risk.

This detailed guidance can also create tension among the parties involved. If there are significant incentives at stake, proceedings to design and approve PIMs can be complex, contentious and resource intensive. In practice, PIMs tend to focus on performance areas that are relatively easy to identify and evaluate, such as service quality, reliability and demand-side management (DSM) implementation, but may overlook other performance areas that also require improvement.

If not well-designed, PIMs can suffer from several pitfalls that would be detrimental to customers, such as disproportionate rewards, lax standards or unintended consequences.

If not well-designed, PIMs can suffer from several pitfalls that would be detrimental to customers, such as disproportionate rewards, lax standards or unintended consequences. Financial rewards and penalties need to strike the right balance: low enough to mitigate regulatory risk, but strong enough to incentivize correct utility behavior. This balance can sometimes be difficult to achieve.

Utility's Perspective

PIMs alert utility managers to special concerns of regulators and customers, helping to maintain good relationships among the parties to regulation. PIMs, like MRPs, can provide new earnings opportunities in an era when traditional opportunities are diminishing for some utilities.

But chosen metrics are sometimes difficult to control. Targets can be unreasonable at the outset or ratcheted unfairly as performance improves. Many PIMs involve penalties but no rewards, which is counter to the workings of competitive markets, where good performance typically results in higher revenue. When PIMs do offer rewards, they are often relatively small due to low reward rates and the limited scope of PIMs.

Are Stand-Alone PIMs Better Than Multi-Year Rate Plans?

The recent resurgence of interest in PBR in the United States has often focused on the addition of stand-alone PIMs to existing regulatory systems, rather than implementing MRPs or refining MRPs when they are already in use. This report discusses the advantages and disadvantages of MRPs and stand-alone PIMs.

Customers' Perspective

Relative to MRPs, PIMs tend to be simpler, more transparent, less risky, and more focused on specific performance areas of interest to regulators. While the design of PIMs is also subject to some

Relative to MRPs, PIMs tend to be simpler, more transparent, less risky, and more focused on specific performance areas of interest to regulators.

controversy and complexities, the stakes are generally much lower than in MRP design, and the process may be less contentious. On the other hand, stand-alone PIMs have to provide sizable incentives if they are to induce utilities to fully embrace energy efficiency and other DERs wherever they are preferable to utility capital expenditure. Important areas of utility performance such as general cost containment could in principle be addressed by PIMs, but typically are not.

MRPs incentivize a broader array of performance improvement initiatives. A well-designed MRP with revenue regulation and appropriate PIMs for DERs may be the most effective way to promote DERs. MRPs may also reduce the frequency of general rate cases and can therefore substantially reduce regulatory cost, unlike stand-alone PIMs.

Utility's Perspective

Stand-alone PIMs can make more sense for utilities when the current regulatory system yields adequate revenue, investment opportunities are ample, and regulators and stakeholders are resistant to the types of sweeping changes associated with MRPs. It is sometimes difficult for the utility and stakeholders to agree on compensatory revenue escalation in an ARM.

MRPs make more sense for utilities when the regulatory community is receptive and containing regulatory cost is a special concern due, for example, to ownership of multiple utilities. In some cases, it is relatively easy for the utility and stakeholders to agree on a set of revenue escalation provisions.

MRPs can increase utility marketing flexibility by allowing a utility to provide alternative prices and products to some customers without a rate case and without affecting customers in other rate classes. The need for flexibility may increase in coming years in order to:
(a) contend with increased competition from distributed generation;
(b) provide customers with tailored clean energy products; and
(c) offer optional rates and new services that advanced metering infrastructure makes possible.

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies.

What Can the United States Learn From the British Approach to PBR?

Customers' Perspectives

The United Kingdom's RIIO approach to regulation has been mentioned in several recent papers as a promising new regulatory model for the "utility of the future." It offers numerous regulatory innovations. For example, converting multi-year cost forecasts into ARMs with inflation adjustments provides more inflation protection than the "stair-step" ARMs that are popular in the United States. Incentive-compatible menus have promise in the design of ARMs and other plan provisions. RIIO uses PIMs to creatively address new performance areas.

Regulators and stakeholders who are satisfied with current utility performance, and expect continued satisfactory performance in a high DER future, may prefer to maintain current regulatory practices. Regulators and stakeholders who wish to improve performance comprehensively and also wish to focus on some specific areas of performance in need of improvement should consider MRPs with an appropriately tailored package of PIMs.

Despite its innovation, RIIO is an unusually expensive and time-consuming approach to MRP design. Further, requiring eight years between rate cases significantly reduces the ability of regulators and stakeholders to review utility investments. North American regulators have developed alternative approaches to MRP design that are also worth considering. These include ARMs based on indexes, PIMs for DSM, efficiency carry-over mechanisms, and the use of settlements to establish MRP terms.

Utility's Perspective

ARMs based on multi-year cost forecasts can help fund expected cost increases and sidestep controversial indexing and benchmarking research. Inflation adjustments reduce operating risk.

On the other hand, some utilities may resist the extensive use of independent benchmarking and engineering studies in the British approach to ARM design. Eight-year ARMs do not provide utilities with much flexibility for dealing with unforeseen challenges, even if they are based on a utility's own forecast.

A Roadmap for Regulators

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies. In general, discussions of PBR options in a high DER future should evaluate and balance the range of potential PIM and MRP options that might fit any one jurisdiction.

Table ES 2 presents a summary of how various PBR options might match different regulatory goals. The left column identifies the performance improvement goals a state might have; the middle column indicates the extent to which regulators and stakeholders are open to making regulatory changes; and the right column indicates the combination of PBR options that might be appropriate for that state.

Table ES 2. Regulatory Options to Fit Different Contexts and Meet Different Goals

Performance Improvement Goals	**Openness to Regulatory Change**	**PBR Options**
None	Low	Maintain current ratemaking practice
Improvement in specific areas	Low	Adopt PIMs for specific areas
General improvement in utility performance Streamlined regulation	Moderate to high	Adopt an MRP
Support for DERs	Low	Adopt PIMs for DER *or* revenue regulation
Support for DERs	Moderate	Adopt PIMs for DERs *and* revenue regulation
Support for DERs General improvement in utility performance Streamlined regulation	High	Adopt PIMs for DERs, an MRP and revenue regulation

Regulators and stakeholders who are satisfied with current utility performance, and expect continued satisfactory performance in a high DER future, may prefer to maintain current regulatory practices.

Regulators and stakeholders who would like to promote improvements in utility performance should consider what areas of performance are most in need of improvement and are most critical in a high DER future. If their main concern is to improve performance in specific areas, stand-alone PIMs might be sufficient to address these areas. If they instead seek wide-ranging performance improvements, including better capital cost management, MRPs may be better suited to these goals than PIMs alone.

Regulators and stakeholders who wish to improve performance comprehensively and also wish to focus on some specific areas of performance in need of improvement should consider MRPs with an appropriately tailored package of PIMs. For example, an MRP with revenue decoupling, tracker treatment of DER-related costs, and PIMs related to cost-effective DERs can provide strong encouragement for utilities to support cost-effective DERs.

1. Introduction

Performance-based regulation (PBR) of utilities has been implemented in numerous jurisdictions across the United States and is common in many other advanced industrialized countries. PBR can strengthen utility performance incentives relative to traditional cost-of-service regulation (COSR), reduce regulatory cost and provide utilities with greater operating flexibility. The end result can be better utility performance.

In a potential future where there is a high reliance on energy efficiency, peak load management, distributed generation, storage and other kinds of distributed energy resources (DERs), there may be an increased need for performance-based types of regulation, for several reasons:[1]

- Under COSR, utilities generally have strong financial incentives to increase rate base and electricity sales. This creates a disincentive to utilize cost-effective DERs to reduce utility system use and avoid new capital investments. In a possible high DER future, there may be even greater need to mitigate utility financial disincentives to support cost-effective DERs.

- Technologies are changing, and the pace of such change may accelerate in a high DER future. To cope with technological developments, utilities must innovate, develop new planning practices, and be accorded increased operating flexibility.

- As technologies and systems evolve rapidly, a new generation of stranded costs and used-and-useful issues may arise. Utilities may need more regulatory guidance regarding whether and how to invest in rapidly evolving technologies. One of the many ways to provide such guidance is through the use of targeted performance incentive mechanisms (PIMs).

- New technologies also increase opportunities to offer customers new services in areas such as energy efficiency and demand response, installing and operating distributed generation resources, providing customer and other data necessary to support DERs, and providing access to third-party providers of DERs. In a high DER future, regulators may wish to encourage strong performance in supporting new types of customer services.

- In a high DER future, electric utilities will be under considerable pressure to keep costs as low as possible.[2] Well-designed and executed PBR mechanisms can provide incentives to strengthen utility performance and keep costs down.

This report addresses several questions regarding the role that PBR could play in a high DER future. In particular:

1. Does traditional COSR provide utilities with appropriate regulatory direction and incentives in a high DER future?

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[1] During the transition to a high DER future, there may be instances where some utility infrastructure becomes obsolete prior to the end of its book life. In such cases, regulators will need to consider how to address ongoing cost recovery for prudently incurred investments, regardless of regulatory regime — COSR or PBR.

[2] See the first report in Berkeley Lab's Future Electric Utility Regulation series, by Corneli and Kihm (2015).

2. Can some form of PBR provide improved regulatory direction and incentives in a high DER future?
3. What are the alternative elements of PBR and the key ways of designing PBR mechanisms, and what are the implications of the different PBR approaches in a high DER future?
4. What are the key challenges and controversies with regard to PBR designs and practices?
5. What are the implications for utilities, regulators, customers, and the public interest of PBR designs and practices?

In Chapter 2 we provide a detailed description of COSR and various ratemaking elements of PBR. In Chapter 3 we discuss the issues that should be considered when evaluating PBR, and in Chapter 4 we describe criteria that can be used to evaluate whether and how to implement PBR. We discuss in Chapter 5 several key challenges and controversies regarding the implementation of PBR from different stakeholder perspectives. Chapter 6 draws some conclusions and provides a roadmap for regulators.

2. Ratemaking Tools for a High DER Future

2.1. Ratemaking Elements

PBR is essentially a package of ratemaking tools or elements that can be applied in different ways and in different combinations. Some of those elements are not unique to PBR; they are also sometimes added to largely traditional regulatory systems. To make matters more confusing, the industry uses a variety of terms to describe similar, or overlapping, regulatory approaches. For example, PBR around the world has chiefly taken the form of multi-year rate plans (MRPs) that include one or more performance incentive mechanisms. However, PBR could also take the form of a package of performance incentive mechanisms (PIMs) without an MRP.

Table 1 provides a summary of ratemaking elements for various regulatory constructs. The first column lists ratemaking elements that are frequently included in PBR mechanisms. The other columns include the different regulatory constructs relevant to our discussion, including Great Britain's approach to PBR, referred to as "RIIO."[3] The following sections discuss each of these constructs at some length.

Table 1. Ratemaking Elements and PBR

Ratemaking Elements	***COSR***	***Performance-Based Regulation***		
		Stand-Alone PIMs[4]	***MRP***	***RIIO***
Rate Case Moratorium	---	---	Yes	Yes
Attrition Relief Mechanism (ARM)				
Forecast-based ARM	---	---	Sometimes	Yes
Index-based ARM	---	---	Sometimes	---
Hybrid ARM	---	---	Sometimes	---
Marketing/Pricing Flexibility	Occasionally	---	Sometimes	---
Earnings Sharing Mechanisms	---	---	Sometimes	Yes
Efficiency Carry-over Mechanisms	---	---	Sometimes	---
Performance Incentive Mechanisms	---	Yes	Usually	Yes
Revenue Regulation (Decoupling)	Sometimes	Sometimes	Sometimes	Yes

3 Revenues = Incentives + Innovation + Outputs. See Section 2.6.

4 Adopting one or two PIMs should not be considered PBR, but adopting several PIMs in a more comprehensive way could be.

As indicated in Table 1, MRPs typically include most or all of the ratemaking elements related to PBR. Also, regulators often add PIMs, revenue regulation and cost trackers to COSR to provide utilities with specific incentives. However, each jurisdiction tends to implement MRPs differently, including or excluding particular elements to suit their particular needs.

2.2. Cost of Service Regulation

The approach used in the United States to regulate retail rates of investor-owned electric utilities has long been the subject of analysis and criticism. Regulators in other countries have been openly skeptical about the desirability of traditional COSR, and they have proven more willing than U.S. regulators to use PBR. Some recent U.S. commentaries have suggested that traditional regulation is ill-suited for regulating the electric "utility of the future" and have touted PBR as an alternative.[5] This section of the report explains traditional regulation and considers some of its limitations.

COSR Explained

The general approach that state public utility commissions use to regulate retail rates of electric utilities developed over decades.[6] This regulatory system is called "cost-of-service regulation" because rates for each utility are designed to recover the particular utility's costs of providing service. We discuss here common features of COSR, noting that there are many variations on the theme in the United States.

The chief means of adjusting rates under COSR is the general rate case. In these litigated proceedings, the base "revenue requirement" is set equal to the normalized net cost of service in a test year. The cost of service is calculated as the sum of electric operation and maintenance expenses (opex), depreciation, taxes, and a return on the net (depreciated) value of utility investments (rate base). *Net* cost is calculated by subtracting any revenue the utility garners from sources other than tariffed retail electric services.[7]

In principle, the entire net cost of service can be subject to a prudence review in each rate case. Prudence reviews can be time-consuming and controversial since prudence can be difficult to assess, and the dollars at stake encourage parties to argue their positions energetically. Another frequent source of rate case controversy is the target rate of return on the equity component of rate base.

In contemporary COSR, regulators sometimes use cost trackers to address some utility costs more promptly than rate cases can achieve. A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered costs that are deemed prudent by regulators. Recovery of these costs is then typically initiated promptly using tariff sheet provisions called "riders."

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5 See, for example, e21 Initiative (2014); Lehr and O'Boyle (2015); Fox-Penner, Harris and Hesmondhalgh (2013).

6 The Federal Energy Regulatory Commission (FERC) uses a substantially different system to regulate interstate power transmission. Formula rate plans (a kind of broad-based cost tracker) are common.

7 For both vertically integrated utilities and utility distribution companies, "other revenue" includes revenue from miscellaneous other products and services that are enabled using utility assets. An example is rental of land under transmission lines. For vertically integrated utilities, the largest source of other operating revenue is typically sales in bulk power markets.

Large, volatile costs like those for fuel and purchased power are traditionally collected through cost trackers. The components of rates that address the less volatile costs of non-energy inputs such as labor, materials and capital are sometimes called "base rates."[8]

Trackers are also used sometimes to compensate utilities for costs that are rapidly rising and do not produce much counterbalancing revenue, whether or not they are volatile.[9] Costs of accelerated capital expenditures are most commonly tracked on the basis of this rationale.

To establish rates, the revenue requirement must be allocated across the utility's services. For each service, rates are then set to recover the assigned revenue requirement given assumed quantities of "billing determinants." Most base rate revenue is typically drawn from usage charges, which vary with a customer's use of the system,[10] while the balance of revenue is typically drawn from fixed customer charges.

Utilities file rate cases with state public utility commissions when their net cost of service is expected to exceed revenue from tariffed retail services.[11] The timing of these cases is irregular and depends on business conditions. For example, rate cases are more frequent in a period of rapid inflation.

The frequency of rate cases for vertically integrated utilities versus restructured distribution utilities can differ. Because vertically integrated utilities own generation capacity, a higher share of their assets is needed to serve variable load. In an era of increasing reliance on DERs, the reduced need for utility-owned generation assets may reduce the need for rate cases. New capacity that is needed may be purchased in bulk power markets. Depreciation of older plants slows rate base growth, which also may reduce the need for rate cases.

Regulatory Issues

Regulatory Cost and Its Consequences

Regulatory cost is an important and underappreciated consideration in choosing a regulatory system. In the case of COSR, the overriding cost concern is general rate cases since the entire net cost of a utility must be reviewed and all rates must be reset.[12] Rate cases typically last six months or more and require considerable resources from utilities, regulators and other stakeholders. Expenses incurred in a rate case can easily reach into the millions of dollars. Regulators understandably seek ways to contain regulatory cost. The pressure to do so increases to the extent that rate cases are frequent, numerous utilities are regulated, and rate case issues are controversial.

A number of tools can help contain regulatory cost, but some traditional economy measures have undesirable side effects. Limiting the utility's rate and service offerings, for instance, reduces the difficult chores of allocating the revenue requirement across services and considering the impact of

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8 Base rate revenue is sometimes called "margin."

9 Examples of operation and maintenance expenses that are sometimes tracked due in whole or part to their rapid growth include those for health care.

10 Volumetric and demand charges are the most common usage charges. Demand charges are based either on the customer's peak hourly receipts during the billing month or year, or its receipts at coincident (system) peaks. For commercial and industrial customers, demand charges collect most base rate revenue. For residential customers, base rate revenue is typically drawn chiefly from volumetric charges.

11 Rate cases are also occasionally compelled by the commission or instigated by other parties that claim overearning.

12 Rate cases nonetheless have benefits, which include the opportunity to review utility operations and provide feedback.

utility offerings on market competition. These restrictions on marketing flexibility are undesirable to the extent that customers have diverse and rapidly changing needs for utility services. There is also a risk that customers will uneconomically bypass the utility's system, causing other customers to pay higher rates.

Another traditional measure for lowering regulatory cost is to limit detailed prudence reviews to issues that are especially controversial, such as sustained generating plant outages or poor responses to major storms. However, prudence reviews suffer from several shortcomings. Lower-profile but nonetheless important prudence issues may receive insufficient attention. Funding for commission staff and consumer groups to review prudence is often limited. Prudence reviews are based on financial penalties for poor performance, but do not allow for financial rewards for superior performance. In practice, a significant part of the cost of service receives little or no detailed review. For example, disallowances are rare for costs of replacing aging assets.

To reduce the frequency of general rate cases, regulators can use cost trackers to address volatile or rapidly rising costs that could otherwise trigger frequent general rate cases. Both of these economy measures can weaken utility performance incentives, including the incentive to contain rate-base growth, as we discuss below.

Incentive Issues

To understand COSR incentive issues, it may help to consider the performance incentives of firms in competitive markets. The market for corn is illustrative. Corn prices are sufficient to provide producers *as a group* with a competitive rate of return *in the long run*. Returns of equally efficient producers vary (due, for example, to differences in weather), and efficient producers may occasionally be unable to earn competitive returns (due, for example, to slack demand or supply gluts). Prices are completely insensitive to the cost of *individual* producers. Farmers thus keep all of the incremental, after-tax profit from their efforts to reduce their costs. This strengthens their cost containment incentives. Owning farmland or corn-producing and drying equipment is not a goal in itself, and many corn producers rent some of the acreage, equipment and storage capacity they use. Consumers benefit in the long run as industry productivity growth drives down the real price of corn. In a period of weak demand, the price of corn falls. This stabilizes consumption and compels producers to try all the harder to contain cost. Note also that prices vary with the quality of corn, so that farmers have an incentive to make sure that their corn complies with established quality standards.

The incentives embedded in such competitive markets differ from incentives embedded in COSR for electric utilities in two important respects. First, incentives to contain cost are weaker to the extent that a utility's revenue tracks its own cost closely; were its revenue to track its cost exactly, a utility could grow its earnings only by growing its rate base. The closeness with which cost tracks revenue under COSR is greater to the extent that rate cases are frequent and trackers address a large share of cost.[13] Rate cases might happen more frequently when growing reliance on DERs causes use of the utility's system to grow more slowly than its capacity. COSR thus contains the seeds of a disequilibrium situation in which increasing competition from DERs weakens performance incentives, making utility service less attractive and thereby encouraging further inroads by competitors.

[13] Trackers can be designed to strengthen cost containment incentives but typically are not.

Second, to the extent that a utility's rate of return exceeds the cost of capital, electric utilities have an incentive to make excessive capital investments. Under such conditions, capital spending becomes a goal in itself.

Regulators in other countries display much more concern with utility performance incentives than their American counterparts. For example, the Alberta Utility Commission discussed the incentive problem with traditional regulation in a letter announcing a generic proceeding to consider PBR for provincial energy distributors. These companies were filing frequent rate cases in a period of rapid regional economic growth.

> This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources […] These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing.[14]

This proceeding ended in a mandate for all Alberta energy distributors to operate under MRPs.

Rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources.

DERs pose special incentive issues under COSR. Consider first that all forms of DERs reduce revenue from usage charges. Since costs of non-energy inputs such as capital are largely fixed in the short run, increased reliance on DERs reduces utility earnings until base rates can be raised in the next rate case.[15] This disincentive abates with more frequent rate cases.

A second incentive issue arises from the fact that DERs can reduce opportunities for utilities to grow rate base. The problem is greatest for assets, such as generation capacity and substations, the need for which is closely tied to load. The need for substations is especially sensitive to peak load, whereas the need for generation assets also depends on the volume of service.

The disincentive to facilitate DERs is offset to the degree that utilities can profit from slowing rate base growth. Under COSR, utilities benefit from slowing rate base growth only between rate cases. Any resulting reduction in the depreciated value of rate base in the test year for the next rate case is passed entirely to customers. For example, the portion of the revenue requirement corresponding to an aging distribution substation that has not been replaced due in whole or part to DERs is reset in the next rate

14 Alberta Utilities Commission (2010), pages 1–2.

15 The lost revenue problem is less pronounced for vertically integrated utilities, since a higher percentage of their base rate input costs are load related, and idle generating capacity can be used for profitable off-system sales.

case to its lower, more depreciated value. The incentive to contain rate base growth thus falls with the frequency of rate cases and the pervasiveness of trackers for load-related capex costs.[16]

Many other costs that are sensitive to DERs are recovered through cost trackers, and this also weakens incentives to embrace DER solutions. Most notable are the costs of fuel and purchased power.[17] For example, energy efficiency programs provide an opportunity for a utility to reduce the cost of purchased power, but the utility has little to no incentive to reduce purchased power costs if they are simply passed through to customers in a cost tracker. The weak incentive of utilities to contain tracked fuel and purchased power expenses is quite important in an age when generation fleets burn large amounts of price-volatile natural gas, and a sizable share of the power requirements of most utilities is purchased rather than self-generated.

Utilities, like other firms, also do not profit from savings in many costs that their operations impose on others. Chief among these are "external" costs, like those from carbon and other emissions from fossil-fueled generation, which are not reflected in electricity prices in most regions of the United States. This further weakens utility incentives to embrace DER solutions.

Consider, finally, that DERs can affect service quality in positive and negative ways, but utility revenue is not as sensitive to the quality of service as revenue typically is in competitive markets. Thus, a utility is not automatically rewarded for improvements in reliability that might result from DERs. Revenue is also largely insensitive to the quality of connections and other special services provided to DER customers.

We conclude that utilities under traditional regulation have a material disincentive to accommodate DERs, even when DERs meet customer needs at lower cost than traditional grid service.[18] In addition, utilities are largely indifferent to other potential benefits of DERs. The importance of utility disincentives for DERs is increasing in an era in which customers have mounting interest in DERs, and the electricity industry is increasingly reliant on DERs to reduce its environmental impacts.

Mandates Are Not Always Enough

Key aspects of utility behavior can and should be mandated. For example, regulators approve the designs of a utility's retail rates. They can use this authority to ensure that rate designs send the right signals to customers regarding the cost of services that they might request. Generation plant additions are controlled through such means as integrated resource planning, certificates of public convenience and necessity, competitive bidding, renewable portfolio standards and prudence reviews. Measures like these may be more extensively used in the future to control distribution plant additions. Wherever regulators and other policymakers can effectively administer mandates, there is less need for incentives.

We conclude that utilities under traditional regulation have a material disincentive to accommodate DERs, even when DERs meet customer needs at lower cost than traditional grid service.

16 Capital cost trackers can be designed, however, to strengthen capex containment incentives.
17 Some utilities also have tracker treatment of transmission expenses.
18 Under COSR utilities are, in other words, incented to oppose efficient levels of DERs.

There are nonetheless several benefits to complementing mandates with strengthened utility incentives. The case of DERs is illustrative. Poorly incentivized utilities will not, for example, use their considerable influence to proactively promote cost-effective DERs, and may oppose such resources.

A poorly incentivized utility will also be less cooperative at implementing established policies. For example, utilities can stress the downside of DER options in integrated resource and distribution planning exercises. As another example, lengthy delays in processing distributed generation connection requests have produced long queues for distributed generation customers at some utilities.[19] The burden of regulation is thereby increased.

COSR Refinements

Much as growth in the demand for electric vehicles has been slowed by continuing improvements in petroleum-fueled vehicles, the need for PBR can be mitigated by the continuing evolution of traditional regulation. For example, revenue decoupling can reduce the utility disincentive to embrace energy efficiency. More funds can be made available for the independent review of utility performance in rate cases and occasional audits and benchmarking studies. Cost trackers can be incentivized. Regulators can make more use of integrated resource planning and extend it to the distribution system.

2.3. Revenue Regulation

As described in Section 2.2, traditional COSR provides utilities with a financial incentive to increase sales and a corresponding disincentive to reduce sales. Under COSR, base electricity prices are fixed between rate cases, which means that utilities can increase revenues by increasing sales between rate cases. Increased sales will in turn result in increased profits for the utility, because the marginal cost of providing additional service is typically well below the price of electricity. This effect is sometimes referred to as the "throughput incentive," because utilities can increase revenues and profits by increasing the amount of electricity they deliver.

Revenue regulation is a modification to ratemaking designed to eliminate the throughput incentive by weakening or severing the link between utility sales and revenues.[20] Revenue regulation helps a utility recover its allowed level of revenues each year, regardless of electricity consumption.[21] This is accomplished with the following steps:

a) The utility's revenue requirements for the test year are set in a general rate case, using the same practices and principles that are used under traditional cost-of-service ratemaking.

b) A certain amount of "allowed revenues" are determined for the years following the test year. In theory, these allowed revenues could be held constant at the level of revenue requirements determined for the test year. In practice, the allowed revenues are typically adjusted each year to account for the expectation that utility system costs will change in the years between rate cases due, for example, to input price inflation and growth in the number of customers served.

19 Stanfield (2015a).

20 Revenue regulation is frequently referred to as "decoupling." We use the term "revenue regulation" throughout this report because it is more descriptive than "decoupling."

21 For a more detailed discussion of revenue regulation, see Regulatory Assistance Project (2011).

c) On a periodic basis between rate cases (e.g., each year), the utility's revenues are reconciled to ensure that the actual revenues recovered equal the allowed revenues. This is often accomplished with a separate reconciling rate rider. In those periods where the utility's actual revenues exceed the allowed revenues, customers will be refunded the difference, and vice versa.

In this way, actual revenue collected will track the allowed revenue more closely. Note that under this approach, the utility's revenues will be unaffected by all factors that could increase or reduce sales, including energy efficiency and demand response programs administered by the utility and third parties, more stringent building codes and appliance efficiency standards, naturally occurring energy efficiency,[22] new rate designs, increases in non-utility-owned distributed generation, the impacts of weather, and the impacts of the economy on customer consumption patterns. There is no need to estimate load impacts.

Revenue regulation is currently in place for electric utilities in 14 jurisdictions across the country[23] and is being actively considered in several other states.[24]

Key Design Issues

Revenue regulation mechanisms can be designed in many different ways, with significant implications for utility cost recovery and for customers.[25] In our view, revenue regulation mechanisms should achieve three key goals: (1) eliminate the throughput incentive; (2) improve the alignment of utility revenues and costs; and (3) ensure that customers are protected and are in fact better off than they were prior to revenue regulation.

Revenue regulation mechanisms should include at least the following key provisions to help protect customers:

- The initial test year rates should be set in the course of a full rate case, applying traditional ratemaking practices and principles, and with meaningful input from consumer advocates and other stakeholders.
- If allowed revenues are modified over time, they should be modified in a way that is simple, transparent, and best reflects expected changes in cost pressures that may occur between rate cases.
- Reconciling rate adjustments should occur on a relatively frequent basis, at least once a year, to avoid any large impact on rates at the time of the adjustments.

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22 Naturally occurring energy efficiency is that which results from normal market forces and technological improvements in the absence of utility programs or governmental intervention.

23 Lowry, Makos and Waschbusch (2016).

24 For example, Nevada and Missouri are currently considering whether to implement revenue regulation. See Public Utilities Commission of Nevada (2015) and Missouri Public Service Commission (2015). Note that the Nevada PUC held several workshops on decoupling mechanisms in spring 2015, finally adopting temporary regulations that modified the current lost revenue adjustment mechanism (which is not full revenue regulation) on June 10, 2015. Full revenue regulation may be adopted in the future.

25 We use the term "revenue regulation" to refer to the general approach of severing the link between utility sales and revenues by setting revenues instead of setting prices; and we use the term "revenue regulation mechanism" to refer to the specific details of the ratemaking approach that is used in any one jurisdiction.

- Reconciliations should be capped to limit the amount that rates can be increased at any one point in time — e.g., 3 percent of annual utility revenues.
- Regulators can consider whether the utility's allowed return on equity should reflect the fact that utility revenues, and therefore profits, will be less volatile under revenue regulation.

One other key design issue is the choice to apply revenue regulation to all utility customers or to only a portion of them. Some jurisdictions have chosen to exclude large commercial and industrial customers. One reason this is done is to avoid having to reassign large revenue shortfalls if customers of this kind sharply reduce their service requests. Another is a concern that utilities should maintain some incentives to retain such customers, encourage expansion of their local operations, and attract new customers to the service territory.

Role in a High DER Future

While revenue regulation has frequently been employed to mitigate a utility's financial disincentive to support energy efficiency, it can also address a utility's financial disincentive for other DERs that reduce customer electricity consumption from the grid, such as distributed generation and storage. Consequently, revenue regulation may be a useful ratemaking tool for regulators who wish to support the implementation of DERs. This is true regardless of whether regulators prefer that utilities or third parties play the lead role. Either way, utilities will be in a highly influential position regarding DER development and implementation.

Furthermore, electricity sales growth has declined in many regions of the United States in recent years for a variety of reasons. This has offset the financial benefit of the slower input price inflation that has occurred since the recession. As legislative and regulatory pressures increase over time to address climate change, electricity sales growth may decline even further. In the context of declining sales growth and increasing levels of DERs (whether naturally occurring through significant declines in technology costs, utility induced, third-party induced, or encouraged by public policies), utilities may need some form of revenue regulation because COSR may not provide them with sufficient revenues in a timely fashion to recover costs of serving customers.

> *While revenue regulation has frequently been employed to mitigate a utility's financial disincentive to support energy efficiency, it can also address a utility's financial disincentive for other DERs that reduce customer electricity consumption from the grid, such as distributed generation and storage.*

Role in Relation to PBR

Revenue regulation is a fairly flexible tool that can be implemented in the context of traditional COSR or PBR. Efficiency PIMs are often added to revenue regulation to provide some "positive" incentive to use energy efficiency to slow rate base growth. The positive incentive can be further strengthened by combining revenue regulation and efficiency PIMs with a multi-year rate plan. MRPs in the past have often applied a price cap, but can instead feature a "revenue cap" without affecting the rest of the MRP mechanism.

A detailed analysis and discussion of the advantages and disadvantages of revenue regulation in a high DER future is beyond the scope of this study. We present the summary above to indicate how this ratemaking tool might or might not fit into the structure of PBR. We do not address this topic further in this report.

Lost Revenue Adjustment Mechanisms as an Alternative to Revenue Regulation

Lost revenue adjustment mechanisms (LRAMs) are sometimes used as an alternative to revenue regulation. Under this approach, utilities are compensated for the estimated loss of base revenue that results from their energy efficiency programs, and possibly also from distributed generation. The LRAM approach can be problematic and challenging for several reasons.

First, LRAMs significantly increase the need for accurate estimates of energy savings from energy efficiency programs. With large dollars riding on the outcome, proceedings to estimate lost revenues can be extremely contentious, distracting and resource intensive. For this reason, LRAMs tend to focus on utility energy efficiency programs with savings that are easy to estimate. This means that they do not fully eliminate the financial disincentive to promote sales, nor do they offset the financial disincentive for other initiatives that could reduce sales and costs, such as tighter building energy codes and appliance standards and time-varying rates.

Second, LRAMs should allow utilities to recover only a portion of lost revenues — the portion that is necessary to cover fixed costs that are embedded in rates. It can be difficult to properly isolate this portion of rates. If not done properly, the utility might recover more or less than necessary to be made whole.

Furthermore, LRAMs should not allow utilities to recover revenues that the utilities can recover by alternative means. For example, some vertically integrated utilities can offset lost revenues from efficiency programs by increasing off-system sales. The portion of off-system sales that are not passed through to customers can offset lost revenues from efficiency programs. It can be difficult to identify and quantify all of the ways that lost revenues are offset.

Furthermore, LRAMs often result in automatic, escalating annual increases in rates, which can become significant as customers adopt increasing levels of energy efficiency and distributed generation resources. Decoupling, on the other hand, typically results in modest adjustments to rates, and these adjustments can reduce rates as often as they increase rates.[26]

In a high DER future, it would essentially be impossible and overly burdensome to accurately calculate lost revenues for all types of DERs. Revenue regulation does not suffer from the above challenges and can address all types of DERs and new technologies that might decrease or increase customer sales.

2.4. Performance Incentive Mechanisms

Targeted PIMs have been employed for many years to address traditional performance areas such as reliability, safety and energy efficiency. In recent years, these mechanisms have also received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding DERs and other less-conventional technologies and practices.[27]

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26 Morgan, P., A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations, Revised May 2013.

27 See, for example, New York Public Service Commission (2014), which explores the role of PIMs to meet similar policy goals.

Targeted PIMs can be incorporated into any regulatory model, including traditional COSR and MRPs. By providing explicit metrics, targets, and in some cases financial rewards or penalties, PIMs can provide guidance on how utilities can meet state regulatory policy goals and encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the current regulatory system.[28]

Targeted PIMs can be incorporated into any regulatory model, including traditional COSR and MRPs.

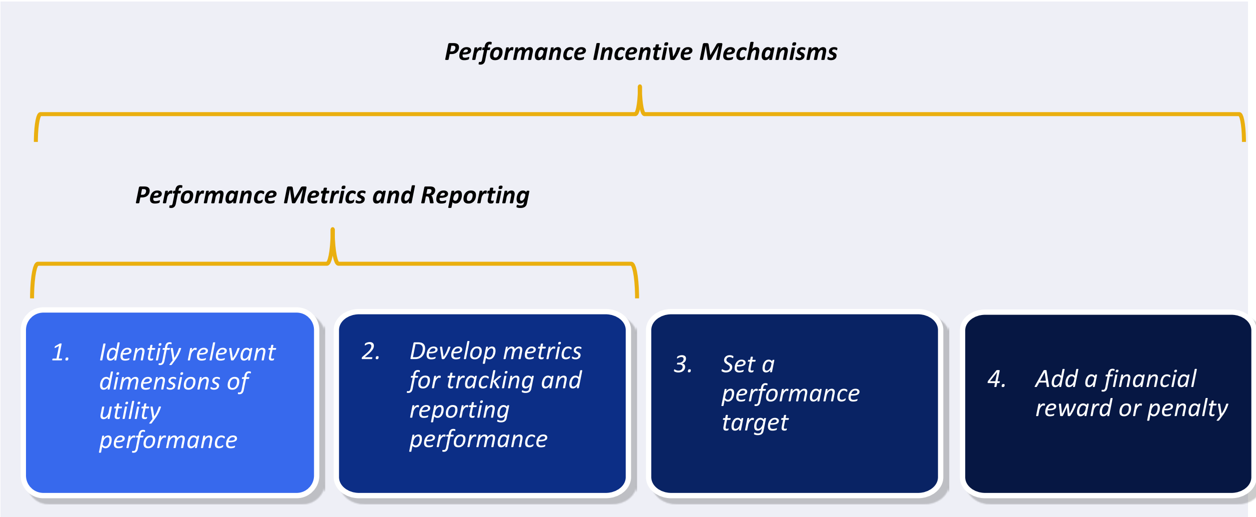
PIMs typically consist of four components:

1. *Regulatory policy goals* that specify certain performance areas of interest, as well as objectives for those areas
2. *Metrics* that provide detailed information about the utility's operations in the specified areas of interest
3. *Targets* that reflect performance goals, as measured by the metrics
4. *Financial incentives* (rewards and/or penalties) that are based on the utility's performance relative to the target

Not all of these components need to be implemented to guide utility performance and guard against underperformance. In some cases, simply implementing metrics without targets or financial incentives is sufficient. Similarly, some metrics may have targets but no financial incentives. Regulators may wish to adopt these different components incrementally over time, based on experience gained from those elements that have been adopted. Figure 1 shows the components of performance incentive mechanisms. The sections that follow discuss metrics, targets and financial incentives in the context of regulatory policy goals.

[28] Whited, Woolf and Napoleon (2015).

Figure 1. Components of Performance Incentive Mechanisms



Metrics

A metric is simply a quantitative measurement. However, a performance metric should provide more than data; it should provide useful information for assessing how well a utility is progressing toward meeting policy objectives. Thus, a metric must be directly tied to the underlying policy goal and should be reasonably objective and subject to utility control. Identifying a metric that meets these criteria can be difficult.

Metrics must also be precisely defined and should use standard regional or national definitions where possible. To promote transparency and reduce the possibility that data will be manipulated, metrics should be easily measured and interpreted, and the data independently collected or verified.

Utility performance areas that have a long history of monitoring using metrics include reliability, safety, customer satisfaction, power plant performance and costs, as Table 2 indicates. Metrics for monitoring these traditional performance areas are generally well developed, and the data are readily available.

Table 2. Traditional Performance Areas

Performance Dimension	Purpose of Metrics
Reliability	Indicate the extent to which service is reliable and interruptions are remedied quickly (e.g., SAIDI and SAIFI)
Customer Service	Ensure that the utility is providing adequate levels of customer services
Plant Performance	Indicate the operating performance of specific generation resources (e.g., availability factor)
Cost	Indicate the cost of service (e.g., rates, unit cost and productivity)
Employee Safety	Ensure that employees are not subjected to excessive safety risks
Public Safety	Ensure that the public is not subjected to excessive safety risks

Source: Whited, Woolf and Napoleon (2015)

Evolving policy goals and industry challenges are increasingly prompting the development of new performance metrics. Areas of interest include system peak load management, usage per customer, network support services for distributed generation, and environmental impacts and clean energy goals. Table 3 provides examples of these emerging performance areas and metrics for tracking them. Metrics such as these will be important as states seek to both drive greater reliance on DERs and ensure that DERs are deployed effectively for greatest system benefit.

Table 3. Emerging Performance Areas

Performance Dimension	Purpose of Metrics
System Efficiency	Indicate the extent to which the utility system as a whole is being operated more efficiently — e.g., in terms of load factor
Customer Engagement	Indicate the extent to which customers are implementing energy efficiency, demand response, distributed generation and other DERs
Network Support Services	Indicate the extent to which customers and third-party service providers have access to the network
Environmental Goals	Indicate the extent to which the utility and its customers are reducing environmental impacts, including climate change

Source: Whited, Woolf and Napoleon (2015)

Performance Targets

Targets should be challenging, but realistically achievable. A number of analytical techniques can be used to determine targets, including historical performance (provided that historical conditions are still relevant), statistical benchmarking using peer utility data (after controlling for inherent differences among utilities), and utility-specific studies (such as engineering studies).[29]

In all cases, the cost of achieving a performance target must be balanced with the expected benefits to customers. Some jurisdictions have utilized customer surveys to help determine the value of an incremental improvement in utility performance to customers. For example, Ontario and Alberta have relied on customer surveys to determine whether customers would be willing to bear the costs of improved reliability,[30] and Norwegian regulators have used surveys to construct a willingness-to-pay curve that represents how customers value various levels of reliability.[31]

In some cases, targets should be adjusted based on new information, new technologies or other factors. However, regulators should avoid sudden and significant changes to targets in order to provide the utility with certainty regarding longer-term investments. In addition, care must be taken not to unduly "ratchet" targets as utility performance improves.

Financial Rewards or Penalties

In general, financial rewards or penalties in PIMs should be large enough to capture management attention, but not overly reward or penalize the utility. Starting with a small reward or penalty avoids problems like financial instability, excessive costs to customers, and backlash that potentially undermines the entire performance incentive mechanism.[32] However, rewards or penalties that avoid controversy may not be high enough to have sufficient incentive impact, and this shortcoming may not be realized for several years.

An additional feature of well-designed PIMs is that they avoid "cliff effects," or substantial changes in earnings due to small changes in performance. Not only do cliff effects create uncertainty regarding utility earnings, but they also introduce significant controversy and contention to the measurement and verification process.

Deadbands (neutral zones around the target) can mitigate the implications of setting a target and associated incentives too high or too low, and reduce rate adjustments due to the natural volatility of metrics. Deadbands are frequently set at one standard deviation of historical performance, but may be larger or smaller based on sample size and the tolerance for error. That is, if a large amount of historical data is available, then one standard deviation is likely to capture most of the normal variation in a metric. For example, a target level for system reliability measured as the System Average Interruption Duration Index (SAIDI) may be set at 60 minutes, with a deadband of two minutes. Thus no rewards or penalties would be provided until performance fell outside of the 58 to 62 minutes range.

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29 Frontier analysis identifies the most efficient firms and creates an efficiency frontier based on these firms' input usage per unit of output. Other firms are then assigned a score based on their efficiency relative to the efficiency frontier. For further information, see Shumilkina (2010).

30 Pollara (2010) and Alberta Utilities Commission (2012).

31 Growitsch (2009).

32 Some performance areas may need larger financial incentives than others. Also, if regulators wish to fundamentally shift utility incentives away from current incentives, then the combined effect of PIM financial incentives may need to be significant.

In some cases, asymmetrical rewards or penalties may be appropriate. Reward-only incentives are easier for utilities to accept, especially for metrics that are new and are not subject to close utility control, and may result in more collaborative and less adversarial processes. On the other hand, penalty-only incentives are sometimes appropriate when performance above the target provides little additional benefit to customers.

ENERGY EFFICIENCY PIMS

Energy efficiency is the most common focus of PIMs in use in the United States today, and the experience with these PIMs can shed light on the opportunities and the challenges of using PIMs in the context of DERs in general. Energy efficiency PIMs have been in use since the early 1990s. They are intended to: (a) help overcome utility resistance to reduce sales; (b) encourage utility management buy-in for energy efficiency programs; (c) provide incentives for utilities to deliver successful, effective programs; and (d) ultimately align utility incentives with energy efficiency goals established through public policy.

Almost 30 states have established some sort of PIM for electric energy efficiency programs.[33] While efficiency PIM designs vary across the states, they fall into four general categories:[34]

- *Shared net benefit incentives*. The utility can earn a portion of the net benefits of the energy efficiency programs, defined as the present value of the difference between the efficiency program benefits (typically the avoided costs) and costs (typically the costs to deliver the program). (12 states)
- *Energy savings-based incentives*. Incentives are determined for achieving or exceeding predetermined energy savings goals, either in terms of energy (kilowatt-hours), capacity (kilowatts), or both. (6 states)
- *Multifactor incentives*. The calculation of incentives includes multiple metrics, either designed to promote specific efficiency initiatives that might otherwise be overlooked (e.g., contractor training courses) or to achieve specific public policy goals. (5 states plus the District of Columbia)
- *Rate of return incentives*. Utilities are allowed to earn a rate of return on their energy efficiency spending, in order to make the financial incentives for efficiency investments comparable to those for supply-side investments. (1 state)

Most energy efficiency PIMs have several incentive points — for example: (a) a threshold point below which no incentives are earned (e.g., 80 percent of savings); (b) a target point at which the target amount of the incentive can be earned (e.g., 100 percent of savings); and (c) a cap beyond which no additional incentives can be earned (e.g., 120 percent of savings). The amount of money that is made available for efficiency PIMs varies widely across the states, but tends to be on the order of 5 percent to 15 percent of energy efficiency program budgets.

Energy efficiency PIMs are generally recognized as being effective in achieving more aggressive and more effective energy efficiency programs. Two recent studies found that PIMs significantly contributed to buy-in by corporate management, motivated utility management and influenced energy efficiency planning.[35]

Note that energy efficiency PIMs alone do not remove the utility's incentive to increase sales or to increase rate base. Revenue regulation, or some comparable approach to address lost revenues, is needed to offset the utility throughput incentive. In addition, energy efficiency PIMs alone do not provide financial rewards to eliminate the utility incentive to increase rate base. But they do offset this incentive and typically provide sufficient incentive to encourage utilities to implement successful energy efficiency programs.

Performance Incentive Mechanisms in a High DER Future

PIMs can counter undesirable incentives inherent in the existing regulatory framework. They also can provide guidance and incentives to pursue new regulatory goals, such as interconnecting distributed generation and storage, investing in grid modernization, or adopting practices to support electric vehicles. Table 4 provides examples of metrics that regulators may wish to consider in a high DER future, grouped into two categories: DER deployment and network support services. DER deployment metrics can provide an indication as to how well utilities are facilitating adoption of DERs through utility programs (such as energy efficiency and demand response programs), electricity pricing structures (such as net metering and time-varying rates), and customer usage information. Metrics related to network support services, on the other hand, are focused on how well the utility is facilitating DERs by providing appropriate grid infrastructure and data access.

Table 4. Examples of Potential DER-Related Performance Metrics

Area	Metric	Purpose
Distributed Energy Resource Deployment	Energy efficiency (EE)	Indication of participation, energy and demand savings and cost-effectiveness of EE programs
	Demand response (DR)	Indication of participation, demand savings and cost-effectiveness
	Distributed generation (DG)	Indication of the technologies, rate of DG penetration, energy and demand savings and cost-effectiveness
	Energy storage	Indication of the technologies, capacity and growth of utility and customer-sited storage installations and their availability to support the grid
	Information availability	Indication of customers' ability to access their usage information
	Time-varying rates	Indication of saturation of time-varying rates
	Electric vehicles (EVs)	Indication of customer adoption of EVs and their availability to support the grid
Network Support Services	Advanced metering capabilities	Indication of metering functionality
	Interconnection support	Indication of DG installation support
	Third-party access	Indication of network access by third-party developers
	Provision of customer data	Indication of customer access to relevant data

2.5. Multi-Year Rate Plans

Salient Features

MRPs are the most common approach to PBR around the world. The basic idea is to compensate a utility for its services for several years with revenue that, while reflective of cost pressures, does not closely track the utility's own cost of service. The competitive market paradigm provides some intuition for this approach. Imagine, for example, that utility distribution companies in the northeastern United States were paid a set fee to provide quality electric service to each customer of a certain type, and that these fees were designed to permit distributors in the region as a whole to earn a competitive rate of return in the longer run. With revenue that is independent of their own cost of service, utilities would then have strong incentives to contain their costs using DERs and other strategies. Benefits of the resultant industry productivity growth in the region could be passed through to customers. Rates paid to individual utilities could in principle be adjusted to reflect variations in local input prices, system undergrounding, and other external business conditions.

While a regulatory system of this kind is technically feasible, real-world MRPs are rather different because regulators and utilities alike do not want the revenues of individual utilities to stray too far from their cost of service. MRPs utilize two tools to relax the link between a utility's own cost and its revenue:

1. A moratorium is imposed on general rate cases that typically lasts two to four years. These moratoria can permit a substantial reduction in regulatory cost.

2. Between rate cases, an attrition relief mechanism (ARM) automatically adjusts rates or the revenue requirement for changing business conditions such as inflation and customer growth without linking the relief to the utility's own cost growth.

MRPs typically address some costs separately from ARMs using cost trackers. Tracker treatment is useful for costs that are difficult to address using ARMs.

The combination of a rate case moratorium and the ARM approach to rate escalation can strengthen cost containment incentives and permit an efficient utility to realize its target rate of return on equity (ROE) despite a material reduction in regulatory cost.

Some MRPs have earnings sharing mechanisms (ESMs), which share surplus or deficit earnings, or both, between utilities and customers. These earnings result when the ROE deviates from its commission-approved target. Off-ramp mechanisms may permit suspension of a plan under pre-specified outcomes such as persistently extreme ROEs.

Plan review and termination provisions are also important in MRPs. Some plans require rates to be reset in a rate case. When this happens, any lasting cost savings or inefficiencies realized during the plan are passed entirely to customers, and this weakens utility performance incentives. Some plans provide for a review of the MRP toward the end of the plan period, and these reviews may result in a plan extension without a general rate case.

Other plans provide for a rebasing at the end of a plan that deliberately lacks a full true-up of the revenue requirement to the utility's net cost. Provisions of this kind are sometimes called "efficiency carry-over mechanisms" because they permit the utility to keep some benefits of lasting performance gains, and perhaps also to absorb some lasting costs of poor performance after a plan expires. A utility might thereby be able to keep for some period of time a margin from sales related to electric vehicles (EVs) or savings in substation costs that it achieved from aggressive use of DERs. These mechanisms can strengthen incentives to pursue efficiency gains without unusually long plan periods that complicate ARM design.

Most MRPs also include PIMs. These have in the past been used chiefly to balance incentives for cost containment with incentives to pursue other goals that matter to customers and the public. PIMs used in MRPs for electric utilities have been especially common for energy efficiency, reliability and customer service (e.g., telephone response time, timeliness in meeting scheduled appointments and connections, and the accuracy of invoices). MRPs for vertically integrated utilities may sensibly include PIMs for generator performance. In the future, MRPs are likely to include PIMs that address new concerns such as peak load management and the quality of connections and other services offered to distributed generation customers.

MRPs can also encourage better marketing by utilities where regulators deem this desirable. Rate cases are less frequent, and this reduces the chore of allocating costs across service classes. Rate adjustments that are required (due, for example, to ARMs) can be effected using formulas that insulate one group of customers from rate and service offerings to other customers. The MRP framework therefore reduces concerns about affording utilities more marketing flexibility. MRPs can also permit utilities to keep benefits of improved marketing longer, especially when they feature a well-designed efficiency carry-over mechanism. Utilities can then have stronger incentives to develop market-responsive rates and services in targeted areas.

One area where improved marketing is valuable is service to price-sensitive, large-load customers. Power costs are especially important to these customers, and they often have the option of self-generating or operating in other service territories. Better marketing is also needed for green power and EV rates and services for all customer classes.[33] In addition, advanced metering infrastructure can be used to provide time-sensitive base rates that help utilities send the right price signals and encourage customers to use their systems in less costly ways. Advanced metering infrastructure, distributed storage, and other new distribution technologies open the door to many new value-added services, including premium quality services. Utilities can also work harder to boost traditional sources of other operating revenues such as line attachment fees for cable and telecommunications (telecom) companies.

Application to DERs

MRPs can improve utility incentives to embrace DERs, if properly designed. Inherent advantages include the general incentive they can provide to slow rate base growth. Since DERs can be effective tools for reducing rate base growth, utilities have a stronger incentive to embrace them. For example, if a utility uses DERs to reduce the need for substation capex, it can keep some of the cost savings for several years, and possibly longer if there is a well-designed efficiency carry-over mechanism.

MRPs can improve utility incentives to embrace DERs, if properly designed. Inherent advantages include the general incentive they can provide to slow rate base growth. Since DERs can be effective tools for reducing rate base growth, utilities have a stronger incentive to embrace them.

MRPs can also incorporate mechanisms to weaken the short-term link between revenue and sales, such as revenue regulation. When an MRP features revenue regulation, the ARM escalates allowed revenue. Utilities in California and Hawaii, which have experienced the highest levels of distributed solar generation penetration in the United States, operate under MRPs with revenue regulation.[34] A utility's incentive to embrace DERs under an MRP can be further strengthened by the addition of DER-related PIMs and by tracker treatment of DER-related expenditures.

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[33] A base rate for EV service could, for example, be tied to the price of gasoline.
[34] Solar generation is also encouraged in these states by other conditions, including strong sunlight.

Role of Consumer Advocates

The role of consumer advocates may change in an MRP regulatory system. Rate cases may occur less frequently but those that do occur require more vigilance. Consumer advocates must pay a great deal of attention to the details of MRP designs, which will have important implications for customers. Consequently, consumer advocates may need to develop a different set of skills to be able to effectively participate in the design of MRPs.

Consumer advocates may need to develop a different set of skills to be able to effectively participate in the design of MRPs.

ARM Design

The incentive power of an MRP depends crucially on its ability to reduce the frequency of rate cases and on its reliance on ARMs rather than trackers to address most costs. ARMs can also play an important role in ensuring that benefits from MRPs flow through to customers. ARM design is thus a key issue in a proceeding to approve an MRP. Four approaches to ARM design are well-established: forecasts, indexing, freezes, and hybrids of these approaches.

Forecasts

A forecast-based ARM bases rate adjustments primarily on multi-year forecasts. In the United States, ARMs based on cost forecasts typically increase revenue by a certain predetermined percentage in each year of the plan. This gives allowed rates or revenue a stair-step trajectory.[35] Stair-step ARMs are popular in the United States and are currently used by electric utilities in California, Georgia, North Dakota and New York.[36]

The forecast approach to ARM design has some advantages for electric utilities under today's business conditions. Many commissions are already engaged in integrated, multi-year planning exercises, such as integrated resource planning and the integrated distribution planning underway in California. These exercises reduce the incremental cost of developing stair-step ARMs based on cost forecasts.

On the other hand, regulators and intervenors in some states have shown a reluctance to sign off on multi-year cost forecasts. Furthermore, a multi-year forecast of total cost must consider numerous costs (e.g., distribution line maintenance) that are not closely related to DER and smart grid strategies. Since it is difficult to ascertain the value to customers that is implicit in a cost forecast, regulators in some countries, including Australia, Canada and Britain, have felt the need for costly engineering and benchmarking studies before signing off on ARMs based on forecasts.[37]

Indexing

An indexed ARM is developed using industry cost trend research. The following general formula drawn from cost theory is useful in the design of revenue caps for utility distribution companies:

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35 Stair-step ARMs in the United States are not always based on multi-year forecasts of all costs, however. In California, for example, the capex budget may be set for several years at the level approved for a forward test year used in the utility's general rate case.

36 California Public Utilities Commission (2014); Georgia Public Service Commission (2013); North Dakota Public Service Commission (2014); New York Public Service Commission (2015).

37 Ofgem (2014); Australian Energy Regulator (2015); and Research Team from the Australian Energy Regulator and the Regulatory Development Branch of the Australian Competition and Consumer Commission (2012).

growth Cost = growth Input Prices – growth Productivity + growth Customers

This provides the basis for the following revenue cap index:

growth Revenue = Inflation – X + growth Customers

where a recent measure of inflation such as a gross domestic product price index is used. Revenue growth would be slow in a period like the present that features slow input price inflation but would accelerate with rising inflation. *X*, the "productivity" or "X" factor, reflects the average productivity trend of a group of distributors. ARM escalation therefore reflects normal productivity growth, to the benefit of customers. A "stretch factor" (aka consumer dividend) is often added to *X* to share with customers the benefit of the stronger performance incentives expected under the plan.

Broad regional or national peer groups are commonly used to establish the base productivity trend. The peer group can in principle be customized to mirror special circumstances of the subject utility. For a utility needing accelerated system modernization, for instance, *X* could reflect the productivity trend of utilities that have previously faced this challenge.

The indexing approach to ARM design was developed in the United States.[38] It is currently used by the Federal Energy Regulation Commission to regulate U.S. oil pipelines and several smaller energy utilities and is also widely used in Canada and countries overseas, including New Zealand. United States energy utilities that previously operated under indexed ARMs include Bay State Gas, Boston Gas, Central Maine Power, San Diego Gas & Electric, Southern California Gas and NSTAR Electric.

Hybrids

A hybrid approach to ARM design uses a combination of methods. In the United States, a hybrid approach is used in which revenue that addresses utility opex is indexed, while revenue that addresses capital cost has a stair-step trajectory. This approach to ARM design was developed in California and has been used several times there.[39] Hybrid ARMs have recently been used in MRPs of Hawaiian Electric and Southern California Edison.

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends on growth in billing determinants and tracked costs. Freezes usually apply only to base rates but sometimes apply to rates for commodity procurement.[40] Rate freezes are compensatory for utilities when growth in their net cost of service matches or is slower than the growth in their billing determinants. Such favorable operating conditions have occurred over the years under special circumstances in the electric industry. For example:

- Electric utilities in the early postwar period experienced rapid growth in productivity and system use and slow inflation.

[38] Early American papers encouraging the use of input price and productivity research in ARM design include Sudit (1979) and Baumol (1982).

[39] Early approvals of hybrid ARMs included the 1985 CPUC decisions for most of the large California energy utilities.

[40] Comnes, Stoft, Greene and Hill (1995).

- Following major generating plant additions in the 1980s and early 1990s, some vertically integrated utilities experienced unusually slow cost growth due to slow inflation and declining generation rate bases. Several U.S. vertically integrated utilities operated without rate cases for more than 15 years.[41]
- Mergers and acquisitions facilitate rate freeze agreements by creating special cost containment opportunities.

Favorable circumstances like these are less common today. Utility distribution companies cannot benefit from declining generation rate bases. Some utilities need high capex for accelerated system modernization, increased resiliency, cleaner generation, or a combination of these factors. There is typically little sales volume growth between rate cases available to finance cost growth. Nonetheless, rate freezes have recently been approved for several U.S. electric utilities.[42] These are typically vertically integrated utilities with limited need to increase generation rate base. Provided that a few costs that are growing are tracked, they do not need any further rate escalation for several years. For vertically integrated utilities the tracked cost usually includes the cost of generating plant additions.

Rate freezes can maintain or exacerbate a utility's throughput incentive, and can therefore create a disincentive to DERs. This concern can be addressed by implementing revenue regulation. Under an MRP with revenue regulation but with no ARM, the utility would be subject to a "revenue freeze," instead of a rate freeze, and would therefore not be harmed by lost revenues from DER. This could also be taken a step further by establishing an ARM that escalates allowed revenue only for customer growth, producing a "revenue per customer freeze."

Role of Benchmarking

Statistical benchmarking can be helpful in ARM design using all of these approaches. The Ontario Energy Board, for example, regulates most power distributors with MRPs featuring price cap indexes of "inflation – X" form.[43] The X factor is based in part on the trend in the productivity of Ontario utility distribution companies and in part on stretch factors derived from a Board-commissioned econometric benchmarking study. The Board also permits "custom" MRPs but requires that their ARMs be designed using benchmarking and productivity research.[44]

MRP Precedents

In North America, the use of MRPs began on a large scale in the 1980s. MRPs have been especially popular where utilities have a special need for marketing flexibility. Such plans have helped railroads, oil pipelines, and telecom utilities serve markets with diverse competitive pressures and complex and changing customer needs. For example, telecom utilities were given a freer hand to offer competitive rates to customers in central business districts, where competition was greatest, and to offer value-added (aka discretionary) services, such as caller ID, that make use of new digital technologies. Rates for standard services to residential customers were insensitive to such initiatives. For example, most telecom plans featured index-based price caps that separately escalated the prices of several groups of

[41] Vertically integrated utilities that went more than 15 years between rate cases during this era included Florida Power & Light, Indianapolis Power & Light, and Carolina Power & Light.
[42] These include Appalachian Power, Arizona Public Service, Dominion Virginia and Public Service of Colorado.
[43] Ontario Energy Board (2013).
[44] Ontario Energy Board (2012).

services (aka “baskets”) and did not include earnings sharing. Rates for basic residential services were often frozen.

Under ratemaking reforms in the Staggers Rail Act of 1980, which included MRPs, U.S. railroads were also granted increased marketing flexibility. They used this flexibility to address intermodal competition from truckers and waterborne carriers, manage their costs better, and meet special customer needs. Lower rates were offered to customers making less costly service requests. For example, lower rates were offered for unit trains and pickups (and drop-offs) along high traffic corridors.[45]

In the U.S. electric utility industry, MRPs were first used extensively in California, where a Rate Case Plan was established in the 1980s that, with modifications, has limited the frequency of general rate cases to this day.[46] Iowa, Maine, Massachusetts and New York have also been MRP innovators. An MRP for Central Maine Power afforded the company considerable flexibility in marketing to price-sensitive paper mill customers.[47] MidAmerican Energy operated under a lengthy rate freeze that extended to its energy costs but permitted the company to keep margins from its off-system sales.[48] The use of MRPs in the United States has recently spread to vertically integrated utilities in a diverse collection of other states that includes Colorado, Florida, Georgia, Virginia and Washington.[49]

In Canada, MRPs are becoming mandatory for natural gas and electric power distributors in the four most populous provinces. Ontario, which regulates more than 70 power distributors, is now on its fourth generation of MRPs for these utilities. Overseas, the privatization of many energy utilities in the last 25 years has forced governments to reconsider their approach to regulation. The majority has chosen MRPs over COSR. Regulators in Australia, Britain, Germany, the Netherlands and New Zealand are MRP leaders.

An indication of the potential incentive impact of MRPs can be found in the experience of Central Maine Power, which operated under three successive MRPs (called “Alternative Rate Plans”) from 1995 to 2013. Figure 2 compares the trend in the multifactor productivity of the power distributor services of Central Maine Power to those of other distributors in the mid-Atlantic and northeast United States since the mid-1990s.[50]

Figure 2 shows that the company attained productivity growth well above the industry norms in the northeast United States during these years. This was accomplished primarily through superior capital productivity growth. The MRPs seem to have encouraged Central Maine Power to slow its rate base growth.[51]

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45 Railroads today operate under a different form of regulation in which most rates and services are deregulated but shippers can contest rates where competition is limited and request rates based on benchmarks or rough estimates of the stand-alone cost of service provision. This regulatory system has given railroads the flexibility and incentive to make complex and changing rates and service offerings in competitive markets. One manifestation of this flexibility has been their recent success in capturing a sizable share of the traffic from new oilfield developments.

46 California Public Utilities Commission (1985).

47 Maine Public Utilities Commission (1995).

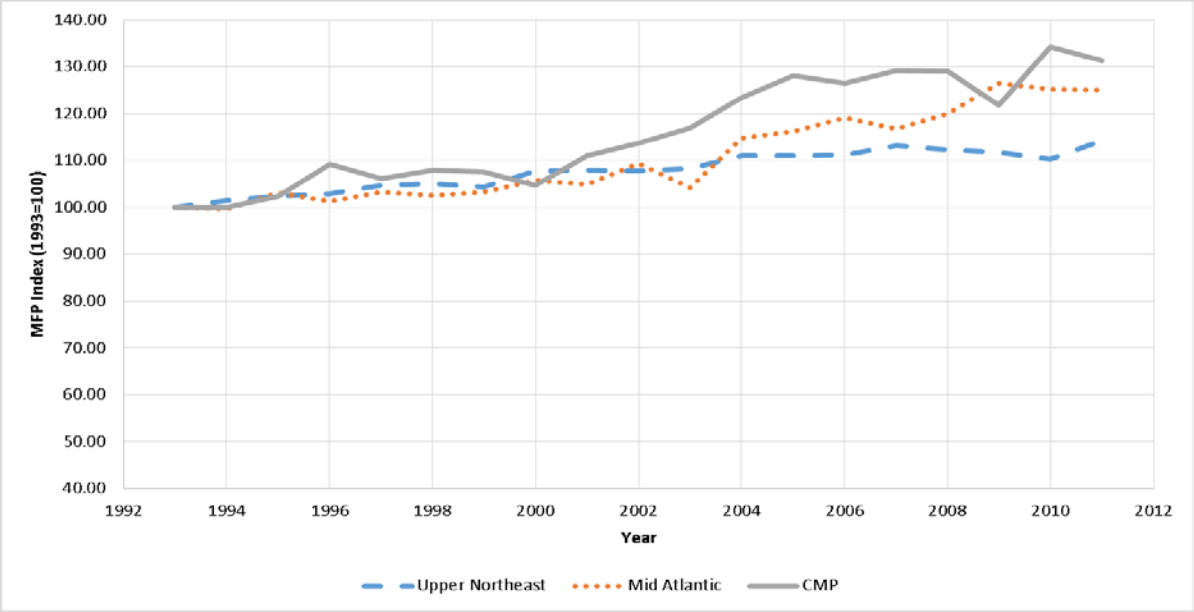
48 Iowa Utilities Board (1997); Iowa Utilities Board (2001); and Iowa Utilities Board (2003).

49 Colorado Public Utilities Commission (2012); Florida Public Service Commission (2013); Georgia Public Service Commission 2010; and North Dakota Public Utilities Commission (2014).

50 Lowry (2013).

51 At the end of the rate period indicated in Figure 2, CMP made a request for an MRP that would have significantly increased its revenue to allow for new capital expenditures. The CMP rate case was eventually settled, with a stipulation to terminate PBR in Maine and return to a system more akin to COSR. Maine Public Utilities Commission (2014).

Figure 2. Distribution Productivity Trends of Central Maine Power and Two Peer Groups



The superiority of multifactor productivity growth in the Mid-Atlantic states to those in the upper Northeast (New York and New England) is also noteworthy, since several of the best-performing Mid-Atlantic utilities operated under lengthy rate freezes with no earnings sharing. Statistical benchmarking studies by PEG Research have, similarly, shown that vertically integrated electric utilities that have operated for long periods without rate cases often display superior cost management.

2.6. British RIIO System as an Example of Comprehensive PBR

For more than 25 years, Great Britain has used MRPs (called "price controls") to regulate its electric utilities. Each utility's revenue requirement forecast during the five-year rate period provided the basis for an inflation – X escalator (referred to as "RPI-X"). The MRP scheme has evolved continually over the years. For example, the plans have in recent years featured a broader array of PIMs.

In 2008 the British Office of Gas and Electricity Markets ("Ofgem") launched a fundamental review of the regulatory framework. The review found that the traditional PBR approach was no longer well-suited to meet changing policy priorities and industry challenges. While PBR provided incentives to reduce costs, the five-year term was found to be too brief to encourage utilities to make highly innovative investments with longer-term payback periods. Further, the regulatory model gave utilities little incentive to pursue policy objectives other than cost control and service quality maintenance. Finally, the RPI-X approach was found to be too inflexible to effectively accommodate step-changes in technology.

Out of this review and stakeholder discussion was born a revised, more comprehensive and performance-based form of MRP. This new framework is referred to as "RIIO," an abbreviation for Revenue = Incentives + Innovation + Outputs.

Key elements of RIIO include:

- *Rate case moratorium.* The rate period has been extended to eight years in order to provide greater innovation incentives by allowing the utilities to retain the cost savings for a longer period of time.

- *Base revenues, attrition relief mechanism and capital expenditures.* The utility's allowed revenues for each year of the rate plan are based on the total cost forecast in a regulator-approved business plan for each utility. A rate of return is earned on a certain percentage of the total expenditures, rather than specifically on capital investments.

- *Greater focus on PIMs.* A larger proportion of the utility's revenues are tied to PIMs.

Below we describe these elements, the rationale for each and key challenges.

Rate Case Moratorium

Prior to RIIO, electric utilities in Great Britain were regulated under five-year price control plans. However, the five-year duration was deemed inadequate for encouraging the utilities to focus on long-term initiatives to reduce costs and enhance service quality, or to experiment with innovative strategies and technologies. For this reason, RIIO has eight-year plan periods, with only limited opportunity to modify allowed revenues through "reopeners." That is, only in cases of significant changes to input costs or government regulations will the utilities be able to request modifications to base revenues. In this manner, RIIO attempts to retain strong cost control incentives and a focus on long-term investments, while providing a safety valve to accommodate uncertainty regarding the future.

Base Revenues, Attrition Relief Mechanism and Capital Investments

RIIO continues the reliance on multi-year forecasts of utility cost (referred to as "business plans") to design ARMs. Revenue requirements are later adjusted for inflation. Some innovative methods are used in revenue requirement determination.

Business plans: Revenue requirements under RIIO are set based on eight-year utility business plans. Requirements are established in real terms and then escalated for inflation. Because the business plan plays such a critical role in determining utility revenues, substantial effort is made to ensure that the plans are thorough, realistic and appropriately justified. Business plans must demonstrate that the utility will provide sufficient "value for money" to customers through pursuing efficiencies and delivering on the six categories of additional "outputs" described in the next section. In developing their business plans, utilities are also required to assess alternative options for delivering outputs, evaluate the long-term costs and benefits for each alternative, and incorporate stakeholder input.

The plans undergo significant scrutiny from regulators, who use statistical benchmarking and independent engineering analysis to determine whether the costs included in the plans are reasonable. Revenue requirements are based 75 percent on Ofgem's assessment and 25 percent on the utility's cost forecast. Once approved, the business plans form the basis for revenue adjustments over the rate period. Following are two key components of the business plan process:

- *Fast Track.* A utility that submits a business plan that Ofgem deems of sufficiently high quality in its initial assessment can receive "fast-track" treatment.[52] Fast-tracked utilities in the first round of RIIO for power distributors finished the majority of the proceeding a year ahead of the remaining utilities.
- *Information Quality Incentive.* To encourage utilities to provide honest assessments of their future costs, an Information Quality Incentive (IQI) mechanism is used. The IQI has three features: it finalizes the revenue requirement, determines the sharing of variances between actual and forecasted cost, and provides an immediate reward or penalty based on the reasonableness of the company's forecast.

In the spirit of work by Nobel prize-winning economist Jean Tirole, the IQI also functions as an incentive-compatible menu.[53] In such a menu, a utility can choose from among several combinations of ratemaking provisions, such as revenue and earnings sharing factors. The menu is designed so that the utility, by its choice, reveals the cost that it can achieve, thereby overcoming information asymmetry. For example, a utility that requests a lower level of revenues (more closely matching Ofgem's assessment of efficient costs) would be rewarded with additional income and a greater portion of any savings relative to allowed cost. A utility is also rewarded when its actual cost is similar to its forecast. In contrast, a utility that requests a higher level of revenue (that exceeds Ofgem's estimate of efficient cost) would be required to pass on a higher percentage of surplus earnings to customers and receive an initial penalty.

Totex: Under RIIO, capital and operating expenditures are combined into one category: "total expenditures," or "totex," in determining revenue requirements. The utility is afforded a return on a predetermined percentage of totex, regardless of whether the utility's capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus noncapital projects.

Performance Incentive Mechanisms

Under RIIO, PIMs take on a larger role. Whereas early PBR plans incorporated service quality standards into plans to guard against service degradation, RIIO employs PIMs to proactively guide the utility in its actions in order to achieve a broader array of policy objectives. These objectives are grouped into six "output" categories:

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52 Ofgem's initial assessment reviewed the business plans according to five broad criteria: process, outputs, efficient expenditure, efficient finance, and uncertainty and risk. The process criteria focused on the clarity of the business plans, the extent of stakeholder input in the plan, and whether or not the plan seemed reasonable overall. The outputs criteria explored whether or not the business plan complied with the strategy decision on outputs. Efficient expenditure encompassed benchmarking of total expenditures (totex) and whether a utility had justified its expenditures given the level of outputs and reviewed possible alternatives. Efficient financing reviewed the utility's compliance with the strategy decision, its consistency with past practice, and the justification of the company's financing plan. Uncertainty and risk measured the business plan's clarity on the uncertainty and risk that it faces and the mitigation efforts proposed.

53 See Laffont and Tirole (1993).

1. Safe network services
2. Environmental impact
3. Customer satisfaction
4. Social obligations
5. Connections
6. Reliability and availability

Each of the six primary output categories contain a set of "secondary deliverables" defined by specific metrics. Targets for some deliverables are set by Ofgem with input from stakeholders, while targets for other deliverables (such as asset health) are proposed by the utilities themselves in their business plans. All targets proposed by utilities must be justified in terms of costs and benefits to customers and informed by stakeholder engagement.[54]

However, not all outputs under RIIO have financial incentives. For example, the Reliability and Safety Working Group rejected the use of incentives (financial or reputational) for safety, as it was felt they could result in unwanted implications for incident reporting. Moreover, utilities are already required to comply with health and safety standards set by another governmental agency and would be subject to enforcement action from that agency in the event of noncompliance.[55]

The PIMs in RIIO place a larger amount of revenues at stake than is common in North American MRPs. The results of Ofgem's modeling suggest that actual power distributor ROEs may range from approximately 2 percent to more than 10 percent, depending on how well the utilities achieve their targets.[56] A significant portion of this variability is due to the IQI, which is used to determine the utility's allowed revenues, as discussed above.

The magnitude by which utility earnings can fluctuate under RIIO highlights the importance of developing metrics and targets carefully. Setting a target too low could easily result in excessive earnings, while setting a target too high could jeopardize the financial health of the company, also resulting in negative impacts on ratepayers. Stakeholder involvement in setting metrics and targets is critical for reducing contention in later proceedings and helping to ensure that targets are immune from gaming. Stakeholders must be confident that positive financial incentives were justly earned in order to reduce the possibility that such earnings will be taken away from the utility, thereby undermining the incentives embedded in the plan.

Choosing objective metrics and setting targets at an appropriate level are not easy tasks, however. After several years of stakeholder consultations, several metrics have yet to be fully specified, while others (such as environmental impacts) are not yet mature enough to attach financial incentives.

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[54] Ofgem (2012).
[55] *Id.*
[56] Ofgem (2014).

Role of RIIO in a High DER Future

RIIO is often cited as a potential model for regulating the "utility of the future."[57] In general, there is a call for new regulatory models that are more focused on performance, outputs, and outcomes, and less focused on regulatory review of utility investments after the fact.

The RIIO model offers several components that appear to provide better utility incentives relative to those provided by COSR. An MRP with an eight-year plan term provides strong cost containment incentives. Incorporating a comprehensive set of PIMs might provide utilities with more direction and incentive to adopt evolving technologies, including DERs. Setting allowed revenues based on long-term business plans might help utilities plan for and make investments in new technologies such as smart grid. Use of the "totex" method for earning a rate of return might reduce the utility's incentive to invest in large capital projects.

The RIIO model offers several components that appear to provide better utility incentives relative to those provided by COSR.

On the other hand, RIIO includes a highly complex and expensive approach to MRP design, with considerable risk for both utilities and consumers, due in part to the eight-year term between rate cases. Lessons the United States can learn from RIIO are discussed further in Chapter 5.

57 See, for example, Lehr (2013); Binz and Mullen (2012); and Spiegel-Feld and Mandel (2015).

3. Regulatory Considerations Regarding PBR

There are several issues that regulators and stakeholders should investigate when deciding whether and how to implement some form of PBR. For example:

A. Does the existing regulatory framework provide appropriate utility incentives in a high DER future?

Regulators and stakeholders should begin by assessing the history and experience with the current regulatory framework in their state. Does the existing framework provide appropriate guidance, incentives, operating flexibility, and a fair opportunity for recovery of efficient costs for utilities at reasonable regulatory cost in a high DER future? How well does the existing regulatory framework support state energy policy goals, particularly goals related to DERs?

B. To what extent should regulators and other stakeholders guide outcomes?

Relative to COSR, PBR allows regulators to provide more guidance on desired outcomes. When considering whether and how to implement PBR in a high DER future, regulators and stakeholders should consider how much regulatory guidance utilities will need. MRPs provide utilities with guidance on the general performance areas related to operational efficiency and reduced costs, while the decisions for how to achieve improved performance are left to the utility. PIMs, on the other hand, typically provide utilities with much more focused regulatory guidance on specific performance areas and goals.

C. To what extent should utilities be provided with flexibility and regulatory certainty?

In a high DER future, utilities may need more flexibility than is available under COSR to quickly respond to emerging technologies and evolving customer needs. On the other hand, utilities typically prefer to have some regulatory certainty regarding the ability to recover investments in innovative or unconventional technologies and resources. When considering whether and how to implement PBR in a high DER future, regulators and stakeholders should consider how much guidance utilities need before making investments in innovative initiatives and how much certainty they need with regard to recovering those investments.

D. What are the various PBR options available?

As described in Chapter 2, there are a variety of PBR elements that can be used in different combinations. Which elements are most appropriate for the particular jurisdiction? What mix of PBR tools make sense for utilities and jurisdictions in different industry contexts? For example, are MRPs preferable to stand-alone PIMs?

E. What are the key PBR design issues?

How should PBR mechanisms be designed to achieve the ultimate goal of improved utility performance? Which of the PBR elements described in Chapter 2 have proven to be most effective in the past? Would it be best to implement a mix of multiple PBR elements (such as MRPs with cost trackers and PIMs)? Which specific PBR design issues are more relevant in a high DER future?

F. Will PBR provide the best outcome for customers?

Will PBR provide overall benefits to customers, relative to the existing regulatory framework? Will the operational efficiencies, cost reductions, and other benefits be shared with customers? Will PBR increase customer risk and, if so, are there countervailing benefits? How should regulators balance risks between utilities and their customers? Will PBR create opportunities for utilities to manipulate the mechanism or game the results in any way?

4. Criteria for Evaluating PBR

A move to PBR is worthwhile when it yields greater net benefits than COSR and shares these benefits fairly among stakeholders in the regulatory process. As described above, the potential benefits of PBR include improved utility operating performance due to stronger performance incentives and increased operating flexibility (including marketing flexibility, where this is deemed necessary while protecting customers from any untoward consequences). The performance dimensions that matter most to customers include the cost and quality of service. Other potential benefits include fewer negative externalities from utility operations and a more efficient regulatory process. Possible costs of PBR include greater operating risk and an unfair allocation of the costs and benefits between utilities and other stakeholders.

To determine whether PBR is achieving its objectives, PBR can be evaluated according to responses to the following questions:

Operating Performance

Cost

- Does PBR encourage better cost performance?
  - Is there improved attentiveness to cost containment?
  - Have environmental costs been reduced?
  - Has the utility embraced DERs as cost containment tools?
  - Are new technologies being used appropriately?
  - Is outsourcing of certain utility functions being done where appropriate?
  - Is the utility facilitating third-party roles — e.g., in market development?

Quality

- Does PBR encourage optimal reliability and customer service quality, including service to customers with on-site generation and storage?

Market Effectiveness

- Does PBR encourage utilities to offer the right mix of rates and services? For example:
  - Is the utility developing tariffs that send the right price signals to customers?
  - Is the utility promoting efficient use of power in clean energy applications (e.g., EVs)?
  - Is the utility providing a market-responsive array of grid-supplied clean power alternatives?
  - Is uneconomic bypass being successfully avoided?

- Is the utility offering value-added services made possible by new technologies?
- Is the utility providing grid services that support new markets?

Efficiency of Regulation

- Has regulation been streamlined where possible so that resources can be redeployed to more valuable uses (such as integrated resource planning and other non-rate-case proceedings)?

Risk

- Does PBR involve excessive or undue risk to utilities?
- Does PBR involve excessive or undue risk to customers?
- Is the allowed rate of return under PBR commensurate with operating risk?

Distribution of Benefits

- Do utilities have a reasonable opportunity to recover their efficient cost of service?
- Are the net benefits of performance improvements fairly distributed? For example, is a superior (inferior) performer likely to earn a superior (inferior) return? Can utilities keep some of the benefits from the lasting improvements in performance that they achieve?
- Is regulatory capture of the process by utilities avoided?

5. Perspectives on PBR Issues

As illustrated in the previous chapters, PBR is comprised of numerous elements, each of which offers opportunities as well as risks. These opportunities and risks are often different for the various stakeholders in the regulatory process. To highlight some of these differences, this chapter examines key PBR elements and different approaches to PBR implementation from the perspectives of two key groups: consumers and utilities.

In practice, the utility perspective is not necessarily in direct opposition to that of consumers. Nevertheless, the simplified perspectives below may be helpful for illustrating, in general terms, how different aspects of PBR tend to be viewed by the two groups.

Regulators have a unique perspective, in that they must balance the interests of consumers and utilities with the goal of achieving a result that is in the overall public interest. In many cases, regulators are also tasked with considering additional issues such as environmental protection, and additional perspectives such as those of competitive suppliers, third-party vendors and other elements of the electricity industry. We expect regulators would consider both utility and consumer perspectives outlined here, and we offer summaries of the advantages and disadvantages that may be most pertinent to regulators.

Regulators have a unique perspective, in that they must balance the interests of consumers and utilities with the goal of achieving a result that is in the overall public interest.

This chapter is organized into four sections, covering MRPs, PIMs, MRPs versus stand-alone PIMs, and lessons the United States can learn from Great Britain's RIIO approach. Each of these sections discusses advantages and disadvantages from the customers' perspective, followed by the utility's perspective. The organizational structure is displayed in the boxes below.

5.1 MRPs

- 5.1.1 **Customers' Perspective** (Advantages & Disadvantage)
  - Overarching Issues
  - Attrition Relief Mechanisms
- 5.1.2 **Utility's Perspective** (Advantages & Disadvantage)
  - Overarching Issues
  - Attrition Relief Mechanisms

5.2 PIMs

- 5.2.1 **Customers' Perspective** (Advantages & Disadvantage)
  - Overarching Issues
  - Metrics and Targets
  - Financial Incentives
- 5.2.2 **Utility's Perspective** (Advantages & Disadvantage)
  - Overarching Issues
  - Metrics and Targets
  - Financial Incentives

5.3 MRPs vs. Stand-Alone PIMs

- 5.3.1 **Customers' Perspective**
  - Arguments for Stand-Alone PIMs
  - Arguments for MRPs
- 5.3.2 **Utility's Perspective**
  - Arguments for Stand-Alone PIMs
  - Arguments for MRPs

5.4 What Can the United States Learn From the British Approach to PBR?

- 5.4.1 **Customers' Perspective**
  - Advantages of RIIO
  - Disadvantages of RIIO
  - Other Approaches to PBR
- 5.4.2 **Utility's Perspective**
  - Advantages of RIIO
  - Disadvantages of RIIO

5.1. Multi-Year Rate Plans

Multi-year rate plans have been used for decades to provide utilities with strong cost control incentives, while streamlining regulation and facilitating utility innovation and marketing flexibility. However, MRPs can pose risks for utilities as well as for regulators and customers. This section considers both the advantages and disadvantages associated with MRPs in general, and takes a close look at the ARM provisions.

5.1.1 Customers' Perspective

Overarching Issues With MRPs

<u>Advantages of MRPs From the Customers' Perspective</u>

From the perspective of consumers, MRPs can potentially offer a host of benefits, including reduced costs, greater implementation of DERs, and more transparency regarding utility cost performance.

MRPs have the potential to deliver significant cost savings to customers. By capping utilities' allowed revenues and allowing utilities to keep a portion of cost savings, MRPs can provide financial incentives to encourage utilities to undertake a wide range of initiatives to improve performance. In other words, MRPs typically increase regulatory lag (the lag between an increase in a utility's cost and an adjustment to revenue for that cost increase) without sacrificing the timeliness of rate adjustments. These cost control incentives can also help to shift utility financial incentives away from the bias toward capital investments and increasing rate base that exists under COSR.

MRPs can streamline regulation. A widely recognized benefit of MRPs is the potential for fewer rate cases, since MRPs typically span three or more years. Fewer rate cases can free up time for regulators and stakeholders to spend on other important proceedings. In a high DER future, important proceedings are needed on numerous topics including integrated resource planning and the value of distributed solar power. The benefit of regulatory cost savings is greatest in jurisdictions with numerous utilities. In the United States, jurisdictions with four or more investor-owned electric utilities include California, Florida, Indiana, Missouri, New York, Ohio, Pennsylvania, Texas and Wisconsin. Another way that MRPs can reduce costs is by reducing the need for regulatory review of specific utility initiatives or capital expenditures after they have been made, since the MRP strongly incentivizes cost containment.

THE REGULATORS' PERSPECTIVE

Regulator interests frequently overlap with customer and utility interests. Here we highlight several advantages and disadvantages that may be especially pertinent to regulators.

<u>Advantages of MRPs</u>

- Can reduce the frequency of rate cases, freeing up commission resources for other needs
- Can improve the culture of utility management
- Can improve utility performance and lower utility costs
- ARMs used with MRPs typically result in predictable, stable rate increases, relative to rate cases

<u>Disadvantages of MRPs</u>

- Challenging to design ARMs in a way that balances customer and utility interests
- Fewer rate cases means less frequent opportunities to review costs
- Commission may lack resources and skills to effectively review proposals
- Utilities tend to have an advantage in terms of access to information

MRPs can provide financial incentives to encourage utilities to undertake a wide range of initiatives to improve performance. In other words, MRPs typically increase regulatory lag (the lag between an increase in a utility's cost and an adjustment to revenue for that cost increase) without sacrificing the timeliness of rate adjustments. These cost control incentives can also help to shift utility financial incentives away from the bias toward capital investments and increasing rate base that exists under COSR.

MRPs can change the culture of utility management by creating an increased focus on opportunities to reduce cost and improve long-term performance, as well as an increased awareness of how their performance compares to those of peer utilities. This cultural change could ultimately benefit consumers through improved utility performance.

Several MRP design options can ensure that the cost savings stemming from improved utility performance are shared between utilities and their customers. These options include earnings sharing mechanisms, the occasional rate cases, and the stretch factor provisions of ARMs.

Another benefit of MRPs is that they can be used to encourage the implementation of cost-effective DERs. To achieve this benefit, MRPs must be properly and comprehensively designed to: (a) strengthen the utility's incentive to contain capital expenditures; (b) include revenue regulation to offset a utility's throughput incentive; (c) allow for timely recovery of utility DER-related costs (such as energy efficiency and demand response program costs and distributed generation integration costs); and (d) include DER-focused PIMs.

The issues and information regarding utility cost efficiency and productivity growth which frequently arise in MRP proceedings can assist regulators and stakeholders in better understanding and overseeing utility performance and behavior. Regulators can use that information to better ensure that rates reflect normal or superior levels of operating efficiency.

MRPs can be adopted in stages to gradually build experience, reducing regulatory risk. For example, a number of U.S. regulators have recently experimented with plans with only two- or three-year terms. Simplified approaches to ARM design are also available.

<u>Disadvantages of MRPs From the Customers' Perspective</u>

Despite these benefits, MRPs present several potential drawbacks. For example, there is a risk that an MRP will result in a utility's revenues exceeding its costs for extended periods of time. While such an outcome might be accompanied by improvements in long-term performance and cost reductions, some customers (and regulators) may be reluctant to accept this risk.

Despite these benefits, MRPs present several potential drawbacks.

The risk of an adverse outcome may be particularly acute where regulators and consumer advocates lack the expertise and funding that are needed to advocate effectively on technical MRP design issues.

Utilities, on the other hand, have funding to obtain the requisite expertise, thereby creating a risk of "regulatory capture" of the MRP process by utilities.

Well-designed index-based ARMs can provide customers with the benefits of productivity growth that exceeds industry standards.

Another issue of concern is that MRPs typically produce steady (i.e., annual) increases in customer base rates, unlike COSR where customer base rates do not increase between rate cases. Although there are several mechanisms that can help protect consumers under an MRP — such as earnings sharing mechanisms, off ramps, consumer dividends and shorter rate plan periods — most of these mechanisms weaken the key incentives provided by MRPs to increase efficiencies and reduce costs.

MRPs typically result in less frequent rate cases. While this may be considered an advantage in terms of streamlining regulation, it may also be considered a disadvantage by consumer advocates (and regulators) who prefer to investigate utility costs and rates on a more frequent basis. In addition, less frequent rate cases can increase the regulatory costs of the rate cases that do occur. This may be necessary to allow for thorough review of proposals for ARMs, cost trackers, ESMs and other MRP provisions.

Attrition Relief Mechanisms

Forecast-based ARMs allow more regulatory guidance prior to investments by utilizing a forecast of specific capital expenditures.

Advantages of ARMs From the Customers' Perspective

ARMs are an important source of stronger performance incentives in MRPs. Well-designed index-based ARMs can provide customers with the benefits of productivity growth that exceeds industry standards. External productivity growth standards can simulate competitive market pressures and foster better utility management. Forecast-based ARMs allow more regulatory guidance prior to investments by utilizing a forecast of specific capital expenditures.

Forecast-based ARMs can include expenditures needed to support DERs (e.g., distribution grid investments needed to support distributed generation). This could significantly encourage the implementation of DERs by providing regulatory guidance and approval for these investments.

Disadvantages of ARMs From the Customers' Perspective

ARMs are one of the most challenging aspects of an MRP to design in a way that balances the interests of customers and utilities, since regulators and other stakeholders do not have perfect information regarding the utility's efficient level of costs. This is true for both index-based and forecast-based ARMs, for the reasons described below.

Index-based ARMs are typically constructed using estimates of productivity trends for utility peer groups. It can be challenging to identify a set of peers that experienced capital expenditure needs and other cost pressures in a recent historical period that match those that the subject utility will face prospectively. In addition, productivity research can be opaque and complex, and the large dollar stakes encourage controversy. The regulatory cost of developing an index-based ARM can therefore be considerable.

On the other hand, the cost of developing an index-based ARM can be lower than that of developing forecast-based ARMs. Several regulators have grappled with these issues, yielding a fairly narrow range of approved productivity growth targets in North American proceedings. Simplified approaches to X factor calculation such as the "Kahn method" used by FERC in interstate pipeline proceedings are available.[58]

Index-based ARMs cannot easily accommodate occasional, large capital spending surges such as replacement of customer information systems or a system-wide buildout of advanced metering infrastructure. Thus, the utility might postpone some investments that would be beneficial to customers. Capital cost trackers can remedy this problem, but these trackers reduce incentives to contain costs and can pose risks to customers. Furthermore, regulators and consumer advocates are often uncomfortable signing off on proposals for such large capital spending surges in the context of an ARM, and in the absence of a rate case.

Forecast-based ARMs require a broad review of future costs, including capital expenditures and operating costs, and these are hard to predict in an era of aging assets and technological change. Utilities generally have the advantage of information and resources. The scope of required forecasts can be reduced by escalating the budgets for some costs using formulas.

Forecast-based ARMs mean that future capital expenditures in the cost forecast are effectively preapproved.

Forecast-based ARMs mean that future capital expenditures in the cost forecast are effectively preapproved.[59] This represents a fundamental change in regulatory responsibility for some states and shifts some investment decision risk to customers. Regulators and stakeholders will need sufficient resources, capabilities, and regulatory processes to sufficiently review the cost forecasts in order to protect customers.

Proceedings to approve forecast-based ARMs can be controversial and contentious. Some remedies for this problem, such as earnings sharing mechanisms and the return to customers of capex underspends, weaken cost containment incentives. Another remedy, extensive commission use of engineering and statistical cost research, involves high regulatory cost. Table 5 summarizes the advantages and disadvantages of MRPs from the customers' perspective.

[58] The Kahn method calculates X factors based on cost trends and does not require calculation of input price and productivity indexes. See FERC (2015), Notice of Inquiry, *Five Year Review of the Oil Pipeline Index*, Docket No. RM15-20-000, June 30.

[59] Utilities would still be at risk for how they performed with regard to the development of the approved capital project, particularly the ultimate cost of developing the project.

Table 5. Multi-Year Rate Plans From the Customers' Perspective

Advantages	Improved utility performance and lower utility costs Benefits can be shared with customers Less frequent rate cases may permit more attention to other important issues May improve information transparency regarding utility performance Can encourage implementation of cost-effective DERs Can be implemented gradually
Disadvantages	Typically results in automatic rate increases Revenue may exceed cost for extended periods Fewer rate cases means less frequent opportunities to review costs ARM design methods can be opaque, complex and controversial Stakeholders may lack resources and skills to effectively protect consumers

5.1.2 Utility's Perspective

Overarching Issues With MRPs

Advantages of MRPs From the Utility's Perspective

MRPs provide more opportunities for utilities to bolster earnings from improved cost containment and marketing. Greater marketing flexibility is needed today to retain large customers and satisfy the complex, changing demands of customers. As discussed in Section 2.5, the need for marketing flexibility is growing due to increased competition and technological change. For example, there is an increasing need for utilities to have the flexibility to offer customers products related to electric vehicles, green power, and value-added services that might be provided using new metering and distribution technologies. A utility might, for example, wish to offer new green power options to customers that are considering alternative providers of electricity. Custom packages are already being offered by utilities for green power services to large volume "key account" customers.[60] A discounted base rate might be offered for electric vehicle charging when the price of gasoline is low. Utilities can take advantage of advanced metering infrastructure to offer more time-sensitive and location-specific rate options. Rate floors for offerings can alleviate concerns about predatory pricing and cross-subsidization.

MRPs permit superior performers to earn superior returns for a sustained period. The improved cost containment and marketing performance that can result from MRPs is especially welcome for utilities facing mounting competition and reduced opportunities for traditional investments.

MRPs permit superior performers to earn superior returns for a sustained period. The improved cost containment and marketing performance that can result from MRPs is especially welcome for utilities facing mounting competition and reduced opportunities for traditional investments.

60 See, for example, the Green Rider service of Duke Energy in North Carolina.

By reducing the frequency of rate cases, MRPs can also help utility managers focus on their basic business of providing customer-responsive services cost effectively. The more businesslike corporate culture that MRPs encourage can also help utilities succeed with mergers and acquisitions. Some of the most successful U.S. utility companies, including Duke Energy, NextEra Energy, and MidAmerican Energy, operated for many years without rate cases. Managers who spearhead performance improvements under the spur of stronger incentives have increased advancement prospects. Streamlined regulation is particularly valued by utility companies that operate in multiple jurisdictions. These companies are quite numerous in the United States today.

Utility operating risk may increase under MRPs. Thus, there is less risk of a reduction in the target ROE compared to other forms of alternative regulation, such as cost trackers and revenue decoupling. Utilities that combine proposals for an MRP and revenue decoupling reduce the risk of a reduction in authorized ROE.

Utilities can afford to purchase or develop the in-house expertise needed to develop sound MRP strategies and persuasive testimony. This reduces the likelihood of poor regulatory outcomes. Utilities can learn to master the MRP process much as they currently excel at the rate case process.

<u>Disadvantages of MRPs From the Utility's Perspective</u>

The increased risk of operation under MRPs is unlikely to be matched by an increase in the authorized ROE. One source of risk is that revenue will not always track the occasional surges in utility cost. Another is that MRPs may be designed in such a way that a competitive rate of return is impossible, or that customers receive most benefits of improved performance. Utilities in some countries have sued regulators for their MRP decisions or filed appeals in the court system.[61]

Another concern is that MRPs can increase the interest of regulators and consumer advocates in statistical benchmarking and industry productivity growth standards. It is difficult to benchmark performance accurately and establish appropriate productivity growth goals. Benchmarking is especially unwelcome for poorly performing utilities.

Companies that do not own multiple utilities or operate in multiple jurisdictions have less to gain from the streamlining of regulation.

Attrition Relief Mechanisms

<u>Advantages of ARMs From the Utility's Perspective</u>

Utilities benefit from the greater revenue growth predictability that ARMs generally provide. Forecast-based ARMs are the most widely used form of ARMs by U.S. electric utilities today. These ARMs can be tailored to fund anticipated capex surges.

Index-based ARMs have been advocated over the years by several North American energy utilities, as they typically provide reasonable revenue growth when high capex is not anticipated, and they can tailor revenue growth to actual inflation and customer growth.

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[61] See ATCO Group (2015); FortisAlberta (2015); Ausgrid, Endeavour Energy, and Essential Energy (2015); and Higgins (2015).

Disadvantages of ARMs From the Utility's Perspective

It can be difficult to design ARMs that address all cost surges that utilities experience. This is particularly true for index-based ARMs because they increase revenue according to an external index that typically reflects long-term productivity trends. While it may be possible for utilities to obtain supplemental revenue for such surges through capital cost trackers or other means, such requests will be resisted by some stakeholders and may be denied.

Forecast-based ARMs may also provide inadequate revenues for utilities, as it is difficult to accurately forecast costs over a lengthy plan period, and utilities are at risk that costs will exceed even their best cost forecast. In addition, forecast-based ARMs in the United States typically have predetermined "stair-step" trajectories that are insensitive to inflation outcomes. Table 6 summarizes the advantages and disadvantages of MRPs from the utility's perspective.

Table 6. Multi-Year Rate Plans From the Utility's Perspective

Advantages	Superior returns for superior performance Greater marketing flexibility Improved cost containment and marketing can become new earnings driver Better performance needed in period of mounting competition Better performers more likely to make successful mergers and acquisitions Utilities typically have expertise to support their MRP proposals Predictable revenue growth Streamlined regulation, a particular benefit for companies with multiple utilities
Disadvantages	Operating risk may increase materially Corresponding increase in target ROE unlikely Difficult to accommodate occasional cost surges Greater focus on a utility's comparative performance

5.2. Performance Incentive Mechanisms

Regulators have used targeted PIMs for many years to address traditional performance areas such as reliability, safety, power plant performance and energy efficiency programs. In recent years, these mechanisms have received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding DERs and other less-conventional technologies and practices.

However, PIMs pose risks for utilities as well as for regulators and customers, particularly when financial incentives are applied. This section considers the advantages and disadvantages associated with PIMs from these different perspectives.

5.2.1 Customers' Perspective

Overarching Issues Associated With PIMs

Advantages of PIMs From the Customers' Perspective

Utility performance metrics and incentives can serve as valuable regulatory tools for several reasons. First, PIMs can be targeted to performance areas of special concern to customers, including areas that might not otherwise receive sufficient utility attention. For example, PIMs allow regulators to encourage better utility performance in areas where historical performance has been unsatisfactory. PIMs can also help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.

Second, PIMs help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized or well understood.

Third, PIMs allow regulators to offset or mitigate current financial incentives that create a bias toward capital investments.

Fourth, where utilities are subject to economic and regulatory cost-cutting pressures, PIMs can encourage utilities to maintain, or even improve, customer service, customer satisfaction and other relevant performance areas.

Fifth, well-designed PIMs for DERs can encourage utilities to use DERs cost effectively. Such PIMs create incentives to use DERs to contain the cost of fuel and purchased power. Incentivized cost trackers for fuel and purchased power are difficult to design and rarely used. PIMs for DERs can also help MRPs strengthen incentives to slow rate base growth.

Finally, PIMs can be applied incrementally and gradually over time. Thus, they represent a relatively flexible, low-risk and low-cost regulatory option.

THE REGULATORS' PERSPECTIVE

Regulator interests frequently overlap with customer and utility interests. Here we highlight several advantages and disadvantages that may be especially pertinent to regulators.

Advantages of PIMs

- Can make regulatory goals explicit
- Can encourage better utility performance in areas of concern
- Can help to ensure cost-cutting does not lead to degradation of service or safety
- Relatively low-risk and low-cost option for improving key performance areas

Disadvantages of PIMs

- Design, implementation, and review may be complex, contentious and resource intensive
- May distract regulators and utilities from more important issues
- Design of PIMs may favor utilities, be subject to gaming and manipulation, or lead to unintended consequences
- Important performance areas may be missed because they are not easy to address with PIMs

Disadvantages of PIMs From the Customers' Perspective

PIMs require regulators and stakeholders to identify specific performance areas and quantify the desired outcomes. Regulators and stakeholders might not have the resources and wherewithal to explicitly identify all areas where performance should be improved or to define all desired outcomes.

PIMs can be targeted to performance areas of special concern to customers, including areas that might not otherwise receive sufficient utility attention. For example, PIMs allow regulators to encourage better utility performance in areas where historical performance has been unsatisfactory. PIMs can also help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.

Utilities can exploit information asymmetries and their funding advantages to lobby for terms that are overly favorable to their interests. Many PIMs involve awards for utilities but not penalties.

PIMs may not address some kinds of DER initiatives because load impacts and benefits are hard to measure.

In practice, PIMs tend to focus on areas where it is relatively easy to reach agreement, such as service quality, reliability and conventional energy efficiency programs. More sensitive issues that may matter greatly to customers, including general cost management, are harder to address with PIMs. For example, a PIM is less likely to be proposed and approved for reductions in actual substation cost than for DER-enabled reductions in load that might one day reduce such costs.

The design of PIMs can be quite complex. PIMs can require ongoing regulatory and stakeholder time and resources. It is difficult to establish the right amount of incentive.

Metrics and Targets

Advantages of Metrics and Targets From the Customers' Perspective

Simply establishing performance metrics and targets (without financial repercussions) can provide a low-risk, low-cost means of highlighting and monitoring specific performance areas of interest to customers. Utilities will have an incentive to perform well on the specified performance areas, knowing that regulators and stakeholders are monitoring those areas. In addition, metrics and targets provide information that allows regulators and stakeholders to determine whether financial incentives are warranted for the specified performance areas.

Disadvantages of Metrics and Targets From the Customers' Perspective

Regulatory and stakeholder resources and time may be required upfront to establish the appropriate metrics, targets and reporting requirements. Some resources and time will be required on an ongoing basis to review and respond to periodic reports. The impact of some kinds of DER initiatives on load may be difficult to measure. Furthermore, some metrics and targets might create a distraction from other regulatory issues that warrant more attention from regulators, stakeholders and utilities.

Financial Incentives

Advantages of Financial Incentives From the Customers' Perspective

Financial incentives provide much stronger encouragement than metrics and targets alone for utilities to perform well in the specified performance areas. Financial incentives for customer- and third-party-owned DERs can help offset the bias that utilities have toward capital expenditures.

Financial incentives can also be designed to directly benefit customers. For example, financial penalties can be designed to give money back to affected customers in order to compensate for underperformance in the specified performance area.

Disadvantages of Financial Incentives From the Customers' Perspective

Experience to date has shown that there are many potential pitfalls associated with PIMs.[62] These pitfalls occur mostly as a result of financial rewards and penalties. Potential pitfalls include:

- *Disproportionate rewards (or penalties).* PIMs can sometimes provide rewards (or penalties) that are too high relative to customer benefits or utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.[63]

- *Unintended consequences.* Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.

Financial incentives provide much stronger encouragement than metrics and targets alone for utilities to perform well in the specified performance areas.

- *Uncertainty.* Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention and are less likely to achieve policy goals. In addition, significant and frequent changes to performance incentive mechanisms create uncertainty for utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.

- *Gaming and manipulation.* Every PIM carries the risk that utilities will game the system or manipulate results.

In most cases, these pitfalls can be managed through sound design and implementation of performance metrics and incentives. They can also be mitigated by ongoing evaluation of and improvements to the incentive mechanisms.

62 Whited, Woolf and Napoleon (2015) "Utility Performance Incentive Mechanisms: A Handbook for Regulators."

63 For example, financial rewards or penalties that are tied to the avoided cost of energy will fluctuate significantly according to fuel price or wholesale market price swings, creating great risk of over- or under-compensation.

In addition, significant regulatory and stakeholder resources may be required upfront to establish the appropriate financial incentives. Additional resources are required on an ongoing basis to review and respond to the financial incentives earned by the utility. With significant dollars riding on the outcome, proceedings to design and approve PIMs can be contentious and resource-intensive.

Furthermore, PIMs sometimes provide utilities with financial rewards for performance outcomes that they have an obligation to achieve anyway, in the absence of PIMs. Such PIMs might over-compensate utilities for the performance, to the detriment of customers.[64]

Finally, the regulatory review process associated with financial incentives can be significantly more cumbersome and contentious than the process required for metrics and targets alone, due to the costs and risks to both the utility and customers. Table 7 summarizes the advantages and disadvantages of PIMs from the customers' perspective.

Table 7. Performance Incentive Mechanisms From the Customers' Perspective

Advantages	Can encourage better utility performance in areas of concern Can make regulatory goals and incentives explicit May help mitigate utility bias toward capital investments Can be designed to directly benefit customers Can help to ensure cost-cutting does not lead to degradation of service or safety PIMs for DERs can be designed to encourage cost-effective DERs Metrics serve as a low-risk and low-cost option for highlighting and monitoring key performance areas
Disadvantages	Design, implementation, and review may be complex, contentious and resource intensive May distract regulators, stakeholders, and utilities from more important issues Design of PIMs may favor utilities, be subject to gaming and manipulation, or lead to unintended consequences Incentives may be insufficient to achieve goals Important performance areas may not be addressed

5.2.2 Utility's Perspective

Overarching Issues Associated With PIMs

Advantages of PIMs From the Utility's Perspective

PIMs alert utility managers to special concerns of regulators and customers. They can thereby help to keep relationships with regulators and customers on an even keel. Good customer relations are especially useful in an era of increasing competition.

64 This point does not necessarily apply to PIMs that require utilities to achieve exemplary performance.

Utility distribution companies have no opportunity today to invest in power generation, and vertically integrated utilities have less opportunity than in the past. Neither kind of utility typically profits from power procurement. Under these conditions, PIMs for DERs provide a valuable opportunity to profit from reduced power supply costs.

Like MRPs, PIMs can provide utilities with new earnings opportunities at a time when traditional opportunities are diminishing.

Like MRPs, PIMs can provide utilities with new earnings opportunities at a time when traditional opportunities are diminishing. Utilities are more likely to be good performers in the targeted areas. Managers are especially likely to respond to PIMs when their income is tied to the outcome.

PIMs involve considerably less operating risk for utilities than MRPs. Some PIMs involve only rewards and no penalties. This treatment is especially common with PIMs for DSM.

<u>Disadvantages of PIMs From the Utility's Perspective</u>

The awards available from PIMs are often small because of low award rates and the typically narrow range of performance areas addressed. Some PIMs involve penalties as well as rewards, and many involve only penalties. Metrics chosen are sometimes difficult to control, and targets are sometimes unreasonable. For example, targets may be unduly ratcheted upwards as utility performance improves.

Metrics and Targets

<u>Advantages of Metrics and Targets From the Utility's Perspective</u>

Metrics and targets are necessary to measure utility performance and focus the attention of utility managers.

<u>Disadvantages of Metrics and Targets From the Utility's Perspective</u>

Some metrics and targets may require more utility resources and commitment than are warranted for the relevant performance area and serve as a distraction for utility management from core goals. Some metrics are not easy to control. Targets chosen for metrics can be unreasonable.

Some metrics and targets may require more utility resources and commitment than are warranted for the relevant performance area and serve as a distraction for utility management from core goals. Some metrics are not easy to control. Targets chosen for metrics can be unreasonable.

Financial Incentives

<u>Advantages of Financial Incentives From the Utility's Perspective</u>

Financial incentives further alert utility managers to key concerns of regulators and customers even if they are small. The impact is magnified when the compensation of managers is tied to realization of metrics. Rewards for good performance can be a welcome source of earnings at a time when earnings growth opportunities are diminishing.

Disadvantages of Financial Incentives From the Utility's Perspective

Financial incentives can involve undue risk when targets are unreasonable and utilities have limited control over metric outcomes. Penalties also create bad press for utilities. These problems can be mitigated by normalizing metrics, using deadbands, and by averaging results over several years before awards and penalties are determined.

Some PIMs asymmetrically involve penalties but no rewards. This is counter to the workings of competitive markets, where good performance typically results in higher revenue. A "premium" quality product, for example, is so called because it commands a price premium. Thus, good quality should be rewarded, although the reward should be commensurate with customer benefits. Reward and penalty rates can be designed so that that the utility is only rewarded for performance that is sufficiently valued by regulators and customers. Symmetrical incentives require that stakeholders apply a balanced approach to the value of performance, because proportionate revenue adjustments potentially apply to good and bad performance. Table 8 summarizes the advantages and disadvantages of PIMs for utilities.

Table 8. Performance Incentive Mechanisms From the Utility's Perspective

Advantages	Alert utility managers to areas of special concern to customers and regulators
	Provide new earnings opportunities for utilities
	Pose lower risk than MRPs
	Help to maintain good relationships
Disadvantages	Financial rewards may be small
	Some PIMs involve only penalties
	Some PIMs may address areas that are largely outside of utility control
	Targets may be unreasonably difficult to meet
	May be resource-intensive and distract from core goals

5.3. Multi-Year Rate Plans Versus Stand-Alone PIMs

PBR around the world has chiefly taken the form of multi-year rate plans that include one or more PIMs. PIMs, particularly those related to reliability and service quality, are frequently implemented as part of the package of measures included in an MRP in order to counterbalance the MRP's strong cost- containment incentives.

Compared to MRPs, PIMs are more targeted to specific areas, more flexible, more transparent, and allow for more regulatory and stakeholder guidance on the desired outcomes.

The United States was an early innovator in the MRP field, but in recent years has not relied on MRPs as much as other countries such as Australia, Great Britain and Canada. The recent resurgence of interest in PBR in the United States appears to place a priority on adding PIMs to existing regulatory systems rather than adopting MRPs. This resurgence seems due in part to the large number of PIMs in the RIIO approach to regulation and the sizable rewards and penalties that ride on these PIMs. However, the RIIO approach also relies heavily upon MRPs to promote efficient utility operations. Furthermore, the unusually heavy financial incentives are largely due to the fact that there is an MRP.

This section of the report considers whether a narrow focus on stand-alone PIMs is warranted, or whether a more comprehensive MRP approach to PBR is a better choice. The issue we address here, then, is not whether PIMs are a good idea, or even whether more are needed, but instead whether they should be adopted to the exclusion of other MRP provisions.

5.3.1 Customers' Perspective

Arguments for Stand-Alone PIMs From the Customers' Perspective

Adding PIMs to a more traditional regulatory system can sometimes make more sense than adopting MRPs. PIMs can be applied incrementally and gradually, with relatively low risk to customers. Compared to MRPs, PIMs are more targeted to specific areas, more flexible, more transparent, and allow for more regulatory and stakeholder guidance on the desired outcomes.

Implementation of MRPs can involve significant controversies, complexities, and risk associated with designing ARMs, cost trackers, efficiency carry-over mechanisms and other plan components. Due to asymmetries, where utilities frequently have more information and resources than regulators and stakeholders, designing MRPs in a way that both provides utilities with sufficient revenues and protects consumers can be challenging, resource intensive and contentious. PIMs offer a simpler way to provide regulatory guidance on targeted aspects of utility performance. While the design of PIMs is also subject to some controversy and complexities, the stakes are generally much lower than in MRP design, and the process may be less contentious.

Instead of focusing on the utility's entire revenue stream, PIMs typically provide relatively small financial rewards or penalties to utilities, resulting in less risk of providing inappropriate financial rewards. In addition, PIMs can be more incrementally and gradually modified with modest improvements based on lessons learned over time, again reducing risks to customers.

PIMs allow regulators and stakeholders to provide much more focused guidance on the areas of performance they wish utilities to attend to. PIMs can be used to specifically identify desired levels of performance regarding the development of different types of DERs, the provision of network support services, environmental performance and more. None of these areas of performance can be specifically guided with MRPs and, in the absence of PIMs, MRPs might provide financial incentives for utilities to ignore or underperform in some of these important areas.

Multi-year rate plans strengthen utility incentives to undertake a much wider range of actions to improve utility performance, including diverse cost containment strategies.

PIMs also provide much more transparency regarding targeted aspects of a utility's performance, relative to MRPs. The use of metrics, targets, reporting, and compliance practices allows regulators and stakeholders to observe exactly how well a utility is performing in the relevant performance area. The reporting can be conducted on a relatively frequent basis — for example, once a year — to provide ongoing information that can enable utilities and regulators to respond to underperformance in a timely way if necessary. MRPs, in the absence of appropriate PIMs, do not provide this type of focus or information on specific performance areas (e.g., customer engagement, network support services).

Unlike MRPs, PIMs do not necessarily require benchmarking or indexing a utility's performance relative to a peer group of other utilities, thereby avoiding all of the challenges of identifying and analyzing a truly comparable peer group.

Arguments for Multi-Year Rate Plans From the Customers' Perspective

PIMs typically address a fairly narrow range of concerns, such as reliability and DSM programs. Multi-year rate plans strengthen utility incentives to undertake a much wider range of actions to improve utility performance, including diverse cost containment strategies.

A popular argument for stand-alone PIMs is that they involve lower financial stakes for utilities and their customers. This may be true for performance areas where high stakes are not required to elicit good utility performance, or where modest dollars are ventured experimentally for new performance areas. However, stand-alone PIMs with sufficient incentive power to induce utilities to fully embrace DERs wherever they are an efficient alternative to utility capital expenditures would require sizable stakes.

MRPs are sometimes criticized for the controversies, complexities and risk associated with their design. However, MRPs can materially reduce the frequency of general rate cases and can therefore reduce needless regulatory cost, freeing limited consumer resources to participate more effectively in other proceedings. Moreover, there are analogous means to gradually transition to MRPs, such as starting with two- and three-year rate case moratoria. Learning from experience with MRPs around the world reduces the risk of a bad outcome.

Stand-alone PIMs, in contrast, do not offer the clear prospect of reduced regulatory cost. PIMs designed to encourage DERs to reduce load growth can be complex. In the absence of MRPs, these PIMs must do the "heavy lifting" to provide a positive incentive to contain rate base growth. The most common "shared savings" approach to the design of such PIMs requires, first, an estimate of the energy and capacity savings realized from DERs. An estimate is then needed of the monetary benefits of these savings — i.e., the avoided costs. This is fairly straightforward for tracked costs such as generation and purchased power expenses, but is much more difficult for costs that are fixed in the short run, like those for transmission, distribution and utility-owned generation capacity.

In contrast, under a well-designed MRP that includes revenue regulation, utilities have an incentive to use a wide range of DERs as well as other tactics to contain cost without linking revenue to complicated or narrowly focused avoided cost estimates. The utility can even enjoy cost savings from DER activities of independent DSM agencies or energy service companies and has a stronger incentive to encourage DER activities of third parties. Thus, an MRP may create stronger performance incentives at lower net regulatory cost.

The ability of PIMs to permit regulators to provide focused guidance on areas of special concern is not an absolute benefit.

The ability of PIMs to permit regulators to provide focused guidance on areas of special concern is not an absolute benefit. In designing PIMs, regulators tend to focus on areas of conspicuous controversy and do not always recognize important problems or the most effective means of solving problems.

MRPs need not discourage the monitoring of performance areas that interest regulators. To the contrary, performance metrics are an important part of MRPs, and some metrics (e.g., those for service quality) tend to garner increased attention under MRPs. It is a plus, not a minus, that the design of MRPs raises interest in issues like the productivity growth and operating efficiency that are implicit in a utility's cost forecast. These issues are of vital interest to consumers in any regulatory system, and raising them encourages better utility performance. Table 9 summarizes the arguments for stand-alone PIMs versus MRPs from the customers' perspective.

Table 9. Stand-Alone PIMs Versus MRPs From the Customers' Perspective

Arguments for Stand-Alone PIMs	Simpler means of providing regulatory guidance than MRPs Lower financial stakes tend to engender less controversy during design Limited financial implications reduce risk for customers Can be implemented gradually Provide highly targeted regulatory guidance on specific performance areas Metrics provide stakeholders with key information for monitoring performance PIMs need not address complicated issues like general cost management
Arguments for MRPs	Stronger cost containment incentives than PIMs May provide stronger, more cost-effective incentives for DERs Financial stakes not necessarily higher than with PIMs Streamlined regulation is especially valuable in jurisdictions with numerous utilities Can also be implemented gradually

5.3.2 Utility's Perspective

Arguments for Stand-Alone PIMs From the Utility's Perspective

Stand-alone PIMs can make more sense than MRPs for utilities in a number of circumstances. For example, PIMs may be preferable to MRPs where the current regulatory system yields adequate revenue (due to the use of cost trackers, forward test years or other mechanisms), or where regulators and stakeholders may be resistant to proposals for sweeping change to the traditional regulatory structure.

Stand-alone PIMs may also be preferred where it is difficult for the utility and stakeholders to agree on a compensatory mix of cost trackers and ARMs due, for example, to stakeholder and commission skepticism over a proposed accelerated modernization. Parties may insist that the utility do its own planning and submit to the usual prudence reviews at the time assets become used and useful.

Additionally, stand-alone PIMs may be preferred where there is limited need for marketing flexibility in a utility service area (for example, where there are few price-sensitive, large-load customers or where advanced metering infrastructure has not been installed), or where containing regulatory cost is not a key concern (e.g., where the utility company does not operate in multiple jurisdictions).

Arguments for MRPs From the Utility's Perspective

MRPs may make more sense for utilities operating under conditions other than those described above. Regulatory cost may be a special concern due to ownership of multiple utilities. Local regulation may be conducive to movement in this direction due, for example, to experience with forward test years and an adequately funded commission staff.

MRPs are also favored where it is relatively easy for the utility and stakeholders to agree on a set of ARMs and cost trackers due, for example, to a relatively predictable cost trajectory and regulator experience in reviewing costs that merit tracking. Marketing flexibility may be especially important due to price-sensitive loads, interest in EVs and green power, or new rate design and marketing opportunities created by advanced metering infrastructure. Table 10 summarizes the advantages and disadvantages of PIMs vs. MRPs from the utility's perspective.

Table 10. Stand-Alone PIMs Versus MRPs From the Utility's Perspective

Arguments for Stand-Alone PIMs	Can be implemented without significant regulatory change MRPs may be hard to negotiate More marketing flexibility may not be needed Some utilities enjoy adequate revenues under current regulatory system
Arguments for MRPs	Reduces cost of regulating multiple utilities Regulators and stakeholders are amenable to MRPs Costs are relatively predictable Facilitates marketing flexibility Can reduce regulatory cost

5.4. What Can the United States Learn From the British Approach to PBR?

Britain has one of the world's longest histories with the MRP approach to electric and gas utility regulation. Regulators there have devoted considerable thought to how best to refine MRP methods in each price control review. The new RIIO approach is the outcome of a particularly lengthy review and reflects years of trial and error.

RIIO has been mentioned in a number of recent papers as a promising new model for regulating the "utility of the future."

RIIO has been mentioned in a number of recent papers as a promising new model for regulating the "utility of the future."[65] Appraisal of RIIO in the United States is complicated by the different terms used in Great Britain for regulatory mechanisms (e.g., performance metrics are "outputs") and by the many differences in the regulatory approach used there. This section considers advantages and disadvantages of RIIO from the perspectives of U.S. utilities and customers.

In general, the RIIO approach offers many advancements in MRP design that may be worth considering in the United States.

[65] Alvarez, P. (2014); Binz and Mullen (2012); Fox-Penner, Harris, and Hesmondhalgh (2013); Lehr and Paulos (2013).

However, RIIO is a highly complex and expensive approach to MRP design, with considerable risk for both utilities and customers due in part to the eight-year term between rate cases. While certain aspects of RIIO are being discussed in the United States, to date no jurisdiction has expressed an intent to adopt the whole approach.

5.4.1 Customers' Perspective

Advantages of RIIO From the Customers' Perspective

The following RIIO innovations are especially promising and may offer improvements to current PBR practices in the United States:

- Conversion of multi-year cost forecasts into ARMs with inflation-adjusted revenue trajectories provides utilities with more inflation protection than the "stair-step" ARMs that are popular in U.S. MRPs. This reduces utility risk without weakening performance incentives and can permit an expansion of the plan period.
- Incentive-compatible menus have promise in the design of ARMs and other MRP provisions.
- Ofgem provides extensive funding for independent benchmarking and engineering studies as part of the process to review capital plans and establish appropriate revenue requirements.
- Low-controversy MRP applications are accorded "fast track" treatment, which helps to reduce regulatory cost and allow regulators and stakeholders to focus on more difficult applications.
- Ofgem has used PIMs to address new performance areas, such as the Information Quality Incentive (which seeks to reward utilities for providing accurate cost projections) and distributed generation connections.
- Utilities make payments directly to affected customers for poor service quality.
- Totex budgeting reduces the incentive to grow rate base.

RIIO is an unusually expensive and time-consuming approach to MRP design.

Disadvantages of RIIO From the Customers' Perspective

The RIIO approach also has several potential limitations and disadvantages that should be considered before adopting RIIO practices in the United States, including the following:

- RIIO is an unusually expensive and time-consuming approach to MRP design. This is due in large measure to the use of forecast-based ARMs and eight-year plan terms. Most first-generation RIIO plans for power distributors took 30 months to develop. The high regulatory cost is all the more remarkable in view of the fact that the approval process is not litigated. Ofgem employs approximately 800 staff members. U.S. regulators and stakeholders may lack the resources and experience to undertake such proceedings. It may be risky to trim steps in the review process, such as statistical benchmarking, in order to expedite the process to be more consistent with U.S. regulatory timeframes.

- Requiring eight years between rate cases significantly reduces the ability of regulators and stakeholders to review utility investments and increases the risk of unintended outcomes or extended detrimental effects on consumers.

- Incentive-compatible menus have been rejected three times in Canadian MRP proceedings.[66]

- Since British power distributors do not administer DSM programs, RIIO provides no guidance as to how to design PIMs that encourage utility DSM.

Requiring eight years between rate cases significantly reduces the ability of regulators and stakeholders to review utility investments and increases the risk of unintended outcomes or extended detrimental effects on consumers.

Other Approaches to PBR Are Also Advantageous

Many advances in PBR have been made in North America and other regions that are worthy alternatives to the RIIO approach. For example:

- More economical approaches to ARM design have been developed in North America. Most notably, U.S. economists invented index-based ARMs that take advantage of information on industry cost trends and simulate competitive market outcomes.[67] Index-based ARMs are now widely used to regulate utilities in Canada, New Zealand and other countries. These can adjust the revenue requirement automatically for customer growth as well as inflation. Other notable U.S. innovations in ARM design include the hybrid approach to ARM design, the "tracker/freeze" approach, and the California practice of repeating the capital expenditures budget established in the forward test year in the out years of an MRP.

- The sample of standardized data on utility operations available in Britain for statistical benchmarking is much smaller than in the United States. For this and other reasons, Ofgem's statistical methods are rudimentary compared to the best North American and Australian practices.

- North American and Australian regulators have been more energetic in the development of efficiency carry-over mechanisms, although further progress in this field is needed. This is a promising alternative to the eight-year plan periods in RIIO.

- Consumer advocates play a more significant role in North American utility regulation than in Britain.

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66 Menus were rejected in the Ontario Energy Board's IRM1 and IRM3 decisions (Ontario Energy Board [2000; 2008]) as well as the Alberta Utilities Commission's 2012 decision approving PBR for four of the five large energy distributors in the province (Alberta Utilities Commission [2012]). In the OEB's IRM1 proceeding, the use of a menu was rejected because it added unnecessary complexity. In IRM3, the menu approach was not generally supported by parties and was barely mentioned in the OEB's decision. The Alberta Utilities Commission rejected the use of a menu because it believed that the proposed menu was poorly calibrated for Alberta utilities and difficult to understand and implement.

67 It is also noteworthy that U.S. regulatory economists independently developed the concept of incentive compatible menus. See, for example, Crew and Kleindorfer (1992).

- North America makes extensive use of settlements in ratemaking, and this approach has ready application in MRP design and approval. Several MRPs approved in North America were outlined in settlements. RIIO encourages consultations, but the regulator ultimately chooses the design and the elements of the MRP. Table 11 summarizes advantages and disadvantages of RIIO from the customers' perspective.

Table 11. RIIO Approach From the Customers' Perspective

Advantages of RIIO	Inflation adjustments are superior to "stair-step" ARMs Menu approach encourages utility to reveal its achievable cost "Fast track" treatment reduces regulatory cost PIMs creatively address new performance areas Customers are directly compensated for unsatisfactory performance "Totex" approach reduces bias toward capital expenditures
Disadvantages of RIIO	RIIO is a complex and expensive approach to MRP design Eight-year term increases period between regulatory review of investments Utilities may be hesitant to adopt technologies that were not in revenue forecast Provides no guidance on incentives to invest in energy efficiency MRP design practices in North America and Australia have many advantages

5.4.2 Utility's Perspective

Advantages of RIIO From the Utility's Perspective

For utilities, a key advantage of RIIO relative to MRPs in the United States is the blending of an index-based and forecast-based ARM, as well as the thoughtful balancing of the two. Specifically, the ARM used in RIIO is based primarily on a multi-year cost forecast, but it also includes an inflation adjustment mechanism. This inflation adjustment mechanism provides superior protection to utilities from inflation risk relative to many of the ARMs used in the United States.

Disadvantages of RIIO From the Utility's Perspective

Most U.S. regulators lack experience with MRPs and may not be inclined to adopt a framework as comprehensive and novel as RIIO. At least 20 U.S. states still use historical test years. Many of RIIO's features — such as totex budgeting and eight-year revenue projections — would likely involve too much change for these jurisdictions.

In addition, many regulators lack the budgets for independent engineering and benchmarking studies. Some utilities would, in any event, be concerned about utility regulatory commissions undertaking these studies even if funding were available. Benchmarking is risky, and Ofgem's own cost forecast (not the utility's) is the primary basis for establishing the ARM.

Further, eight-year ARMs do not provide utilities with much flexibility for dealing with unforeseen challenges, even if the ARM is based on a utility's own forecast. Utilities will likely request supplemental revenue, which regulators may not grant. Thus, from a utility perspective, a RIIO-style MRP may not be desirable. Table 12 summarizes advantages and disadvantages of RIIO from a utility's perspective.

Table 12. RIIO Approach From the Utility's Perspective

Advantages of RIIO	ARM accounts for both utility forecast investments and inflation
Disadvantages of RIIO	Eight-year term unlikely to be embraced by regulators with little MRP experience Expenditure forecast set according to regulator's forecast of efficient expenditures Eight-year term increases risk of underestimating revenue needs

6. A Roadmap for Regulators

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies. In general, discussions of PBR options in a high DER future should evaluate and balance the range of potential MRP and PIM options that might fit any one state.

Table 13 presents a summary of how various PBR options might match different regulatory goals. The left column identifies the performance improvement goals a state might have; the middle column indicates the extent to which regulators and stakeholders are open to making regulatory changes; and the right column indicates the combination of PBR options that might be appropriate for that state.

Table 13. Regulatory Options to Fit Different Contexts and Meet Different Goals

Performance Improvement Goals	Openness to Regulatory Change	PBR Options
None	Low	Maintain current ratemaking practice
Improvement in specific areas	Low	Adopt PIMs for specific areas
General improvement in utility performance Streamlined regulation	Moderate to high	Adopt an MRP
Support for DERs	Low Moderate	Adopt PIMs for DER *or* revenue regulation Adopt PIMs for DERs *and* revenue regulation
Support for DERs General improvement in utility performance Streamlined regulation	High	Adopt PIMs for DERs, an MRP and revenue regulation

Regulators and stakeholders who are satisfied with current utility performance, and expect continued satisfactory performance in a high DER future, may prefer to maintain current regulatory practices.

Regulators and stakeholders who would like to promote improvements in utility performance should consider what areas of performance are most in need of improvement and are most critical in a high DER future. If their main concern is to improve performance in specific areas, stand-alone PIMs might be sufficient to address these areas. If they instead seek wide-ranging performance improvements, including better capital cost management, MRPs may be better suited to these goals than PIMs alone.

Regulators and stakeholders who wish to improve performance comprehensively and also focus on specific areas of performance in need of improvement should consider MRPs with an appropriately tailored package of PIMs. For example, an MRP with revenue decoupling, tracker treatment of DER-related costs, and PIMs related to cost-effective DERs can provide strong encouragement for utilities to support cost-effective DERs.

Whether any jurisdiction should take steps toward adopting MRPs or PIMs depends on how well existing regulation is working and the extent to which regulators and stakeholders wish to accept the risks and transition costs associated with new policies.

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Show Me the Numbers

A Framework for Balanced Distributed Solar Policies

Prepared for Consumers Union

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EXECUTIVE SUMMARY

Jurisdictions across the country are grappling with the challenges and opportunities associated with increasing adoption of distributed solar resources. While distributed solar can provide many benefits—such as increased customer choice, decreased emissions, and decreased utility system costs—in some circumstances it may result in increased bills for non-solar customers. In setting distributed solar policies, utility regulators and state policymakers should seek to strike a balance between ensuring that cost-effective clean energy resources continue to be developed, and avoiding unreasonable rate and bill impacts for non-solar customers.

To address this challenge, many jurisdictions are considering modifying distributed solar policies or implementing fundamental changes to rate design, such as increased fixed charges, residential demand charges, minimum bills, and time-varying rates. While it is prudent to periodically review and modify rate designs and other policies to ensure that they continue to serve the public interest, decision-makers frequently lack the full suite of information needed to evaluate distributed solar policies in a comprehensive manner. As this report demonstrates, it is critical to have accurate inputs, especially for "avoided costs" in order to identify whether a policy will increase or decrease rates for non-solar customers.

Regulators must strike a balance between ensuring that cost-effective resources continue to be developed, and avoiding unreasonable impacts on non-solar customers.

This report provides a framework for helping decision-makers analyze distributed solar policy options comprehensively and concretely. This framework is grounded in addressing the three key questions that regulators should ask regarding any potential distributed solar policy:

1. How will the policy affect the development of distributed solar?
2. How cost-effective are distributed solar resources?
3. To what extent does the policy mitigate or exacerbate any cost-shifting to non-solar customers?

Answering these questions will enable decision-makers to determine which policy options best balance the protection of customers with the promotion of cost-effective distributed solar resources. This report describes the analyses that can be used to answer these questions.

Analysis 1: Development of Distributed Solar

Customer payback periods provide a useful metric to indicate the extent to which different solar policies will affect the growth, or lack of growth, of distributed solar resources. Policies that lead to very short customer payback periods will likely produce rapid growth in these resources, while policies that lead to very long customer payback periods will likely result in little growth. Market penetration curves can be used to estimate eventual customer adoption levels from customer payback periods. Changing a customer's payback period will impact how economically attractive distributed solar is, and thereby affect how many customers ultimately adopt the technology.

Analysis 2: Cost-Effectiveness of Distributed Solar

Distributed solar can offer the electric utility system and society a host of benefits, ranging from avoided energy and capacity costs to reduced impacts on the environment and greater customer choice. At the same time, distributed solar may impose administration and integration costs on the utility system. Many recent studies have assessed whether the benefits of distributed solar outweigh the costs. These studies are most informative when they use clearly defined, consistent methodologies for assessing costs and benefits.

The most relevant cost-effectiveness tests for evaluating distributed solar are the Utility Cost Test, the Total Resource Cost Test, and the Societal Cost Test, which are based on the cost-effectiveness analyses long applied to energy efficiency resources.

- The Utility Cost Test indicates the extent to which distributed solar will reduce total electricity costs to all customers by affecting utility revenue requirements.
- The Societal Cost Test takes a broader look and indicates the extent to which distributed solar will help meet a state's energy policy goals such as environmental protection and job creation, as well as reducing customer electricity costs.
- The Total Resource Cost Test, in theory, indicates the extent to which distributed solar will reduce utility system costs net of the host customer's costs. This test should be used with caution, as it has some structural constraints that limit its usefulness.

Analysis 3: Cost-Shifting from Distributed Solar

Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts. Distributed solar can cause rates to increase or decrease due to changes in electricity sales levels, costs, or both. A comprehensive rate impact analysis is the best way to analyze the potential for cost-shifting from distributed solar.

When evaluating cost-shifting, it is important to analyze both long-term and short-term rate impacts to understand the full picture. Often, the benefits of distributed solar are not realized for several years, while a decrease in electricity sales occurs immediately, resulting in short-term rate increases followed by long-term rate decreases. Thus a short-term rate impact analysis will not fully capture the impacts of distributed solar.

Because distributed solar resources can create both upward and downward pressure on rates, the combined effect could result in in either a net increase or decrease in average long-term rates.

In their most simplified form, electricity rates are set by dividing the utility class's revenue requirement by its electricity sales. Thus rate impacts are primarily caused by two factors:

1. Changes in costs: Holding all else constant, if a utility's revenue requirement decreases, then rates will decrease. Conversely, if a utility's revenue requirement increases, rates will increase. Distributed solar can avoid many utility costs, which can reduce utility

revenue requirements. Distributed solar can also impose costs on the utility system (such as interconnection costs and distribution system upgrades).

2. Changes in electricity sales: If a utility must recover its revenues over fewer sales, rates will increase. This is commonly referred to as recovering “lost revenues,” and is an artifact of the decrease in sales, not any change in costs. Lost revenues should be accounted for in the rate impact analysis, but not in the cost-effectiveness analysis.

Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors.[1] In very general terms, if the credits provided to solar customers exceed the average long-term avoided costs, then average long-term rates will increase, and vice versa.

Summary of Analytical Framework for Assessing Distributed Solar Policies

The results of the three analyses described above can be pulled together into a single framework to evaluate different distributed solar resource policies in an open, data-driven regulatory process. The framework proposed here includes several steps that policymakers, regulators, or other stakeholders can take to assess the implications of different distributed solar policies. These steps are summarized in Table ES.1.

Table ES.1 Steps Required to Assess Distributed Solar Policies

Step 1	Articulate state policy goals regarding distributed solar resources.
Step 2	Articulate all the existing regulatory policies related to distributed solar resources.
Step 3	Identify all of the new distributed solar policies that warrant evaluation.
Step 4	Estimate the customer adoption rates under current solar policies, and new solar policies.
Step 5	Estimate the cost-effectiveness of distributed solar under current policies and new policies.
Step 6	Estimate the extent of cost-shifting under current solar policies, and new solar policies.
Step 7	Use the information provided in the previous steps to assess the various policy options.

To facilitate understanding and decision-making, it is useful to summarize the results of the three analyses in a single table. Table ES.2 provides an example of how the results could be summarized for reporting and decision-making purposes.

The primary recommendation from this report is that regulators should require utility-specific analyses of: (1) distributed solar development, (2) cost-effectiveness, and (3) cost-shifting impacts of relevant distributed solar policies. This will allow for a concrete, comprehensive, balanced, and robust discussion of the implications of the distributed solar policies.

[1] Whether rates actually increase or decrease is also dependent upon a host of other factors not related to distributed solar.

Table ES.2 Summary of Hypothetical Results

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback *Years*	5-Year Penetration *%*	Utility Net Benefits *$ Million*	Total Resource Net Benefits *$ Million*	Societal Net Benefits *$ Million*	Avg. Bill Impact *$/mo*	Long-Term Avg. Bill Impact *%*
Policy 1							
Policy 2							
Policy 3							

Using the results of the analyses presented above, policymakers, regulators, or other stakeholders can review the projected impacts of various policy options to determine what course of action is in the public interest. Appropriate consideration of all relevant impacts will help decision-makers to avoid implementing policies that have unintended consequences or that fail to achieve policy goals. The results of such analyses can also help to determine the point at which certain distributed solar policies should be reevaluated and modified over time.

Given that each jurisdiction has its own policy goals and unique context, the ultimate policy decision reached may be different in each jurisdiction, even when based on the same analytical results. Nonetheless, the framework articulated above will provide decision-makers with the ability to balance protection of customers with overarching policy objectives in a transparent, data-driven process.

1. Introduction and Background

Distributed solar[2] can pose a challenge for policymakers, regulators, and consumer advocates as it can reduce system costs over the long-run, but in some cases may also result in increased bills for non-solar customers. This report is intended to provide a guide for decision-makers and other stakeholders who seek to strike a balance between ensuring that cost-effective resources continue to be developed, while avoiding unreasonable rate and bill impacts on non-solar customers.

Nearly every state in the nation has adopted net metering as a compensation mechanism for distributed solar customers. However, jurisdictions across the country are beginning to reevaluate their distributed solar policies. For example, in the first quarter of 2016, 22 states considered or enacted changes to net metering policies (NCCETC 2016). While simple to administer (and simple to understand), concerns have been raised that net metering may lead to unacceptable rate impacts on non-solar customers.

It is prudent to periodically review and modify distributed solar policies to ensure that they continue to serve the public interest. To date, however, many jurisdictions have developed or modified their policies in a piecemeal fashion, rather than based on a quantitative analysis of the various impacts that distributed solar can have on the utility system and other customers. Without appropriate data-driven consideration of all relevant impacts based, decision-makers risk implementing policies that have unintended consequences or that fail to achieve policy goals.

Regulators should strike a balance between ensuring that cost-effective resources continue to be developed, while avoiding unreasonable impacts on non-solar customers.

This report provides a framework for helping decision-makers analyze distributed solar policy options more comprehensively by evaluating three critical indicators:

- The likely customer adoption of distributed solar
- The cost-effectiveness of distributed solar
- The magnitude of cost-shifting to non-solar customers

Once the results of these analyses are available, decision-makers can evaluate their policy options to determine what course of action will be in the best interest of customers as a whole by balancing the protection of customers with development of distributed solar resources.[3]

Appendix A provides sample discovery questions designed to assist stakeholders obtain the key pieces of information required for conducting the analyses recommended in this report. It is critical to have accurate inputs, especially for avoided costs, to accurately estimate the impacts of distributed solar policies. The answers to these questions will differ across jurisdictions, and thus the framework should be applied using the best available information that is relevant to each jurisdiction.

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[2] We use the term "distributed solar" to refer to small solar photovoltaic (PV) systems that are located on the distribution system. These systems generally take the form of rooftop PV operating behind the meter, but may also include installations not sited at the point of use, such as community solar.

[3] Regulators are tasked with implementing laws that have been adopted by the state legislature or executive branch. In some cases utility regulators have a wide range of policy options; in other cases the options are dictated by the state government.

2. Distributed Solar Policy Options

A comprehensive analysis of distributed solar policy options should begin with an explicit articulation of the jurisdiction's energy policy goals. Such policy goals may include (a) reducing electricity costs, (b) promoting customer control or choice, (c) reducing environmental impacts, and (d) promoting local jobs and economic development. In addition, jurisdictions generally attempt to balance these goals with the goal of avoiding or mitigating unreasonable cost-shifting to non-solar customers. These policy goals should inform the selection of policy options related to distributed solar and the evaluation of their impacts.

Policies that impact distributed solar include, but are not limited to: compensation mechanisms; rate designs that directly affect the credits that solar customers receive; program enrollment level caps; interconnection standards that govern the processes for connecting to the grid; and other policies designed to reform long-term grid planning efforts such that higher penetrations of distributed solar can be more easily accommodated and optimized on the grid. Regulators and policymakers can adjust these policies to encourage balanced growth of distributed solar and to mitigate rate impacts. The table below provides examples of the various types of policy options and supporting activities.[4]

Table 1. Distributed Solar Policy Categories

Policy	Examples
Compensation Mechanisms	Net metering, feed-in-tariff, value-of-solar tariff, renewable energy certificates, rooftop lease payments, performance incentives
Rate Design	Fixed charges, demand charges, time-of-use rates, bypassable versus non-bypassable bill components
Up-Front Incentives and Financing	Investment tax credits, sales tax exemptions, rebates, loans, grants
Interconnection and Permitting	Expedited review, mandated time limits, zoning exemptions, interconnection and permitting fees
Integration and Planning	Hosting capacity analyses, integrated resource planning, distribution system planning
Ownership	Customer up-front purchase, third-party ownership, utility ownership and lease to customer, loans
Education, Training, And Outreach	Information, tools, workshops, online assistance, community outreach

[4] Many residential and small commercial customers choose to lease their system or enter into a power purchase agreement (PPA) with third-party solar developers. Therefore it may be important to understand how various policies affect these developers, rather than only the host customers, when considering policy options.

In this report, we focus primarily on compensation mechanisms and rate design for residential and small commercial solar customers.[5] Often compensation mechanisms and rate design work in tandem, such as under net metering policies where a change in rate design can affect the net metering credit. Compensation mechanisms and rate design are particularly important policies for decision-makers to consider, as they can impact the rate of adoption of distributed solar, the magnitude of any rate impacts on non-solar customers, and the extent to which utilities are able to recover their allowed revenues.

In this report, we focus primarily on compensation mechanisms and rate design for residential and small commercial solar customers.

2.1. Rate Design and Distributed Solar

The Purpose of Rate Design

When considering rate design modifications, it is important to keep in mind the core objectives of electricity rates. In 1961, Professor James Bonbright set forth eight rate design principles, and distilled these principles into the following three objectives:

1. The revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies;
2. The fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and
3. The optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received (Bonbright 1961, 292).

The first objective seeks to ensure that utilities are able to recover sufficient revenues; the second objective is focused on fairness of rates; and the third objective addresses efficient resource usage.

These three objectives are still as relevant today as they were in 1961, with one modification. Customers are no longer only consumers; rather, they are increasingly also producers of a range of services, such as energy generation, demand reduction, and even ancillary services. For this reason, the third objective need not be limited to encouraging customers to *consume* electricity efficiently, but also to *produce* electricity (and related services) efficiently. With this modification, Bonbright's third objective also

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[5] For simplicity, we assume that rate design and compensation mechanisms will affect the payback period for both third-party developers and host customers who purchase their systems outright in a similar manner.

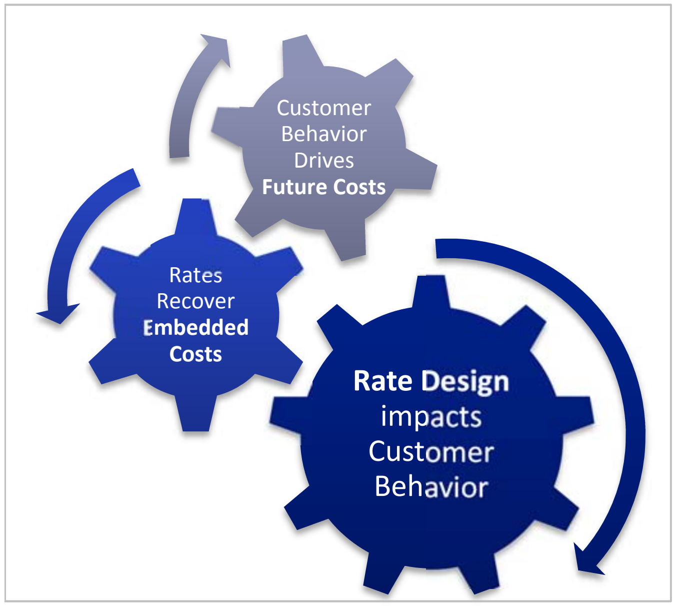
includes the primary objective of resource planning, namely the cost-effective procurement of resources, including distributed solar.[6]

Rate Design as a Balancing Act

Regulators strive to protect the long-run interest of customers by overseeing the provision of reliable, low-cost energy, while also ensuring that rates are fair, just, and reasonable. At its essence, ratemaking requires a balancing of multiple interests, as the principles and objectives enumerated by Bonbright are often in tension with one another.

The tension among ratemaking objectives stems not only from the need to balance the interests of different parties (utilities, customer classes, and individual customers), but also the need to recover *historical* (embedded) costs while sending price signals that drive efficient *future* investments by affecting customer behavior.

Figure 1. Relationship Among Historical Costs, Future Costs, and Rate Design



In order to meet both of these objectives, rate design should be informed by two different types of analyses: embedded cost of service studies and forward-looking resource plans.

Cost-of-service studies help to establish relationships between utility costs and customer consumption, and allocate historical costs equitably by dividing the revenue requirement among customer classes based on each class's contribution to past investments and operating expenses.

Once the revenue requirement for each class has been set, the focus shifts to minimizing *future* costs, rather than simply recovering historical costs. Rates are designed to recover a set amount of revenues, but also to provide customers with appropriate price signals to help customers make efficient consumption and investment decisions (including investments in distributed solar) that will help minimize long-term system costs.

The connection between the two primary analyses and rate design can be summarized as follows:

- **Cost-of-Service Studies:** The primary purpose of embedded cost-of-service studies is to identify how to allocate the revenue requirement across the rate classes. The revenue requirement is largely the product of *historical* investments made by the utility to serve

[6] This discussion assumes continuation of the current electric utility structure. However, the electric utility model is beginning to evolve to accommodate a more distributed, customer-centric future, and to better address policy goals such as reducing greenhouse gas emissions. As such, the primary objectives of rate design may need to evolve as well.

various customer classes. While cost-of-service study results can be used to inform rate design, the cost-of-service study should not be used to dictate rate design, as it does not account for future costs.

- **Resource Planning:** The purpose of resource planning is to identify those *future* resources and investments that are cost-effective and in the public interest. Cost-effective resources may include distributed energy resources as an alternative to supply-side resources or investments in traditional utility infrastructure. This exercise provides an indication of how much distributed solar should be implemented or encouraged by the utility to cost-effectively meet future resource needs and minimize long-term system costs.

Rate design plays an important role in the procurement of distributed solar. Unlike traditional supply-side resources, distributed resources are rarely procured directly by a utility. Instead, distributed resources are generally installed by individual households and business owners. Since rate design can significantly impact the economics of distributed solar systems installed by such utility customers, it serves as a primary tool for stimulating or stifling the installation of additional distributed solar on the utility system.

Figure 2 summarizes the connections among cost of service studies, rate design, and resource planning, as well as the different types of costs considered in each analysis.

Figure 2. The Role of Cost of Service Studies, Rate Design, and Resource Planning

Cost of Service Studies	Rate Design	Resource Planning
•Goal: Cost allocation •Costs: Based on historical (embedded) costs •Connection: Used as one input to rate design, but does not dictate rate design.	•Goal: Revenue recovery, equity, efficient price signals •Costs: Addresses both historical and future costs •Connection: Price signals influence distributed solar and energy usage decisions	•Goal: Low-cost, reliable, safe, electric service •Costs: Based on future costs •Connection: Influenced by customer distributed solar and energy usage decisions. Also may influence future customer investment decisions.

Rate Design Options

The underlying rate design has a direct impact on the financial viability of distributed solar, as it determines the degree to which customers can reduce their electricity bills by investing in distributed solar. For example, increasing the fixed charge reduces the variable rate, effectively also lowering the net metering compensation rate, and can thereby substantially reduce incentives for customers to install distributed generation (Whited, Woolf, and Daniel 2016).

Fixed charges are not the only form of rate design that can impact the adoption of distributed solar. Other rate designs include:

- **Demand charges:** A demand charge is typically based on a customer's highest demand during any one period (e.g., hour or 15-minute period) of the month. A demand charge often reduces the economic attractiveness of solar, since solar generation generally reduces demand much less than it reduces energy consumption.[7]

- **Minimum bills:** A minimum bill is similar in appearance to a fixed charge, but only applies if the customer's bill would otherwise be lower than the minimum threshold. While a minimum bill ensures that all customers contribute a certain amount to the system each month, it does not distort the variable rate.

- **Time-of-use rates:** Time-of-use rates are a simple form of time-varying rate that has been used for decades. A time-of-use rate assigns each hour of the day to either a peak, off-peak, or shoulder period. The energy rate is then set to be highest during the peak hours and lowest during off-peak hours to better reflect the actual underlying costs of providing electricity during those hours. A time-of-use rate can be designed in many ways. The particular design of the rate can either increase or reduce the economic attractiveness of distributed solar.

- **Inclining block rates:** These rates are set so that the first block of kilowatt-hours consumed each month (e.g., the first 200 kWh) is billed at a lower rate than the next block of consumption. Because net metering offsets a customer's highest block of consumption first, inclining block rates can increase the value of distributed solar to the host customer.

- **Declining block rates:** Declining block rates are the inverse of inclining block rates. Under a declining block rate, the electricity price declines as energy consumption increases. These rates are rare for small residential and commercial customers, but are more common for large commercial and industrial customers.

2.2. Compensation Mechanisms for Distributed Solar

Net Metering

Net metering allows customers to offset their electricity consumption with their system's generation on a one-to-one basis at the end of a month. Net metering is currently the most common method of compensating solar generation for the individual home or business, having been adopted in more than 43 states (NCCETC 2016). It has traditionally been applied to customers who install solar on their premises, but is increasingly also being applied to community solar options (discussed below).

There are many varieties of net metering, and the specific program design parameters can impact the economic viability of distributed solar. These parameters may include:

- **Program caps:** A cap closes the net metering program to new customers once a certain penetration level has been reached.[8]

[7] Solar customers frequently have high usage during non-daylight hours when solar panels are not producing energy. In addition, an hour of cloud cover during daylight hours can cause a solar customers' usage from the grid to spike temporarily.

[8] Caps can be expressed in different ways, such as a percent of historical peak demand, a percent of electricity sales, or in absolute megawatts of capacity.

- **System size limits:** Often net metering is limited to customers with relatively small systems, such as under 500 kW. In some cases, the size limit is based on the host customer's load.
- **Treatment of excess generation:** Programs vary in terms of how excess generation is compensated (i.e., when total generation exceeds consumption for the month), and whether bill credits can be rolled over to the next month.
- **Underlying rate design:** Residential customers are typically billed through a combination of fixed charges and variable rates (in cents/kWh), with net metering compensation provided at (or close to) the variable rate.[9] Changes to the variable rate can affect the ability of customers to offset their bills with net metering credits.

Buy All/Sell All

A buy all/sell all tariff requires that all energy consumed by the host customer be purchased from the utility at the retail rate, and all generation be sold to the utility at a different rate. This rate may be higher or lower than the retail rate. Two variants of the Buy All/Sell All approach are value-of-solar tariffs and feed-in tariffs, described in the following sections.[10]

Value-of-Solar Tariffs

Value-of-solar tariffs are an alternative to net metering that is based on the estimated net value provided by solar generation. This net value can be estimated in many different ways, but the key elements typically include:

- Avoided energy costs (e.g., fuel, O&M)
- Avoided capacity (generation, transmission, and distribution)
- Avoided line losses
- Avoided environmental compliance costs
- Costs imposed on the system (integration costs, administrative costs)

An example of a jurisdiction that uses a value-of-solar tariff is Austin Energy. The value-of-solar rate is set on an annual basis through Austin Energy's budget process (City of Austin 2016). Because it is set

[9] This compensation rate does not include certain non-bypassable riders or fees.

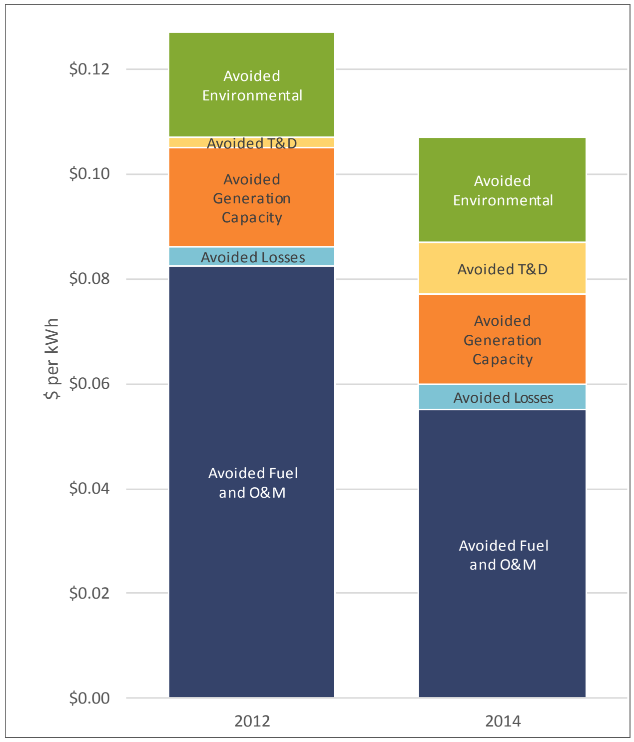
[10] Some concern has been raised that a Buy All/Sell All mechanism may create tax liabilities for solar owners. Under a Buy All/Sell All mechanism, the owner may be viewed as engaging in the sale of electricity, the proceeds of which could constitute gross income.

annually, the rate fluctuates from year to year but is generally in the range of 10 to 12 cents per kilowatt-hour.

The methodology used by Austin Energy to calculate the value-of-solar rate was originally set in 2012 and considers loss savings, energy savings, generation capacity savings, fuel price hedge value, transmission and distribution capacity savings, and environmental benefits (Karl Rábago et al. 2016).

Value-of-solar tariffs may be applied in different ways. One method is to require that all energy consumed be purchased from the utility at the retail rate, while all generation is sold to the utility at the value-of-solar rate (i.e., a buy-all/sell-all arrangement). Under this option, no netting is permitted. Other jurisdictions may apply the value-of-solar rate only to excess generation, while any generation consumed behind the meter is effectively netted at the retail rate.

Figure 3. Austin Energy's Value-of-Solar Tariff 2012 and 2014



Feed-In Tariffs

A feed-in tariff (FIT) operates similarly to a value-of-solar tariff, in that it compensates solar generation at an administratively set value. However, the goal of a FIT differs from a value-of-solar tariff in that a FIT is designed explicitly to provide an incentive to install distributed generation. Typically FITs are used to stimulate early adoption of new technologies that would otherwise be cost-prohibitive for most customers. As such, the FIT is generally designed to allow distributed generation customers to earn a reasonable return on their investment.[11]

Instantaneous Netting

Net metering has traditionally netted energy consumption against generation at the end of a billing cycle (e.g., on a monthly basis). However, recently some jurisdictions (such as Hawaii) have begun to experiment with what can be called "instantaneous netting." Under this approach, any generation consumed on-site offsets grid-supplied energy at the retail rate on a near-instantaneous basis, while any generation exported to the grid is credited at a lower rate (Public Utilities Commission of Hawaii 2015).

[11] FITs have been widely used in Europe (particularly Germany), and on a more limited basis in the United States. For example, Portland General Electric (PGE) solar customers can choose a feed-in-tariff option called the Solar Payment Option, which currently compensates customers at a rate much higher than the net metering rate for a period of 15 years. *See:* PGE, "Solar Payment Option - Install Solar, Wind & More," https://www.portlandgeneral.com/residential/power-choices/renewable-power/install-solar-wind-more/solar-payment-option.

This rate structure encourages customers to use as much of their generation as possible (or store it in batteries), rather than pushing it onto the grid.

2.3. Additional Options

Community Solar and Other Virtual Net Metering

Community solar allows customers who are unable to install solar PV on their homes or businesses to benefit from the solar energy produced by an off-site solar installation (also called “virtual net metering”).[12] Customers typically purchase a subscription or “share” of the electricity generated by the installation. Subscribers then receive both a charge for the subscription and a credit for the reduction in grid-supplied energy that are applied to their electricity bill. This credit may be equal to, more than, or less than the retail rate. Community solar installations have the advantage of removing some barriers to entry for installing solar systems. For example, community solar expands access to renters or other customers without suitable roof space, and to customers who have limited access to financing.

While community solar installations are typically much larger than the average residential system, smaller forms of virtual net metering are possible. In Massachusetts, a hybrid between large community solar arrangements and traditional net metering exists whereby an individual host customer can share his or her net metering credits with other customers who take service from the same utility (Public Utilities Commission of Hawaii 2015).

Renewable Energy Certificates and Solar Renewable Energy Certificates

Renewable Energy Certificates (RECs) and Solar Renewable Energy Certificates (SRECs) offer customers a financial incentive to install distributed solar by allowing customer generators to sell their RECs or SRECs to electricity suppliers, who are required by law to purchase a minimum number each year to comply with the jurisdiction’s Renewable Portfolio Standard (RPS) or its RPS solar carve-out.

Currently 29 states and the District of Columbia have RPS policies, while a smaller number of states have solar carve-outs. States with solar carve-outs and an SREC market include Massachusetts, New Jersey, New Hampshire, Pennsylvania, Ohio, Delaware, Maryland, and the District of Columbia (Barbose 2016). However, many other states in the eastern United States are able to participate in the SREC markets of states with solar carve-outs (SREC Trade 2016). Some states have adopted an approach that does not use separate SRECs, but provides solar customers with a multiplier on their RECs (Barbose 2016). For example, a state might provide 3 kWh worth of RECs for 1 kWh generated by distributed solar.

Basic market forces determine the value of a REC or SREC: the supply of credits is determined by the quantity of eligible resources currently in place, while demand is determined by the jurisdiction’s requirements. SREC prices are generally higher than RECs, and therefore tend to provide a stronger

[12] We note that the terms “community solar” and “virtual net metering” are used quite inconsistently across the country and also go by different names. For example, community solar may also be called “shared solar,” “community distributed generation,” or “neighborhood net metering.”

financial incentive for customers to install solar technologies. However, both SREC and REC markets can be volatile, thereby increasing the financial risk for solar customers.

Loans, Rebates, and Tax Credits

Jurisdictions may provide a variety of incentives that reduce the up-front costs of installing solar technologies, including subsidized loans, up-front rebates, and tax credits. For example, the federal government currently offers a 30 percent investment tax credit for residential customers who install solar.[13] In addition, many jurisdictions offer installation rebates, such as Austin Energy's rebate of $0.70/watt (equivalent to approximately 18 percent of the current median cost per watt).[14]

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[13] For more information, see the U.S. Department of Energy webpage at http://energy.gov/savings/residential-renewable-energy-tax-credit.

[14] For more information, see Austin Energy's website at http://austinenergy.com/wps/portal/ae/green-power/solar-solutions/solar-pv-systems/current-solar-incentive-levels.

3. Development of Distributed Solar

A comprehensive analysis of distributed solar policy options should begin with an explicit articulation of state energy objectives and how they relate to distributed solar. The table below provides examples of such objectives and their relationship to distributed solar.

Table 2. Policy Objectives and Distributed Solar

Objective	Relationship to Distributed Solar Policy Choice
Reducing Electricity Costs and Risk	To the extent that distributed solar reduces system electricity costs and diversifies energy sources, decision-makers may seek to promote distributed solar. For example, distributed solar may be part of a strategy to relieve grid congestion and reduce the need for significant and expensive upgrades of the distribution system.
Environmental Goals	Regulators may wish to encourage development of distributed solar to reduce carbon emissions or achieve other state environmental goals.
Promoting Customer Control or Choice	A state may wish to support the ability of all customer classes to self-generate as an alternative to purchasing electricity from the utility and to reduce their energy bills. Distributed solar can help to achieve these objectives.
Employment	States may promote distributed solar as a means to increase the number of jobs, particularly those in the clean energy sector.
Protect Non-Solar Customers from Unreasonable Rate Impacts	Distributed solar may increase rates and bills for non-solar customers. The impact on low-income customers may be of particular concern. To address this, states may wish to limit the total penetration of distributed solar, or develop alternatives, such as community solar and low-income solar programs, that allow the benefits to be spread across a greater number of customers.

A policy decision such as a change in rate design will impact the economics of investing in distributed solar, and thus customers' willingness to adopt the technology. Changes in the adoption of distributed solar will in turn affect how much distributed solar is ultimately developed in the jurisdiction, which may have two key impacts on utility customers:

1. If distributed solar results in cost-shifting to non-solar customers, higher solar penetration levels will likely exacerbate this effect.

2. If distributed solar helps to reduce electricity rates and meet a state's solar energy objectives, higher penetration levels will benefit customers over the long term.

For these reasons, decision-makers should consider current penetration levels, as well as how a policy change will affect future customer adoption rates. Jurisdictions that are currently experiencing low adoption rates may want to consider how solar penetration may change under different policies, particularly if technology costs continue to fall (discussed more below).

Customer adoption rates are influenced by many factors, ranging from the ease of the interconnection process to the availability of loans or the ability to lease a solar system from a third-party installer. In this report, however, we focus solely on the compensation mechanisms and rate designs that influence customers' willingness to install distributed solar.[15] For simplicity, we assume that the customer is purchasing a system up-front, as not all states currently allow third-party leases or power purchase agreements.

To estimate the impact of a policy on a customer's willingness to purchase and install a solar system, it is first necessary to calculate the payback period for a typical solar customer under the current policy and the new policy.

Estimating the Payback Period

The steps to estimate the simple payback period for a single-owner solar installation are as follows:

1. **Reference Bill:** Calculate the customer's average monthly bill under the current rate structure and incentives without distributed solar, to provide a point of reference.[16] This will require knowing, at a minimum, the average annual consumption level (in kilowatt-hours) for a typical customer. For more sophisticated rate structures (such as time-of-use rates or demand charges), it may be necessary to know a range of customers' load profiles in order to accurately estimate the reference monthly bill(s). Estimates of future grid-supplied electricity prices will also be helpful.

2. **Upfront System Costs:** Estimate the cost of installing a solar array, using the most up-to-date prices and incentive levels possible. Online tools and datasets such as the Lawrence Berkeley National Lab's "Tracking the Sun" reports,[17] and the National Renewable Energy Laboratory's (NREL) Open PV Project[18] can help to inform this estimate.[19] Include any up-front incentives that a customer would receive, such as the federal tax credit, which allows residential taxpayers to deduct a percent of the cost of installing a solar energy system from their federal taxes.[20]

[15] In other words, the discussion that follows assumes that the interconnection process, permitting process, and other factors do not present unreasonable barriers to customers. If this is not the case, then estimates of customer adoption should be adjusted accordingly.

[16] If electricity rates are projected to increase faster than inflation, an escalation rate should be applied to the reference bill for each year of the analysis.

[17] Lawrence Berkeley National Lab's reports catalogue the trends in the installed price of residential and non-residential solar systems installed in the United States. These reports can be found at trackingthesun.lbl.gov.

[18] The National Renewable Energy Laboratory maintains a database of installed costs of distributed solar by year at https://openpv.nrel.gov/search.

[19] In 2015, the median installed price was $4.10 per watt for residential systems, $3.50 per watt for non-residential systems less than or equal to 500 kW in size, and $2.50 per watt for non-residential systems larger than 500 kW (Barbose and Darghouth 2016, 20).

[20] This tax credit will remain at 30 percent through 2019, but is then scheduled to be reduced to 26 percent in 2020 and 2021, and 22 percent in 2022 (U.S. Department of Energy 2016).

3. **Ongoing System Costs:** Estimate the annual costs to maintain the system. NREL provides current estimates of operations and maintenance costs on its website.[21]

4. **Generation:** Quantify the anticipated solar generation (in kWh) for a typical solar array using a tool such as the NREL's PV Watts calculator.[22]

5. **Bill Savings:** Using the solar generation profile estimated in Step 4, calculate the annual electricity bill for a customer with distributed solar, and then compare this to the annual electricity bill for a similar customer without distributed solar (as calculated in Step 1) in order to quantify the annual bill savings.

6. **Other Benefits:** Estimate any additional annual financial incentives that a customer would receive for the electricity produced by their system such as production incentives or the projected value of renewable energy credits (if applicable). Do not include the value of up-front incentives that reduce the initial cost of the solar system, as these were included in Step 2.

7. **Simple Payback Period:** If the benefits and costs are assumed to not vary from year-to-year, the system costs can simply be divided by the annual benefits to derive the simple payback period. Otherwise, incrementally subtract the annual benefits (the sum of bill savings calculated in Step 5 and other incentives calculated in Step 6) from the system costs (the sum of Step 2 and Step 3) to determine how many years will be required for a customer to recoup his or her investment.[23]

Once the simple payback period under the current rate structure and incentive levels is calculated, repeat the process for any new policies under consideration.

It should be noted that there are many factors that can influence the payback period and can change quickly. For example, the installed cost of solar has fallen dramatically in recent years, as shown in the figure below, based on data from Lawrence Berkeley National Laboratory (Barbose and Darghouth 2016). The price of electricity also may change significantly from year to year, particularly for jurisdictions where energy prices are driven by volatile oil or natural gas markets. For this reason, payback periods (and the penetration levels that rely on payback period estimates), should be updated periodically.

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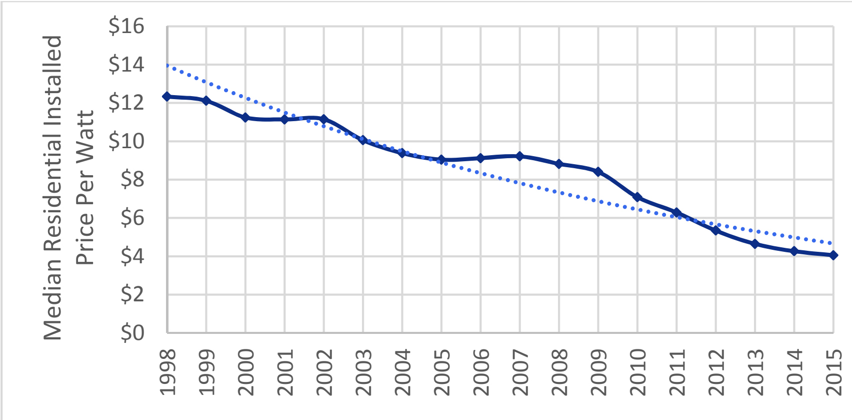
[21] In 2016, the estimated annual O&M costs for small residential systems was $21 (NREL 2016).

[22] The National Renewable Energy Laboratory's PV Watts calculator estimates the energy production from distributed solar systems throughout the world. The calculator also contains some cost information. http://pvwatts.nrel.gov/.

[23] The simple payback period calculation does not involve discounting.

Figure 4. Median Residential Installed Price of Solar



Source: Barbose and Darghouth, Tracking the Sun IX, August 2016.

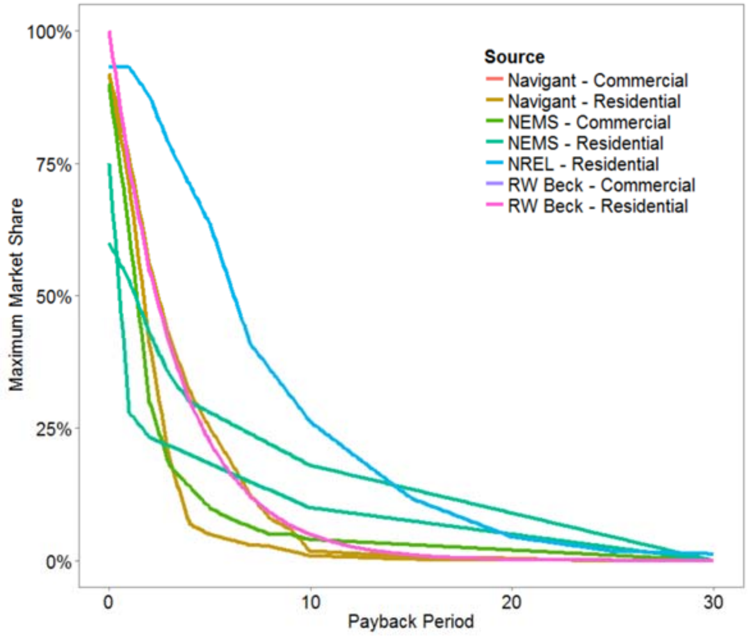
Customer Adoption Levels

The next step is to estimate the customer adoption levels for a certain payback period based on market penetration curves and estimates of the eligible population. Market penetration curves estimate the percentage of customers who will ultimately adopt a technology as a percentage of the total customers who would and could potentially install the technology.

Many customers cannot adopt solar because they have unsuitable roofs or do not own their residences. Other customers may have no interest in installing solar panels, even if they were provided for free. For example, out of 1,000,000 residential customers, perhaps only 650,000 customers own their residence and have roofs with little shading and an orientation suitable for solar. Thus the population of eligible customers should be determined for each jurisdiction based on surveys, home ownership rates, and analyses of rooftop suitability. If jurisdiction-specific estimates are not available, one can develop rough estimates from existing resources. One useful source is NREL, which developed estimates of the percentage of small buildings suitable for rooftop solar in each ZIP code using data on roof shading, tilt, and azimuth (Gagnon et al. 2016).

Once the population of eligible customers has been established, market penetration curves can be applied to estimate the proportion of the eligible population that would adopt solar based on a certain payback period. Ideally these curves will be developed for a particular jurisdiction using surveys. If this is not possible, curves developed for other jurisdictions can be used. For example, the graph below shows maximum market penetration curves for the residential and commercial classes as estimated by Navigant Consulting (Paidipati et al. 2008), the Energy Information Administration's National Energy Modeling System (NEMS) (EIA 2004), NREL (Sigrin and Drury 2014), and R.W. Beck (2009).

Figure 5. Market Penetration Curves from the Literature

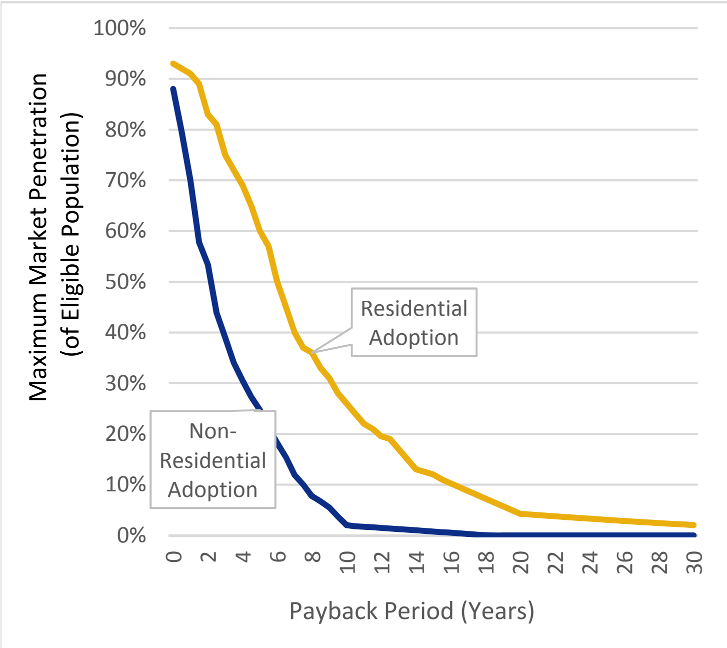


Source: Sigrin et al. 2016.

As demonstrated by Figure 5, estimates of market penetration can vary significantly based on what underlying data are used to estimate the curves and when the estimate was made. Such penetration curves may need to be adjusted over time as market factors change or as better data on customer adoption rates becomes available. These market penetration curves assume that there are no other substantial barriers to solar adoption (such as interconnection barriers, program caps, etc.). Moreover, it is unclear what effect alternative solar financing models (such as third-party leases) have on these curves. For this reason, we recommend that each jurisdiction conduct its own survey of customer willingness to adopt solar under different arrangements (including both customer ownership and third-party leases).

The market penetration curves recently adopted by NREL for its dSolar model (Sigrin et al. 2016) are approximated in the figure below. Using NREL's market penetration curves in Figure 6, a 15-year payback would be expected to result in 12 percent of possible residential customers being willing to purchase and install distributed solar, and 1 percent of possible commercial and industrial customers being willing to purchase and install distributed solar. It should be noted that the willingness of customers to adopt solar based on simple payback periods may not lead to actual project implementation if other types of barriers exist. For example, Navigant estimates that adoption levels may be reduced by as much as 60 percent if widespread interconnection challenges exist that create significant cost increases or result in project delays or cancellation (Paidipati et al. 2008, 10). On the other hand, if attractive financing options are available, actual penetration rates may be higher than those estimated based on payback periods.

Figure 6. Maximum Market Penetration Curves adopted by NREL



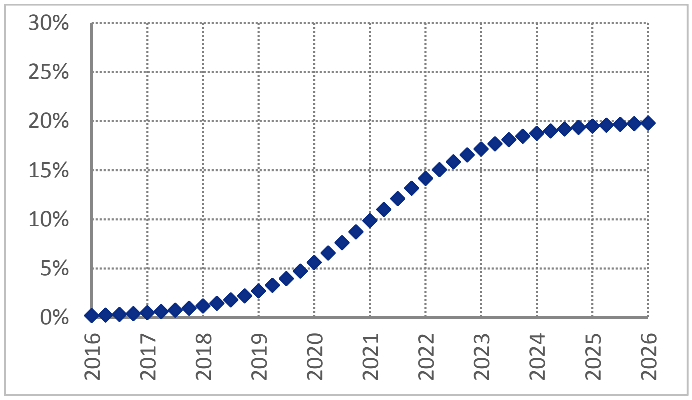
Source: Approximated from NREL's dSolar model as presented by Gagnon and Sigrin 2016.

Assuming that significant other barriers to installing distributed solar are not a factor, the penetration levels indicated by market penetration curves can be expressed as penetration levels for each rate class. They can also be converted to penetration as a percent of system peak demand or of energy sales. These expected penetration levels should be estimated for each policy option under consideration, as they are used to determine the net benefits provided by each policy option (described in the next section).

However, it is important to remember that the payback period is likely to change from year-to-year, and therefore the ultimate penetration of distributed solar estimated this year may be markedly different than an estimate made five years from now. To address this, policymakers may instead want to estimate the near-term penetration level (e.g., five years in the future), and revisit the estimate every few years.

To determine the likely penetration level in five years, rather than the ultimate penetration level, an expected adoption trajectory is required. New technology adoption often follows an "S-curve," which can be specified using the Bass Diffusion Model (Bass 1969). Under this model, growth begins slowly, enters into a rapid growth phase, and then begins to slow as it nears market saturation (i.e., the maximum percentage of the population that might ultimately adopt the product). A hypothetical S-curve for distributed solar is shown in Figure 7, below, based on the assumption that the market will saturate at 20 percent over a 10-year period.[24]

Figure 7. Hypothetical S-Curve of Distributed Solar Adoption



Note: Assumes that market saturation at 20 percent occurs in 10 years.

However, such adoption trajectories should be viewed as a snapshot in time, based on current payback periods. As factors influencing the payback period change (such as the price of solar panels), the market saturation level will also change. This key factor is not captured by the original Bass Diffusion Model, and thus the model must be re-estimated as financial parameters change, or an alternative model should be used (Chandrasekaran and Tellis 2007).

[24] The shape that the S-curve takes will vary based on parameters referred to as the "coefficient of innovation" and the "coefficient of imitation." Further research is required to accurately specify these parameters.

4. Distributed Solar Cost-Effectiveness

The basic premise of cost-benefit analysis is simple: All of the relevant costs of a resource are forecasted over a long-term planning horizon, along with all of the relevant benefits (otherwise referred to as the avoided costs). If the cumulative present value of the benefits outweighs the cumulative present value of the costs, the resource is considered cost-effective.[25] However, the magnitudes of the benefits and costs can vary considerably depending upon which costs and benefits are relevant. Several different cost-effectiveness methodologies are used to determine which costs and benefits are included in the analysis, as discussed in the section on cost-effectiveness tests below.

4.1. Costs and Benefits

Distributed solar can offer the utility system and society a host of benefits, ranging from avoided energy and capacity costs, to reduced environmental impacts. At the same time, distributed solar may impose administration and integration costs on the system. Table 3 lists many of the most frequently quantified benefits and costs.

Table 3. Potential Distributed Solar Costs and Benefits

Benefits
Avoided Energy Costs
Avoided Generation Capacity Costs
Avoided Losses
Avoided Transmission & Distribution Costs
Avoided Environmental Compliance Costs
Avoided Ancillary Services
Reduced Risk
Environmental Benefits
Costs
Administration costs
Interconnection Costs
Distribution System Upgrades
Participant Costs

It is important to note that the costs and benefits may vary greatly over time, due to changes in penetration levels and changes in avoided costs (such as changes in the price of natural gas). For example, distributed solar penetration of less than 5 percent may impose only very small administrative and integration costs on the system. However, penetration levels of 20 percent or more may impose significant costs on the system, stemming from the need to upgrade distribution system equipment to handle large amounts of solar generation. Another cost could be the need to install distributed generator visibility and control devices. For this reason, it is recommended that avoided costs be re-

[25] Where costs and benefits are difficult to quantify, reasonable approximations should be used until more detailed information is available (Woolf et al. 2014).

evaluated periodically, particularly if penetration levels are growing quickly, or if fuel prices are changing rapidly.

4.2. Cost-Effectiveness Tests

Distributed solar studies generally use cost-effectiveness methodologies that are based on, or at least consistent with, the methodologies that are commonly used for assessing energy efficiency cost-effectiveness. Five cost-effectiveness tests have long been used to analyze energy efficiency's costs and benefits from various perspectives. These tests are based on the California Standard Practice Manual (California Public Utilities Commission 2001).

In recent years, however, these tests have been subject to much debate. Many jurisdictions, including California, have been wrestling with questions regarding which of these tests should be used for evaluating energy efficiency and how. In response to this challenge, the National Efficiency Screening Project was formed several years ago to help improve the way that jurisdictions analyze the cost-effectiveness of energy efficiency resources (NESP 2014). NESP is currently in the process of preparing a National Standard Practice Manual to provide guidance on energy efficiency cost-effectiveness practices (National Efficiency Screening Project Forthcoming).

The main point from this debate on energy efficiency cost-effectiveness, for the purpose of this study, is that it is essential to understand precisely what information each test can provide, and what that information indicates regarding the cost-effectiveness of distributed solar resources. Each of the tests has advantages and limitations that must be considered when applying them. The following subsections describe the information that each of the tests can provide; and Section 4.3 describes what that information means for understanding the cost-effectiveness of distributed solar resources.

It is essential to understand precisely what information each test can provide, and what that information indicates regarding the cost-effectiveness of distributed solar resources.

The Utility Cost Test[26]

The purpose of the Utility Cost Test is to indicate whether a resource's benefits will exceed its costs from the perspective of the utility system. It does not, as the name implies, represent the perspective of the utility in terms of utility management or utility investors. It instead represents the perspective of the utility system. In other words, the Utility Cost Test represents the perspective of utility customers as a whole.

The Utility Cost Test should include all utility system costs that impact revenue requirements when additional distributed solar is added to the system. The utility system costs are comprised of all costs that the utility must recover from customers, such as net metering administration costs, interconnection costs beyond what is borne by the customer, and distribution system upgrades.

[26] This test is also referred to as the "Program Administrator Cost Test."

It is important to note that certain utility system costs—such as the cost of complying with an RPS or solar carve-out—are not incremental costs imposed by additional distributed solar, and should therefore not be included. The costs associated with such compliance (e.g., SRECs) occur as the result of the state's decision to create an RPS solar carve-out. These costs would be incurred by the utility regardless of whether additional distributed solar is implemented (assuming that the utility would have to procure the solar from the market or pay an alternative compliance fee). As such, SRECs do not get counted as a cost or benefit under the Utility Cost Test.[27]

One key limitation of the Utility Cost Test is that it does not reflect the extent to which distributed solar resources will achieve energy policy goals (beyond the goal of reducing cost).

The Utility Cost Test should also include all utility system costs that are avoided by the distributed solar resource, including avoided energy costs, avoided generation capacity, market price suppression effects, avoided transmission and distribution costs, avoided line losses, and avoided environmental compliance costs.

The key advantage of the Utility Cost Test is its simplicity; it indicates how distributed solar resources will affect electric utility costs to all customers as a whole. It is the methodology that utilities have used for years to assess the costs and benefits of electricity resource investments, and is the primary criterion for assessing costs and benefits in the context of integrated resource planning.

One key limitation of the Utility Cost Test is that it does not reflect the extent to which distributed solar resources will achieve energy policy goals (except for the goal of reducing costs). Most jurisdictions establish distributed solar policies for the explicit purpose of increasing fuel diversity and independence, reducing environmental impacts, and increasing local jobs and economic development. The Utility Cost Test, by design, does not reflect these types of benefits.

The Total Resource Cost Test

The purpose of the Total Resource Cost (TRC) Test is to indicate whether the benefits of distributed solar resources will exceed their costs from the perspective of the utility system and the host solar customer. This test, in theory, includes all costs and benefits of the Utility Cost Test, plus all costs and benefits to solar customers. Customer costs include all equipment, installation, and maintenance costs for the distributed solar facility, or solar lease payments (if applicable). The benefits include any benefits experienced by the solar customer (beside the benefits of reduced bills).[28] In theory, these non-bill customer benefits could reflect customer benefits such as reduced environmental impacts. In practice,

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[27] The question of whether or not a jurisdiction's RPS policy or solar carve-out is cost-effective and whether it should be pursued should be studied separately. For the purposes of this report, such policies are taken as a given and must be complied with in some manner.

[28] By design, the TRC Test includes the benefits (i.e., avoided costs) of the utility system. Customer bill reductions should not be included as a benefit in this test, because that would double-count some of these avoided costs. The Participant Cost Test is used to more specifically account for solar customer bill savings.

these non-bill benefits to solar customers are rarely properly estimated and included in solar cost-effectiveness analyses.[29]

The main advantage of the TRC Test is that it provides more comprehensive information than the Utility Cost Test, by including the impacts on participating customers. In this way the "total cost" of the resource is reflected in the test, regardless of who pays for those costs.

However, the TRC Test might not accurately capture the benefits to solar customers. The primary benefits to the host solar customer are in the form of customer bill savings, but the TRC Test does not include customer bill savings; instead the test includes avoided utility system costs. In those jurisdictions where retail rates (which determine customer bill savings) are different from utility avoided costs, this test will not accurately capture the impact on solar customers.

Further, in practice the TRC Test does not account for the non-bill benefits to solar customers. Since many solar customers install solar facilities for the purpose of reducing their environmental impact, this could lead to a significant understatement of the benefits in the TRC Test.

Because of these two limitations, the TRC Test might not represent the impacts on the utility system and the solar customers, as it purports to do. Instead, it would be more accurate to describe the TRC Test, as it is typically applied, as a limited version of the Societal Cost Test, because it includes the total resource costs, but not necessarily the total resource benefits.

The Societal Cost Test

The purpose of the Societal Cost Test is to indicate whether the benefits of distributed solar resources will exceed their costs from the perspective of society as a whole. This test should include all the costs and benefits of the Total Resource Cost Test, plus additional costs and benefits on society. The primary costs and benefits that are included in this test, when it is applied to distributed solar resources, are the environmental impacts and the net impacts on jobs and economic development.

The main advantage of the Societal Cost Test is that it provides the most comprehensive picture of the total costs and benefits of a distributed solar resource. Further, it is the only test that accounts for the benefits associated with a jurisdiction's energy policy goals (beyond the goals of reducing utility system costs or solar customer costs).

The main limitation of the Societal Cost Test when used for utility resource planning is that it might place too much emphasis on societal impacts if it is the only test considered. If the societal impacts of distributed solar resources are particularly high relative to the utility system costs and benefits, this test might place undue emphasis on achieving energy policy goals over the goal of reducing electricity system costs. Another limitation of the Societal Cost Test is that it can

The Societal Cost Test is the only test that fully accounts for a jurisdiction's energy policy goals (beyond the goal of reducing costs).

[29] Some states have modified the TRC test to include a value for non-energy benefits.

be difficult to fully implement, as many externalities are difficult to fully monetize.

The Rate Impact Measure Test

The purpose of the Rate Impact Measure (RIM) Test is to indicate whether distributed solar resources will increase or decrease electricity rates (i.e., prices). This test is sometimes used to indicate the impacts on non-solar customers, because these customers might experience rate impacts as a result of generation from distributed solar facilities. However, as explained more below, the RIM Test has several fundamental flaws and should not be used to evaluate rate impacts. Instead, a more comprehensive rate and bill impact assessment should be performed (as discussed in the following chapter).

Under the California Standard Practice Manual, the RIM Test includes the same costs and benefits included in the Utility Cost Test, plus the addition of "lost revenues." Lost revenues are caused by the reduced electricity consumption of solar customers, and are equal to the amount of revenues that utilities need to recover from non-solar customers in order to recover the fixed costs embedded in electricity rates.[30] However, these lost revenues are simply an artifact of recovering the same amount of revenues over fewer sales, and are not a new cost to the utility system.

The main (and only) advantage of the RIM Test is that it indicates whether a resource will increase or decrease electricity rates on average over the long term. Unfortunately, it fails to provide other useful information regarding rate and bill impacts.

One of the main limitations of the RIM Test is that it conflates cost-effectiveness and cost-shifting. These are two separate effects that can only be fully understood with separate analysis. Cost-effectiveness analyses should include only future costs, and should seek ways to minimize those future costs (along with achieving other policy goals). The RIM Test includes lost revenues, which are a result of historical costs (i.e., sunk costs) that are embedded in electricity rates. These costs would exist with or without distributed solar, and therefore are not a new cost to the utility system caused by distributed solar.

The main limitation of the RIM Test is that it conflates cost-effectiveness with cost-shifting. These are two separate effects that can only be fully understood with separate analysis.

Combining future costs and historical costs in one test makes it difficult to understand either cost-effectiveness or cost-shifting. It is also inconsistent with standard microeconomic theory, which requires that sunk costs not be included in cost-effectiveness analyses.[31]

Further, the RIM Test does not provide the information that utilities and regulators need to assess the magnitude of rate impacts caused by distributed solar resources. This test simply indicates whether rates will increase or decrease as a result of these resources. A RIM Test might result in a benefit-cost ratio of 0.9, for example, but this does not provide any indication of whether the rate impact is

[30] The lost revenues include the costs associated with historical investments in electricity infrastructure, including a financial return on those investments.

[31] If sunk costs are included, they should be included in both the base case (without distributed solar) and the case with distributed solar, which leads them to cancel each other out.

significant or *de minimus*. In other words, it provides no information regarding whether the rate impacts are likely to be reasonable, given the other benefits of distributed solar resources. A separate rate impact analysis, described in Section 5 below, can provide more useful metrics for this purpose, such as the percent change in rates or the average change in customer monthly bills.

The Participant Cost Test

The Participant Cost Test indicates whether a distributed solar resource is cost-effective from the perspective of the participant (the host solar customer). This test includes all of the impacts on the solar customer, but no other impacts. This test is fundamentally different from the other four tests described here in that the benefits are based on avoided electricity rates, not avoided utility system costs.

The Participant Cost Test should include all customer equipment, installation, and maintenance costs for the distributed solar facility, or solar lease payments (if applicable). The benefits should include all the benefits experienced by the solar customer, including reductions in electricity bills, as well as non-bill benefits such as reduced environmental impacts. In practice, these non-bill benefits to solar customers are rarely, if ever, estimated and included in cost-effectiveness analyses of distributed solar resources.

The main advantage of the Participant Cost Test is that it provides an indication of the extent to which host customers would benefit from installing distributed solar facilities. The main limitation of the Participant Cost Test is that it does not provide information regarding the impacts of distributed solar resources relative to other electricity resources, and provides no information regarding the impacts on the electricity system as a whole.

The extent to which customers are likely to adopt distributed solar resources will affect the need for future electricity resources, including generation, transmission, and distribution facilities.

Nonetheless, the impacts on solar customer are connected to electricity resource planning in one important way. The extent to which customers are likely to adopt distributed solar resources will affect the need for future electricity resources, including generation, transmission, and distribution facilities. Therefore, customer adoption rates will affect the future resource scenarios that should be used in cost-effectiveness analyses. However, conventional application of the Participant Cost Test may not provide sufficient information regarding customer adoption, as there is little information directly linking the results of the Participant Cost Test to penetration rates. For this reason, calculating the customer payback period instead of, or in addition to, the Participant Cost Test provides a more useful and direct means of determining the extent to which customers are likely to install distributed solar resources.

4.3. Implications of the Tests for Distributed Resources

Jurisdictions should consider several perspectives, when assessing the cost-effectiveness of distributed solar resources. As noted above, each cost-effectiveness test provides different types of information. The key implications for each test for distributed solar are as follows:

- Utility Cost Test: This tests provides the simplest, most direct indication of the future costs and benefits of distributed solar resources on all customers as a whole. It is a fundamental metric used in utility resource decision-making, including integrated resource planning. Therefore, it should be one of the primary tests used to indicate cost-effectiveness of distributed solar resources.

- Total Resource Cost Test: This test attempts to indicate the future costs and benefits of distributed solar resources on the utility system and solar customers. However, it does not accurately capture the benefits to solar customers. Further, while it includes "total" resource costs, it does not include total resource benefits, particularly those related to energy policy goals. Therefore, this test should be used with caution, and with an understanding of its limitations, when assessing the cost-effectiveness of distributed solar resources.

- Societal Cost Test: This test provides the most comprehensive indication of future costs and benefits of distributed solar resources, including the impacts related to energy policy goals, such as promoting local jobs and economic development and reducing environmental impacts. Therefore, it should be one of the primary tests, along with the Utility Cost Test, used to indicate cost-effectiveness of distributed solar resources.

- Rate Impact Measure Test: This test is different from the other tests in that it attempts to measure cost-shifting and impacts on non-solar customers. However, this test conflates cost-effectiveness with cost-shifting, and therefore does not provide useful information regarding either. Therefore, it should not be used to indicate the cost-effectiveness of distributed solar resources. Instead, cost-shifting from distributed solar resources should be analyzed using separate rate impact analyses, as described in Section 5.

- Participant Cost Test: This test provides a relatively narrow indication of the future costs and benefits of distributed solar resources on solar customers only. It does not provide information regarding the cost-effectiveness of distributed solar resources relative to other electricity resources. In other words, it does not provide much useful information for the purpose of comparing future resource options. The solar participant's perspective, however, is useful for estimating the extent to which different policies will encourage the development of distributed solar resources. Analyses of customer payback periods and adoption rates, as described in Section 3, are more useful for this purpose than the Participant Cost Test.

In sum, jurisdictions should generally use Utility Cost Test and the Societal Cost Test to understand the impacts of distributed solar, while the TRC Test should be used only with caution. Cost-shifting should be addressed using a rate impact analysis, not the RIM Test. And the solar participant's perspective should be addressed using a customer payback period and adoption rate analysis.

It is also important to recognize that each jurisdiction can choose how much emphasis to place on any one of the tests. Those with a greater focus on reducing utility system costs should give more weight to the Utility Cost Test; while those with a greater focus on achieving other energy policy goals should give more weight to the Societal Cost Test.

4.4. Cost-Effectiveness Tests Example

The results of distributed solar cost-effectiveness analyses tend to vary considerably by jurisdiction, particularly because the retail rates and the avoided costs vary significantly, and because these studies often use different methodologies and assumptions when accounting for costs and benefits.

To show how the choice of cost-effectiveness test can impact the results of a study, we have chosen an example analysis and present the cost-effectiveness results from the utility system perspective, the total resource cost perspective, and the societal perspective. The purpose of this example is not to endorse any of the studies or draw any conclusions about cost-effectiveness in any one jurisdiction, but is simply intended to illustrate the points made above.

Figure 8 presents an example of the cost-effectiveness results for a city in Pennsylvania, based upon the Utility Cost Test.[32] It shows the long-term average costs to the utility system, relative to the long-term average benefits to the utility system. Results of the Utility Cost Test generally show that distributed solar resources are very cost effective. This is because a large portion of the resource cost—the equipment, installation, and maintenance costs—are borne by the host customer, not the utility or the other customers.

Figure 8. Cost-Effectiveness Results for the Utility Cost Test

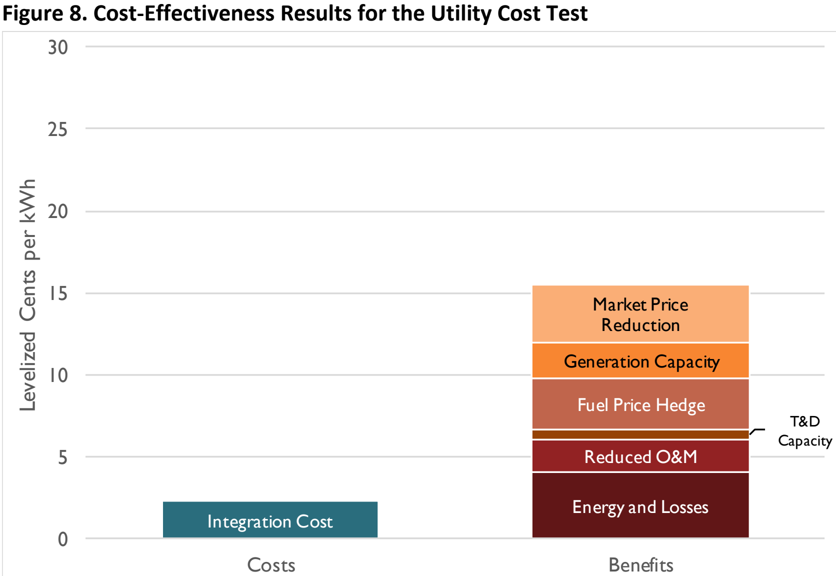


Figure 9 below presents the cost-effectiveness results for the same location, based upon the TRC Test. In this case the costs of the (privately financed) distributed solar facility are added to the utility costs, and the costs slightly outweigh the benefits.

[32] The utility and societal avoided cost results for Figure 8 through Figure 10 are derived from Perez, Norris, and Hoff (2012) for Pittsburgh.

Figure 9. Cost-Effectiveness Results for the TRC Test

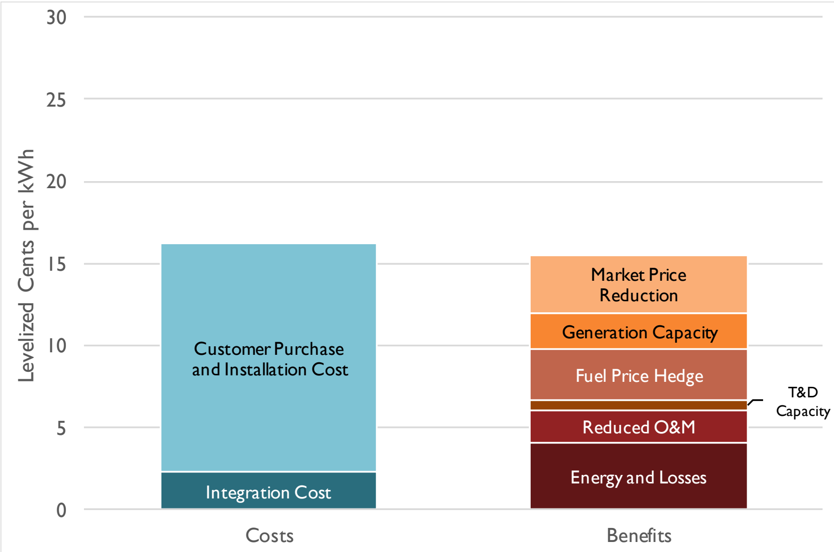
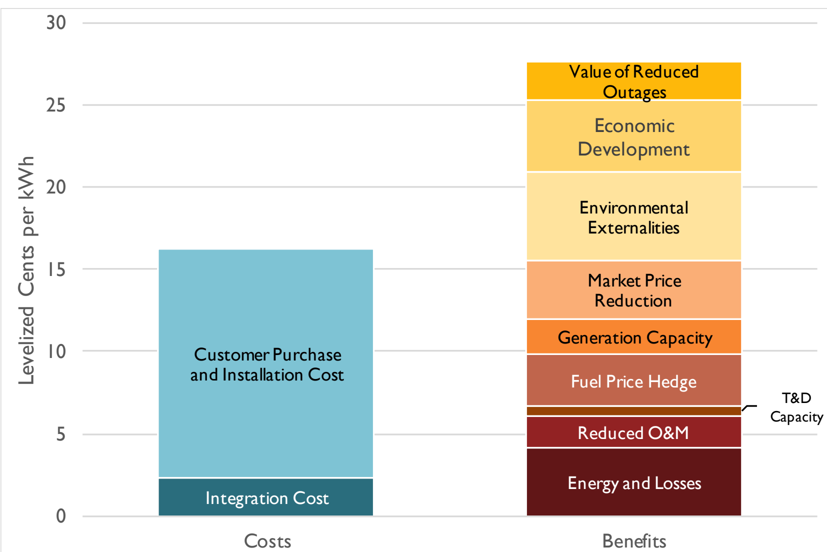


Figure 10 presents the cost-effectiveness results for the same location, based upon the Societal Cost Test. In this case the societal benefits are added to the utility system benefits.

Figure 10. Cost-Effectiveness Results from Recent Studies – Societal Cost Test[33]



As indicated in the figures above, the choice of test used to assess cost-effectiveness will have a significant impact on the outcome of the analysis—even within a single study using consistent methodologies and assumptions. This is why it is so important to understand the information that each test does, and does not, provide.

[33] Note that "societal" benefits may be defined differently from jurisdiction to jurisdiction. For example, economic development benefits (i.e., jobs) are not always included.

5. COST-SHIFTING FROM DISTRIBUTED SOLAR

The potential for cost-shifting from solar to non-solar customers is one of the most important issues facing utilities and regulators in essentially every jurisdiction addressing this topic. Therefore, cost-shifting warrants considerable attention and should be analyzed as concretely and comprehensively as possible. Although the RIM Test attempts to address cost-shifting, it does not provide sufficient information necessary to fully understand and address this important issue, as described in Section 4.2.

Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts, which results in higher bills for non-solar customers. Rates increase or decrease to reflect changes in electricity sales levels, changes in costs, or both. A comprehensive, long-term rate impact analysis will account for both of these effects, thereby providing the necessary information to help understand this critical issue.

When evaluating cost-shifting, it is important to also analyze both long-term and short-term rate impacts to understand the full picture. Generally, the benefits of distributed solar may not be realized for several years while a decrease in electricity sales occurs immediately. This can result in short-term rate increases, followed by long-term rate decreases. Thus a short-term rate impact analysis will not fully capture the impacts of distributed solar, and should not be performed without also evaluating long-term rate impacts.

In their most simplified form, electricity rates are set by dividing the utility's revenue requirement (in millions of dollars) over its sales (typically measured in kilowatt-hours).

$$Rates = \frac{Revenue\ Requirement}{Sales}$$

Thus rate impacts are primarily caused by two factors:

1. **Changes in costs:** Holding all else constant, if a utility's revenue requirement decreases, rates will decrease. Conversely, if a utility's revenue requirement increases, rates will increase. Distributed solar can avoid many utility costs, which can reduce utility revenue requirements. Distributed solar can also impose costs on the utility system (such as interconnection and distribution system upgrade costs.)
2. **Changes in electricity sales:** If a utility has to recover its revenues over fewer sales, rates will increase. This is commonly referred to as recovering "lost revenues" and is an artifact of the decrease in sales, not any change in actual costs incurred by the utility. Rather, the rate increase is due solely to the *distribution* of costs among solar and non-

solar utility customers. This impact is therefore only relevant to a rate impact analysis, which captures distributional impacts, not a cost-benefit analysis.[34]

Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors. If in one year distributed solar decreases the utility's revenue requirement by a larger percentage than sales decrease, rates can decline.[35] In reality, cost reductions may not reduce a utility's revenue requirement substantially in the near-term for two reasons.

First, in the short-term, the utility will still have to recover its sunk costs—the investments that the utility made in the past and amortized over many years.[36] These sunk costs will not be reduced by distributed solar, but will continue to be recovered through the utility's revenue requirement until they have been fully depreciated. Thus a decrease of 5 percent in next year's costs will not necessarily result in a decrease of 5 percent in total revenue requirements, since a large portion of a utility's revenue requirement stems from the recovery of historical investments.

The benefits of distributed solar may not be realized for several years while a decrease in sales occurs immediately. For this reason, both a long-run and a short-run analysis of rate impacts offer valuable information.

Second, distributed solar can help to avoid certain utility investments, and these avoided costs should be accounted for in a cost-benefit analysis. In the long run, if the average net avoided costs to the utility system (in dollars per kilowatt-hour) are equal to the credit received by the solar customer, then no cost-shifting over the study period is expected to occur.[37] If the net avoided costs are less than the credit received by the solar customer, rates will increase and cost-shifting will occur. Similarly, if net avoided costs are greater than the credit received, then a reduction in rates may occur.

These potential impacts are illustrated in the figure below. The column on the left shows the magnitude of the net utility system costs avoided by each kilowatt-hour of solar generation. For a net metered customer, the credit is equal to the retail rate. If the net avoided costs are lower than the retail rate (the middle bar), then each kilowatt-hour of solar generation will result in lost revenues to the utility that

[34] Cost-benefit analyses generally ignore distributional impacts, adhering instead to the Kaldor-Hicks efficiency criterion. This criterion focuses on maximizing total net benefits so that, in theory, any losers could be compensated and made no worse off than they were before. Although cost-benefit analyses can be made to incorporate "distributional weights" to account for equity concerns, this is difficult to do and rarely done in practice. A rate and bill impact analysis offers a means of assessing distributional impacts in a manner that is more transparent, comprehensive, and theoretically sound than the traditional application of the RIM Test.

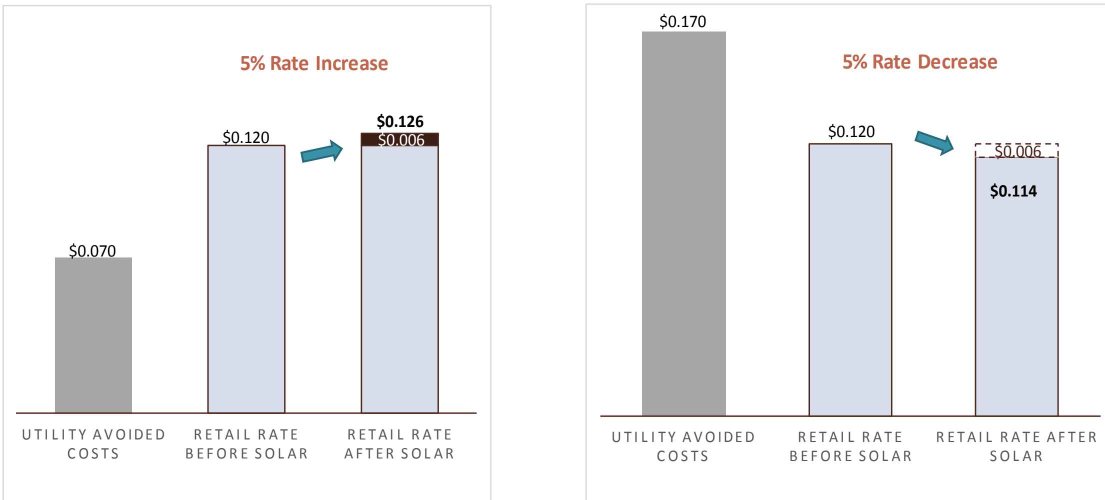
[35] Whether or not rates actually decrease is dependent upon whether the utility's revenues are recalculated and new rates are set. However, there may be a lag of several years before a new rate case commences and new rates are set.

[36] The utility is also allowed the opportunity to recover a return on its investments.

[37] The net avoided costs account for both the benefits and any additional costs imposed on the utility system by distributed solar.

increase rates, as shown by the right bar. Conversely, higher net avoided costs will reduce rates, as shown in the graph on the right.

Figure 11. Rate Impacts Associated with Different Levels of Net Avoided Costs



While the utility system avoided costs vary from jurisdiction to jurisdiction, many recent studies have estimated levelized avoided costs in excess of the retail rate, on a long-term levelized basis.[38] For each state where the avoided costs exceed the retail rate, distributed solar will likely lead to a reduction in rates over the long-term, and vice versa.[39]

As noted above, however, the timing of any benefits to the utility system is important to include in a rate impact analysis. Distributed solar will not help to defer or avoid capacity upgrades when no upgrades are planned for the near term. In time, generation, transmission, or distribution capacity upgrades may eventually be needed, and distributed solar can help to defer or avoid these investments, particularly when such investments are driven by additional load growth.[40] However, such benefits will only help to reduce revenue requirements in the years that they would have otherwise occurred.

Rate impacts should be presented in meaningful terms, such as the percent change in rates, as well as the annual and monthly bill impacts per customer (i.e., in dollars per customer per month or year).

[38] See, for example, Norris et al. 2015; Stanton et al. 2014; Perez, Norris, and Hoff 2012; Beach and McGuire 2013b; Hallock and Sargent 2015.

[39] Because utility system investments are often lumpy, many jurisdictions will experience short-term rate increases, even though rates may decline over the long run.

[40] To the extent that solar generation reduces peak loads on the distribution system, new infrastructure (such as substation upgrades) may be deferred or even entirely avoided. Solar generation may also help to provide thermal performance benefits through reducing peak demand, minimizing system losses, and improving reactive demand compensation.

In sum, because the benefits of distributed solar may not be realized for several years while a decrease in sales occurs immediately, jurisdictions often experience short-term rate increases. For this reason, both a long-run and a short-run analysis of rate impacts offer valuable information, and a thorough analysis of rate impacts resulting from distributed solar should include both the long-term change in customer rates as well as the year-to-year impacts.

The manner in which the results of a rate impact analysis are presented are important. Rate impact results should be presented in meaningful terms, such as the percent change in rates, as well as the annual and monthly bill impacts per customer (i.e., in dollars per customer per month or year).

A rate impact analysis provides a critical piece of information for decision-makers when determining distributed solar policies. The analysis should be performed for the current set of distributed solar policies, as well as any new policy considered to determine the degree to which both short-term and long-term rates are affected. Ultimately, the objective is to strike a balance between encouraging cost-effective resource investments and preventing unreasonable rate impacts to non-solar customers. Decision-makers may choose to tolerate moderate short-term increases in rates in order to achieve long-term system cost reductions, or they may decide that rate impacts on non-solar customers need to be mitigated by implementing other policies specifically aimed at addressing these impacts. Policies designed to mitigate rate impacts may include changes to rate design, or other options discussed in Section 2.

6. Summary and Example of the Analytical Framework

6.1. Implementation Steps of the Analytical Framework

The results of the three analyses described above can be pulled together into a single framework that can be used to evaluate different distributed solar resource policies in a transparent, data-driven regulatory process.[41] The framework proposed here can be used to assess the impacts of different rate designs or solar compensation mechanisms on the development, cost-effectiveness, and cost-shifting resulting from the distributed solar resources. If one policy option indicates an unreasonable amount of cost-shifting, then alternative policies may be warranted to mitigate cost-shifting.[42] If, on the other hand, the policy option results in very little solar development, and will not allow the jurisdiction to meet its energy policy goals, then alternative policies may be warranted to increase solar development.

The framework proposed here includes several steps that decision-makers or other stakeholders can take to assess the implications of different distributed solar policies. These steps are summarized in Table 4.

Table 4. Steps Required to Assess Distributed Solar Policies

Step 1	Articulate state policy goals regarding distributed solar resources.
Step 2	Articulate all the existing regulatory policies related to distributed solar resources.
Step 3	Identify all of the new distributed solar policies that warrant evaluation.
Step 4	Estimate the customer adoption rates under current solar policies, and new solar policies.
Step 5	Estimate the cost-effectiveness of distributed solar under current policies and new policies.
Step 6	Estimate the extent of cost-shifting under current solar policies, and new solar policies.
Step 7	Use the information provided in the previous steps to assess the various policy options.

6.2. Example Application of the Framework

An example will help to illustrate how a jurisdiction might apply the framework:

Step 1—Policy Goals: Consider a jurisdiction that has articulated a desire to promote cost-effective renewable distributed energy resources, to the extent that rate impacts are not unreasonable. Although current penetration levels of distributed solar are only at 1 percent, there is concern that rate impacts

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[41] See for example "Good Process" letter to Travis Kavulla, signed by 32 consumer, low-income, environmental and technology-specific advocates, June 23, 2016, available at http://blogs.edf.org/energyexchange/files/2016/06/Good-Rate-Design-Process-Letter-to-NARUC.pdf

[42] Such policies could include solar programs targeted to low-income individuals, reductions in solar generation credits, reductions in solar carve-out targets, or rate design options such as time-of-use rates or minimum bills. It is also important to understand how rate impacts may change over time. For example, short-term rate increases may be followed by long-term rate decreases. In such cases the mitigating policies should be chosen carefully to avoid losing the long-term rate reduction benefits.

will grow large in the near future under current net metering practices.

Step 2—Articulate Existing Regulatory Policies: The hypothetical jurisdiction currently has full net metering, i.e., residential solar customers are compensated at the hypothetical utility's variable rate of $0.14 per kilowatt-hour, but solar customers are also subject to a non-bypassable fixed charge of $5 per month. Solar customers do not receive any other incentives other than the current federal investment tax credit of 30 percent.

Step 3—Identify Policies that Warrant Evaluation: The jurisdiction wishes to continue net metering, but is considering changes to its current flat rate design, which will impact the magnitude of net metering credits. Alternatives being considered include time-of-use rates and demand charges. A time-of-use rate sets different energy rates for different periods of the day (e.g., off-peak, peak, and shoulder periods).

A demand charge reduces the energy charge but adds a charge based on the maximum amount of energy used during the month during any one period (typically measured on an hourly or 15-minute basis). By changing the energy rate, a demand charge impacts the degree to which solar customers can reduce their bills through solar generation, and thereby also affects the degree of cost-shifting.

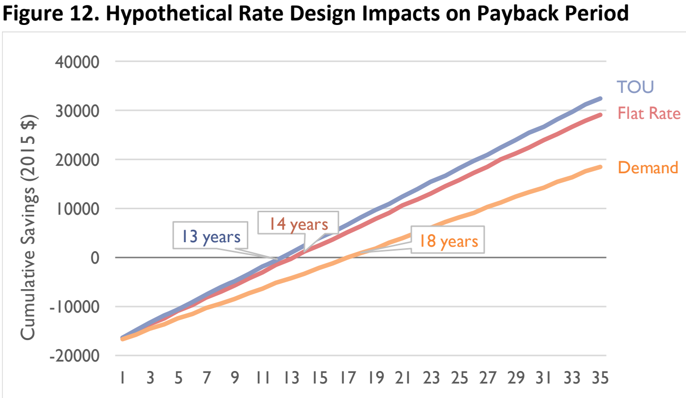
The rate design alternatives analyzed in this example are summarized in the table below, and were developed to be revenue neutral based on a hypothetical jurisdiction's customer usage patterns. (Further details are provided in Appendix B: Modeling Assumptions).

Table 5. Rate Design Policy Options Analyzed

Policy	Rate Design
Flat Rate	$0.14/kWh $5 fixed charge
TOU	$0.155/kWh Peak (9 am - 8:59 pm) $0.110/kWh Off-peak (9 pm – 8:59 am) $5 fixed charge
Demand Charge	$0.11/kWh $10/kW (based on maximum hour of month) $5 fixed charge

Step 4—Analyze Customer Adoption: As shown in the Figure 12 below, moving distributed solar customers from the flat rate to the TOU rate results in a decrease in the payback period from 14 years to 13 years, while a demand charge increases the payback period to 18 years.

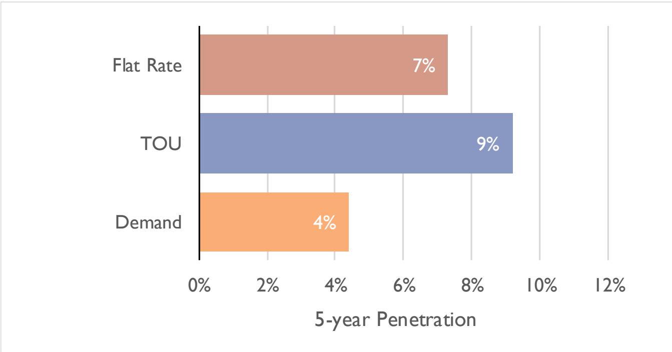
Figure 12. Hypothetical Rate Design Impacts on Payback Period



Using these payback periods and NREL's market penetration curves, five-year penetration rates can be estimated. We note that the payback periods assumed here are based on generic market penetration curves and may not reflect a jurisdiction's actual experience.[43]

Because of its shorter payback period, the TOU rate has the highest estimated five-year penetration rate, resulting in 9 percent of residential customers adopting distributed solar. Under the flat rate, penetration reaches 7 percent of residential customers, while under the demand charge, the percent of residential customers adopting solar reaches only 4 percent after five years. These estimated five-year penetration rates are shown in Figure 13.

Figure 13. Hypothetical 5-Year Penetration Rates

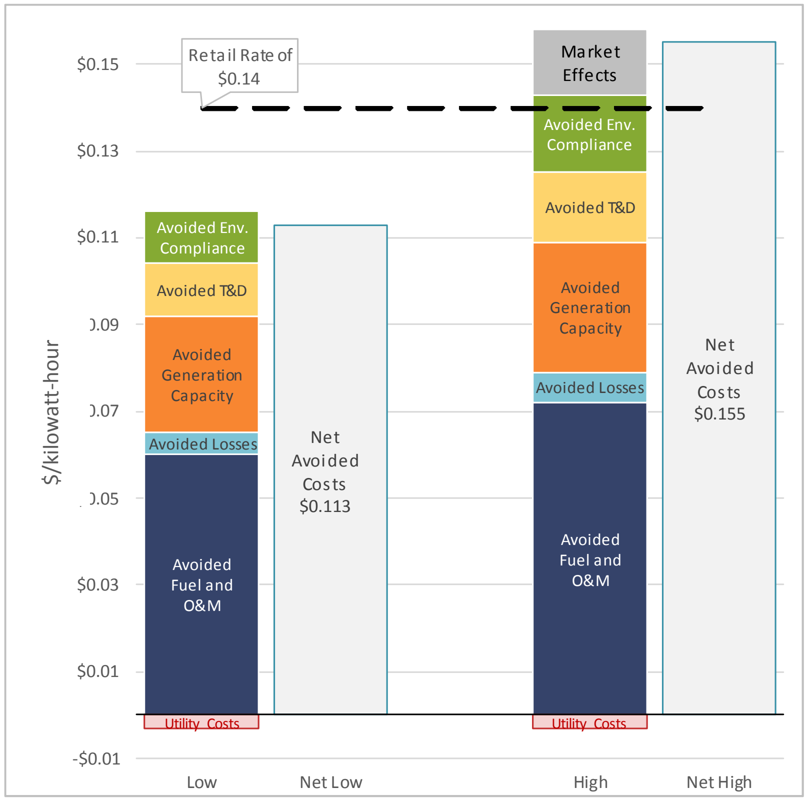


Step 5—Evaluate Cost Effectiveness: The avoided costs associated with distributed solar can vary significantly from jurisdiction to jurisdiction, and may change over time. For illustrative purposes, we discuss the results of two hypothetical avoided cost scenarios, one with net avoided utility system costs higher than the current retail rate of $0.14 per kilowatt-hour, and the other with net avoided costs that are lower than the retail rate, as shown in Figure 14 below.[44]

[43] We recommend that each jurisdiction conduct its own analysis of likely market penetration, and also consider the effect of alternative solar financing models (such as third-party leases). Further, we reiterate that the Bass Diffusion Model described in Section 3 does not account for the affordability of a technology. As the price of solar declines, customer adoption may surpass prior estimates.

[44] These avoided cost assumptions do not include any societal benefits or participant benefits. The environmental benefits that are included are those that would be incurred by the utility to comply with environmental regulations (such as NO_X, SO_X, and the Clean Power Plan). We have also subtracted out a small amount of utility costs (administrative or integration costs) to arrive at the net avoided costs. The magnitude of these costs and benefits is likely to change at higher penetrations, and thus must be re-evaluated frequently.

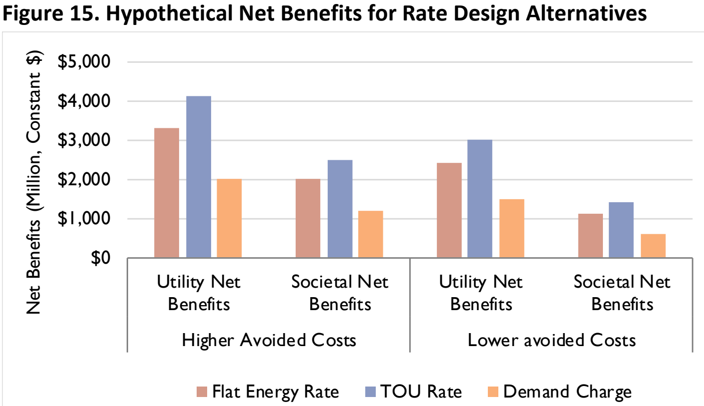
Figure 14. Hypothetical Low and High Avoided Costs



Cost-effectiveness results are presented in Figure 15 for the Utility Cost Test and the Societal Cost Test. Under both higher and lower avoided cost assumptions, each rate design analyzed exhibits positive net benefits. As discussed above, the Utility Cost Test is expected to result in positive net benefits, since the host customer's cost of installing a solar system is not included in the test. The Societal Cost Test may or may not result in positive net benefits, depending on the magnitude of any utility system or societal benefits (such as avoided environmental externalities.)[45]

The greatest net benefits are associated with the TOU rate, largely because the TOU rate results in the highest levels of solar adoption. The lowest net benefits are associated with the demand charge, which has relatively low customer adoption levels.

Figure 15. Hypothetical Net Benefits for Rate Design Alternatives



Step 6—Analyze Cost-Shifting: Bill impacts for non-solar customers are shown in Figure 16. All rate designs result in lower bills for non-solar customers in the scenario with higher avoided costs. These lower bills are shown as negative numbers in the graph and indicate that solar customers are providing a

[45] In this report, for illustrative purposes, the Societal Cost Test includes a relatively low value of $0.01 per kWh in hypothetical avoided environmental externality benefits.

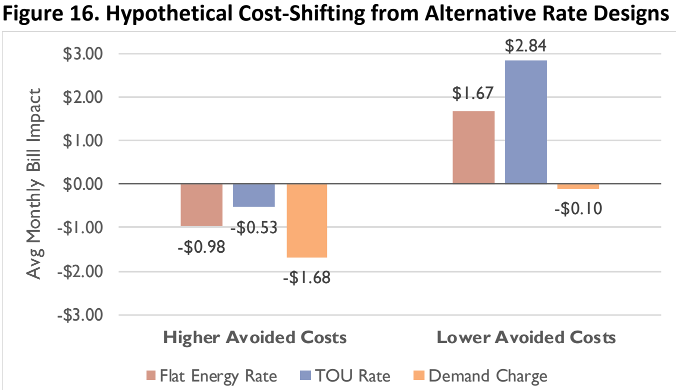
net benefit to both the system and to non-solar customers.) In the scenario with lower avoided costs, bills for non-solar customers are expected to increase for the flat rate and the TOU rate.

The results of lower bills for non-solar customers is expected under the higher avoided cost scenario, as the average avoided costs slightly exceed the retail rate. When avoided costs exceed the value of the credits received by solar customers, the reductions in utility costs offsets any rate increase that would occur due to lost revenues.

Under the lower avoided cost scenario, bill increases are expected because the average avoided costs are less than the bill credits received by solar customers under the flat rate and the TOU rate. The flat rate credit of $0.14 per kilowatt-hour exceeds the average avoided cost of $0.113 per kilowatt-hour, while the time-of-use rates and the peak time period definition (9 am – 9 pm) result in solar generation being compensated primarily at $0.155 per kilowatt-hour. Bill increases under the TOU rate are compounded by the fact that the TOU rate incentivizes greater solar adoption than under the flat rate, leading to higher overall penetration levels.

In the case of the demand charge, the compensation rate for solar customers is relatively low, only just slightly exceeding the lower avoided cost level. Further, solar generation generally does not reduce a solar customer's billed demand significantly, resulting in solar customers paying a similar demand charge as non-solar customers. Because the demand charge reduces solar customers' bill savings, penetration remains relatively low. For these reasons, cost-shifting from solar customers to non-solar customers does not occur under the demand charge (and in fact costs are being shifted in the other direction, from non-solar customers to solar customers).

Figure 16. Hypothetical Cost-Shifting from Alternative Rate Designs



Step 7—Assess Policy Options: The results of these alternative rate design policies are summarized in the tables below, which provide the opportunity to compare the net benefits to any cost-shifting impacts.

For example, assuming the higher avoided costs, the TOU rate results in the lowest bill reductions for non-solar customers. However, the TOU rate results in the highest net benefits, totaling more than $4 billion under the Utility Cost Test, and $2.5 billion under the Societal Cost Test. In contrast, the demand charge results in the greatest bill reductions, but the lowest net benefits and the lowest levels of solar penetration. The reason that the demand charge results in the greatest bill reductions is that costs are being shifted from non-solar customers to solar customers. In other words, solar customers are reducing system costs more than the value of their bill credits, under both the high and low avoided cost scenarios. Due to the relatively low penetration of 4 percent, however, the net benefits to the utility system are not as high as they would be under the flat rate or the TOU rate.

Table 6. Summary of Hypothetical Alternative Rate Design Policies—High Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$3,300	$1,800	$2,000	-$0.98	-0.7%
TOU (9 am – 9 pm)	13	9%	$4,100	$2,200	$2,500	-$0.53	-0.4%
Demand	18	4%	$2,000	$1,000	$1,200	-$1.68	-1.2%

Under the assumption of low avoided costs, the trade-off among policies becomes more pronounced. In this case, both the flat rate and the TOU rate result in bill increases for non-solar customers. (See Table 7, below.) However, these two rates also provide the greatest net benefits to the utility system and society. Decision-makers and stakeholders must then determine the appropriate trade-offs between bill decreases and overall net benefits. (Note that there are many ways that a TOU rate can be designed, as explored more in the following chapter.)

Table 7. Summary of Hypothetical Alternative Rate Design Policies—Low Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$2,400	$900	$1,100	$1.67	1.1%
TOU (9 am – 9 pm)	13	9%	$3,000	$1,100	$1,400	$2.84	2.0%
Demand	18	4%	$1,500	$500	$600	-$0.10	-0.1%

These results can be used by decision-makers and other stakeholders to compare distributed solar policies, and ideally to choose those that balance the potential rate impacts with cost-effectiveness and the state's energy policy goals. Further, the results can be used to establish appropriate penetration thresholds for future review of solar policies.

Decision-makers and stakeholders may differ in their choice of preferred policy options, but the framework described in this report will serve to make deliberations transparent and well informed.

7. Further Examples

To illustrate how various policies may affect solar penetration, cost-effectiveness, and cost-shifting, we have modeled several additional scenarios, using the hypothetical low and high avoided cost estimates introduced above. Each jurisdiction has its own unique characteristics in terms of avoided costs, customer usage patterns, solar output, rate structures, and incentives for solar PV. For this reason, the results below cannot be assumed to apply broadly to all jurisdictions, although the general direction of the results may hold in many parts of the country.

7.1. TOU Rate Sensitivity

Time-of-use rates can be designed in many ways. They can consist of long peak periods (such as the 9 am–9 pm example above), or the peak period can be narrow. The differential between the peak and off-peak rate also plays a critical role in determining the magnitude of bill credits received by solar customers. TOU rates can provide more efficient price signals than flat rates if they are designed so that the prices associated with each period reflects the relative cost of providing electricity during those hours. Prices are typically highest during periods of high demand, when the most expensive generators must be used to provide power.

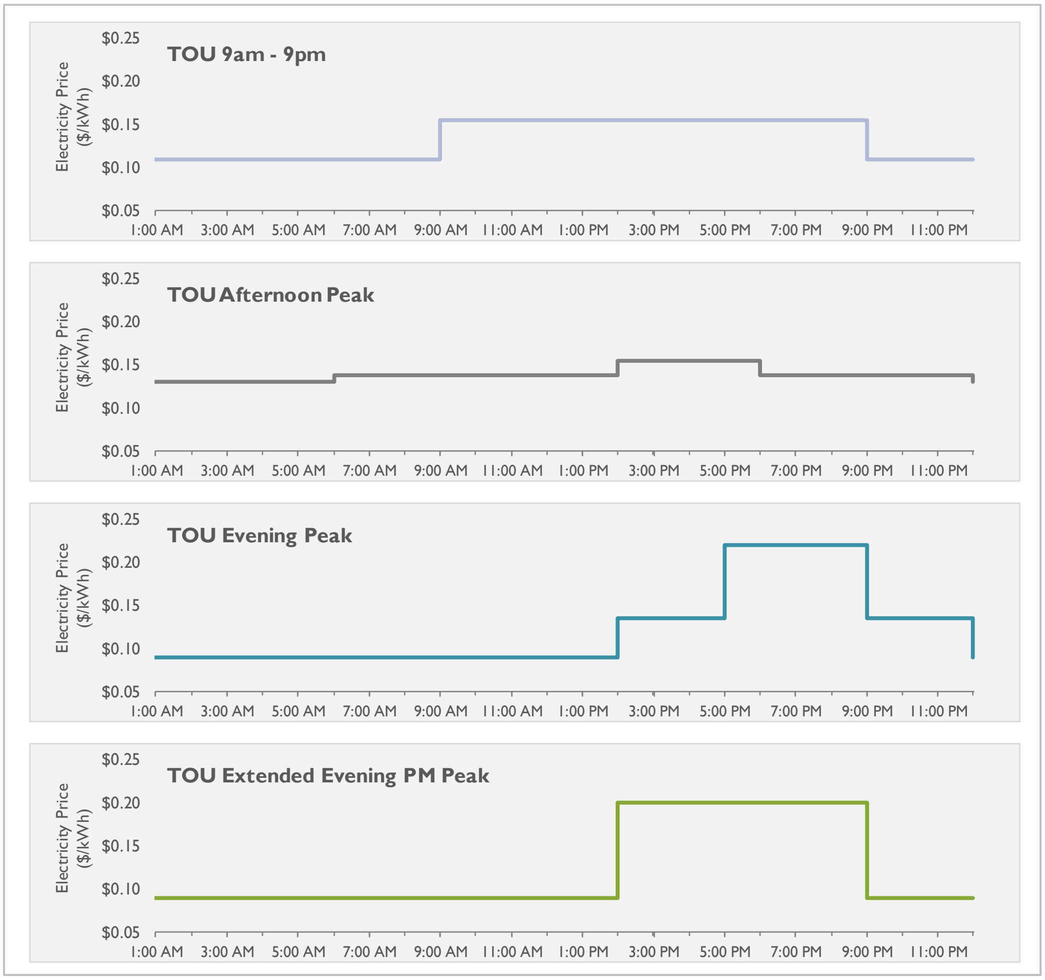
Step 3—Identify Policies that Warrant Evaluation: To continue our example from above, suppose that the hypothetical jurisdiction wishes to examine the range of impacts that the design of TOU rates can have on solar penetration, cost-effectiveness, and cost-shifting. To do so, the jurisdiction conducted a sensitivity analysis using several variations of a TOU rate, shown in the table below.

Table 8. TOU Rate Alternatives Analyzed

TOU Rate Name	Hours	Rate Design
TOU Afternoon Peak	Peak: 2:00 pm – 5:59 pm Shoulder: 6:00 am – 1:59 pm, 6:00 pm – 11:59 pm Off-Peak: 12:00 am – 5:59 am	Peak: $0.155 Shoulder: $0.138 Off-Peak: $0.130
TOU Evening Peak	Peak: 5:00 pm – 8:59 pm Shoulder: 2:00 pm – 4:59 pm, 9 pm – 11:59 pm Off-Peak: 12:00 am – 1:59 pm	Peak: $0.220 Shoulder: $0.135 Off-Peak: $0.090
TOU Extended PM Peak	Peak: 2:00 pm – 8:59 pm Off-Peak: 9:00 pm – 1:59 pm	Peak: $0.200 Off-Peak: $0.090

These TOU options are illustrated in the figure below:

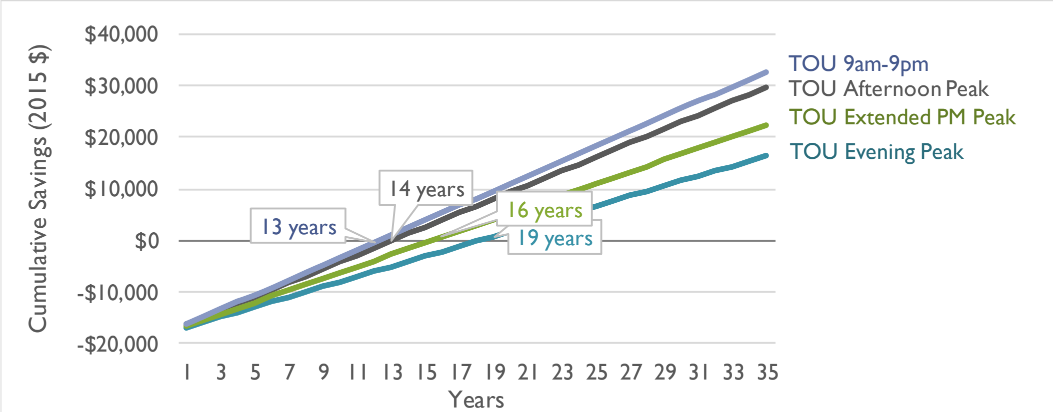
Figure 17. TOU Rates Modeled



Step 4—Analyze Customer Adoption: The payback periods shown below demonstrate how changes to TOU rate peak/shoulder/off-peak periods and their associated prices can significantly impact distributed solar economics. For comparison purposes, the TOU rate from Section 6 (with a peak period from 9 am – 9 pm) is also included.

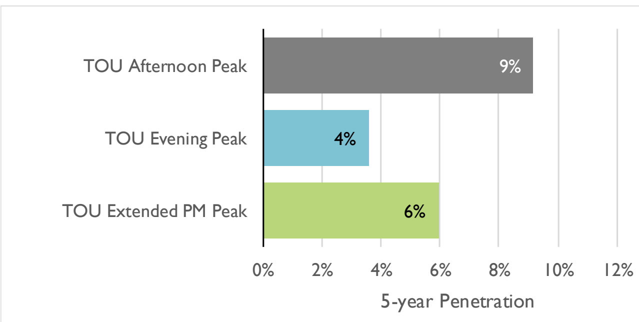
The TOU rate from the previous example (9 am – 9 pm) has a payback period of 13 years, while the three new TOU rates analyzed have payback periods that range from 14 to 19 years. The TOU Extended Evening Peak (with a peak from 5 pm – 9 pm) has the longest payback period, as it results in net metered solar customers being credited for their generation primarily at the off-peak rate or shoulder rates, since the peak period does not begin until solar generation is waning.

Figure 18. Hypothetical Payback Periods for TOU Rate Alternatives



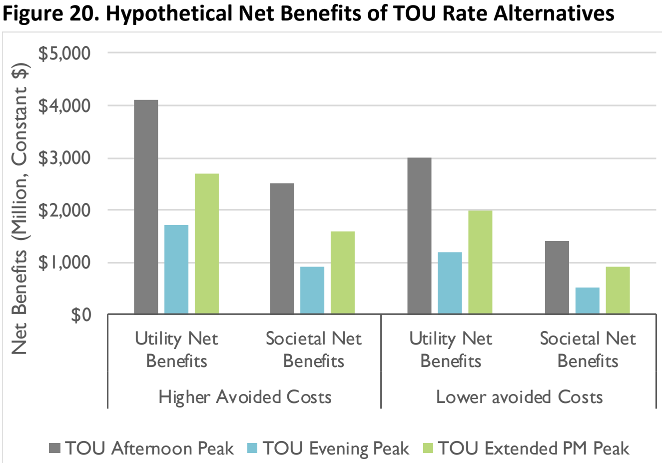
The five-year penetration levels associated with the TOU Afternoon Peak design is 9 percent, while the penetration level for a TOU Extended PM Peak design is 6 percent, while the TOU Evening Peak results in a five-year penetration level of only 4 percent. These penetrations are shown in Figure 19.

Figure 19. Hypothetical 5-Year Penetration Rates



Step 5—Evaluate Cost-Effectiveness: As in the previous chapter, the cost-effectiveness results are presented under both higher and lower avoided cost estimates. Again, all rate options exhibit positive net benefits, with the greatest net benefits associated with the rate with the highest penetration of solar (the TOU Afternoon Peak design). These results are shown in Figure 20 below.

Figure 20. Hypothetical Net Benefits of TOU Rate Alternatives

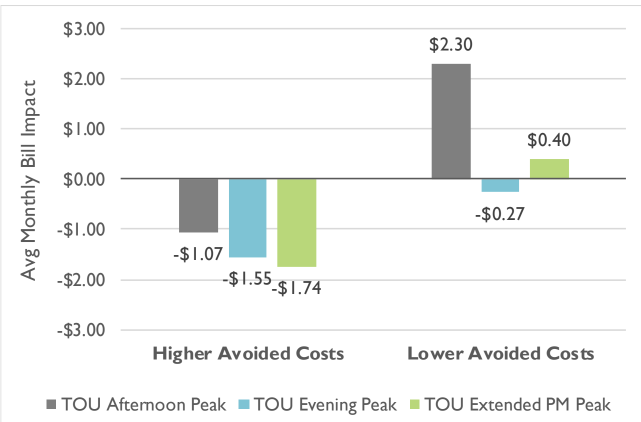


Step 6—Analyze Cost Shifting: Bill impacts for non-solar customers vary significantly by TOU rate design, as shown in Figure 21. Under the higher avoided cost scenario, all TOU rates result in bill reductions for non-solar customers, with the greatest bill reductions stemming from the Extended PM Peak design. Under the lower avoided cost scenario, the TOU rate with an evening peak period still results in bill reductions for non-solar customers, since the average bill credit for solar generation is less than the average avoided cost.

In contrast, the bill increase associated with the TOU Afternoon Peak rate is more than $2 per month, due to the fact that this rate aligns well with solar generation and results in the highest penetration levels. Thus a large portion of solar generation is compensated at a peak period rate that exceeds the levelized avoided cost value under the lower avoided cost scenario.

The Extended PM Peak rate (with a peak from 2 pm to 9 pm) results in much lower bill increases ($0.40 per month), while still achieving moderate five-year penetration levels of 6 percent.

Figure 21. Hypothetical Bill Impacts of TOU Rate Alternatives



Step 7—Assess Policy Options: The overall hypothetical impacts of the TOU rates analyzed are summarized in the tables below.

Table 9. Summary of Hypothetical TOU Rate Impacts – High Avoided Cost

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
TOU Peak 2pm-6pm	13	9%	$4,100	$2,200	$2,500	-$1.07	-0.7%
TOU Peak 5pm-9pm	14	7%	$1,700	$800	$900	-$1.55	-1.1%
TOU Peak 2pm-9pm	16	6%	$2,700	$1,400	$1,600	-$1.74	-1.2%

Table 10. Summary of Hypothetical TOU Rate Impacts – Low Avoided Cost

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
TOU Peak 2pm-6pm	13	9%	$3,000	$1,100	$1,400	$2.30	1.6%
TOU Peak 5pm-9pm	14	7%	$1,200	$400	$500	-$0.27	-0.2%
TOU Peak 2pm-9pm	16	6%	$2,000	$700	$900	$0.40	0.3%

7.2. Fixed Charges and Minimum Bills

In recent years, many utilities have proposed to increase fixed charges for residential customers, in some cases substantially (Whited, Woolf, and Daniel 2016). By increasing the fixed portion of the bill, fixed charges reduce the energy rate, thereby also reducing bill credits for net metered customers. As an alternative to increasing the fixed charge, some jurisdictions have adopted a minimum bill. Minimum bills only take effect if a customer's bill would fall below the minimum amount; otherwise the minimum bill does not apply. Unlike a fixed charge, a minimum bill does not reduce the energy rate, thereby enabling net metered customers to receive the same credit per kilowatt-hour after they have paid the minimum bill.

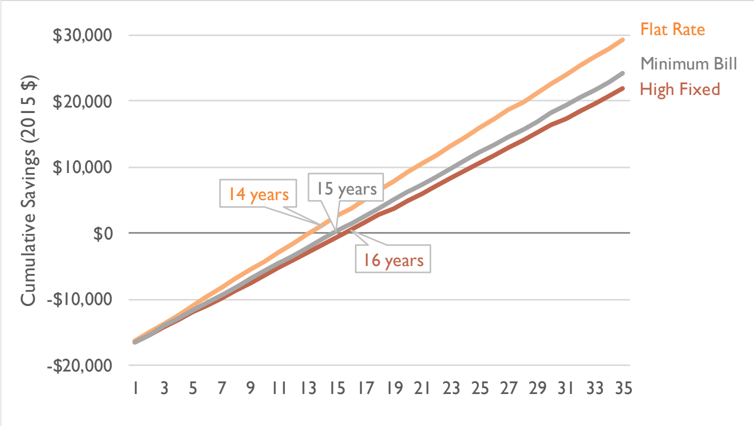
Step 3—Identify Policies that Warrant Evaluation: This example explores the impacts of increasing the fixed charge to $25 per month or setting a minimum bill at $25 per month for the hypothetical jurisdiction. All rates are designed to be revenue neutral.

Table 11. Flat Rate, Higher Fixed Charge, and Minimum Bill Designs Analyzed

Policy	Rate Design
Flat Rate	Flat energy charge of $0.14 Fixed charge of $5
Higher Fixed	Flat energy charge of $0.12 Fixed charge of $25
Minimum Bill	Flat energy charge of $0.145 Minimum bill of $25 No fixed charge

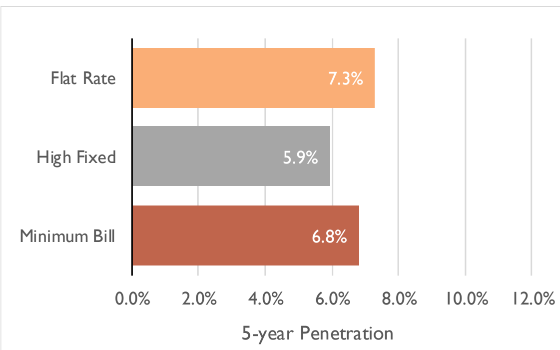
Step 4—Analyze Customer Adoption: Both the minimum bill and the higher fixed charge increase the payback period for net metered customers. Under the minimum bill, the payback period increases from 14 years to 15 years, while the higher fixed charge extends the payback period to 16 years.

Figure 22. Hypothetical Payback Periods for Flat Rate, Higher Fixed Charge, and Minimum Bill



Although the minimum bill increases the payback period by a year, it is not enough to significantly alter the five-year penetration rate. Under the minimum bill, the five-year penetration declines only slightly from 7.3 percent to 6.8 percent.[46] Under the high fixed charge, penetration declines to 5.9 percent.

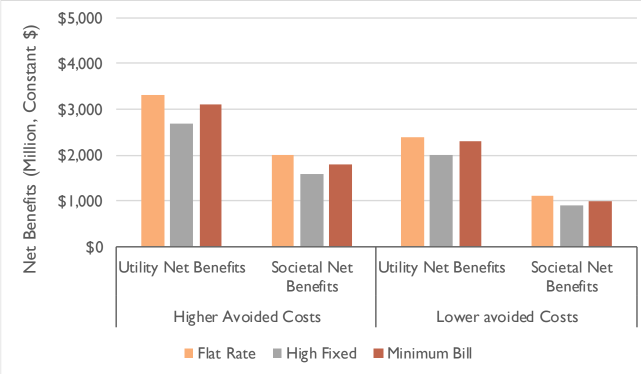
Figure 23. Hypothetical 5-Year Penetration Rates



Step 5—Evaluate Cost-Effectiveness: All three rate designs are cost-effective, but the flat rate exhibits the highest net benefits, followed by the minimum bill, as shown in Figure 24. This is in part due to the flat rate and minimum bills result in higher penetrations of solar than the high fixed charge.

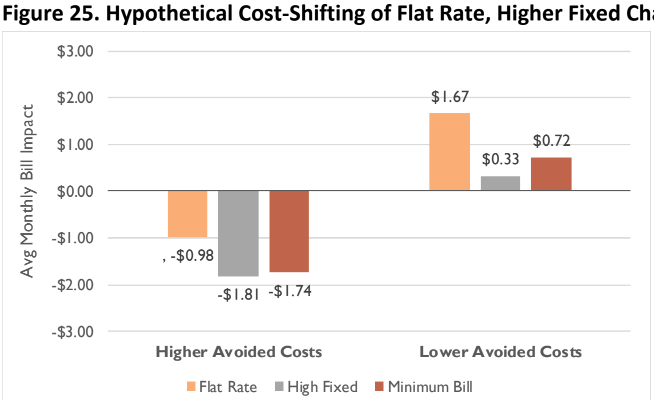
[46] Reported values are rounded.

Figure 24. Hypothetical Net Benefits of Flat Rate, Higher Fixed Charge, and Minimum Bill



Step 6—Analyze Cost-Shifting: As expected, by increasing the amount that solar customers must pay, the higher fixed charge and the minimum bill reduce potential negative impacts on non-solar customers. In the higher avoided cost scenario, the fixed charge and minimum bill result in nearly identical bill reductions for non-solar customers, despite the minimum bill enabling greater solar penetration. In the lower avoided cost scenario, the fixed charge reduces the monthly bill increase from $1.67 under the flat rate to only $0.33. The minimum bill also significantly reduces any bill increases for non-solar customers, reducing the average monthly bill increase to $0.72.

Figure 25. Hypothetical Cost-Shifting of Flat Rate, Higher Fixed Charge, and Minimum Bill



The combined results are presented in tabular format in the tables below.

Table 12. Hypothetical Summary of Alternative Compensation Results—High Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$3,300	$1,800	$2,000	-$0.98	-0.7%
High Fixed Charge	16	6%	$2,700	$1,400	$1,600	-$1.81	-1.2%
Minimum Bill	15	7%	$3,100	$1,600	$1,800	-$1.74	-1.2%

Table 13. Hypothetical Summary of Alternative Compensation Results—Low Avoided Costs

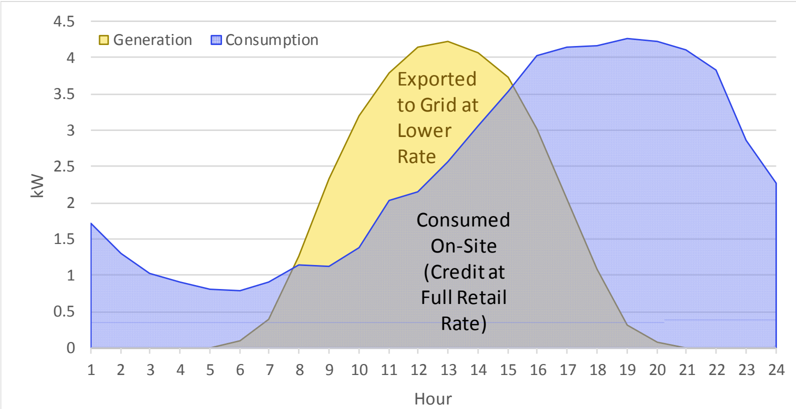
	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$2,400	$900	$1,100	$1.67	1.1%
High Fixed Charge	16	6%	$2,000	$700	$900	$0.33	0.2%
Minimum Bill	15	7%	$2,300	$800	$1,000	$0.72	0.5%

7.3. Alternative Compensation Mechanisms

Some jurisdictions are considering moving from traditional net metering (which provides one-to-one monthly bill credits to solar customers to offset their consumption) to alternative forms of netting. One form consists of netting net generation against consumption on a near-instantaneous basis, rather than at the end of the month. Solar generation that is not immediately consumed on-site is exported to the grid at a reduced rate. A similar concept is known as net billing, which still uses a monthly timeframe for netting, but compensates monthly excess generation at a reduced rate.

Instantaneous netting and net billing are therefore nearly identical, except that they conduct the netting over different time frames. Under net billing, if a customer generated 800 kWh and consumed 800 kWh over the course of the month, all generation would be credited at the retail rate. Under instantaneous netting, a customer would receive the full retail rate for much less of their generation if their load and generation profiles did not fully align. An example of this situation is shown in Figure 26, below, where the customer receives full compensation for only 70 percent of his or her generation on a particular day.

Figure 26. Example Compensation Under Instantaneous Netting



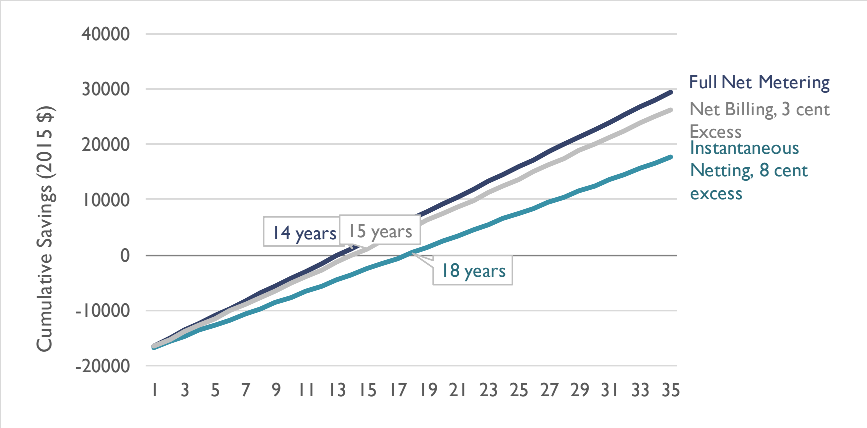
Step 3—Identify Policies that Warrant Evaluation: Suppose the hypothetical jurisdiction wishes to examine the impact of other compensation mechanisms, such as instantaneous net metering with reduced payment for any generation exported to the grid (e.g., $0.08 per kilowatt-hour of generation not consumed immediately at the customer's site), and net billing with reduced payment for monthly excess generation (e.g., $0.03 per kilowatt-hour for any generation that does not offset consumption when netting occurs at the end of the month.) These policies are summarized in the table below.

Table 14. Alternative Compensation Mechanisms Analyzed

Policy	Credit for Behind-the-Meter Generation	Credit for Generation Exported to Grid	Credit for Monthly Excess Generation
Full Net Metering	Full retail rate ($0.14)	Full retail rate ($0.14)	Full retail rate ($0.14)
Instantaneous Netting	Full retail rate ($0.14)	$0.08 for any generation not consumed immediately on-site	$0.08
Net Billing	Full retail rate ($0.14)	Full retail rate ($0.14) until generation exceeds consumption	$0.03

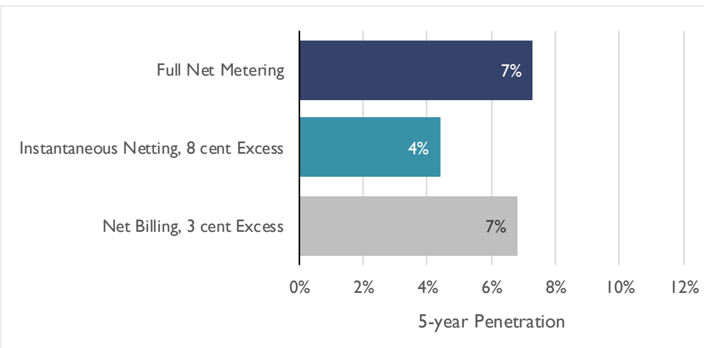
Step 4—Analyze Customer Adoption: A comparison of the payback periods associated with each of these options might reveal that the current full net metering arrangement has an estimated payback period of 14 years, a net billing arrangement with $0.03/kWh for excess compensation might only lengthen that payback period to 15 years, and instantaneous netting with $0.08/kWh for generation pushed onto the grid would extend the payback period to 18 years. This demonstrates the degree to which instantaneous netting can erode a solar customer's bill savings, even when the credit for exports is much higher than the monthly excess rate under net billing.

Figure 27. Hypothetical Payback Periods for Alternative Compensation Mechanisms



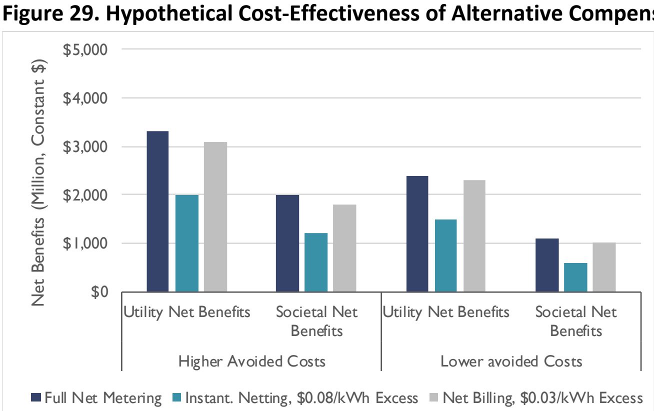
Based on market penetration curves, these payback periods would be expected to yield a five-year penetration rate of 7 percent under full net metering and under net billing, but only 4 percent under instantaneous netting.

Figure 28. Hypothetical 5-Year Penetration Rates



Step 5—Evaluate Cost-Effectiveness: Under both higher and lower avoided costs, each compensation policy is shown to be cost-effective, as demonstrated by positive net benefits (see Figure 29). However, the net benefits are highest for full net metering and lowest for instantaneous netting.

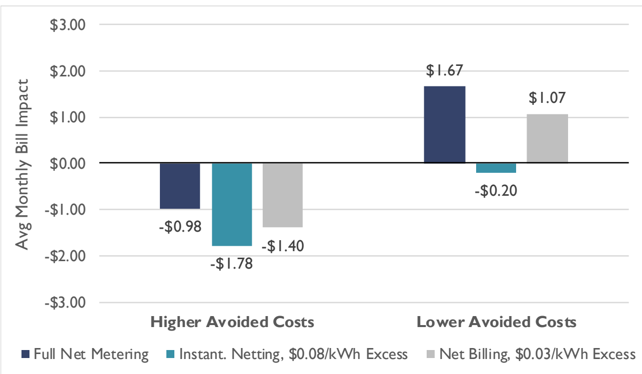
Figure 29. Hypothetical Cost-Effectiveness of Alternative Compensation Mechanisms



Step 6—Analyze Cost-Shifting: The extent to which distributed solar increases or decreases bills for non-solar customers is highly dependent upon three factors: the bill credits that the solar customer receives, the avoided costs to the utility system, and the percentage of customers that install distributed solar. We have again used both high and low estimates of avoided costs to illustrate the potential for cost-shifting at a hypothetical utility. As shown in the graph below, full net metering provides the greatest compensation to solar customers, thereby resulting in the highest penetration levels. Under the higher avoided costs scenario, this is not problematic, as the avoided costs outweigh the net metering credit (the retail rate), resulting in bill decreases of approximately $1 per month on average for non-solar customers. However, under the lower avoided cost scenario, bill increases of $1.67 per month can be expected for non-solar customers under full net metering.

Under the instantaneous netting scenario, solar penetration remains relatively low, at only 4 percent of residential customers. However, the avoided costs greatly exceed the bill credits in the higher avoided cost scenario, leading to bill reductions under both scenarios.

Figure 30. Hypothetical Penetration Levels and Bill Impacts of Alternative Compensation Mechanisms



Step 7—Assess Policy Options: Table 15 tables below provide a summary of the results of the alternative compensation mechanisms analyzed.

Table 15. Hypothetical Summary of Alternative Compensation Results—High Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Full Net Metering	14	7%	$3,300	$1,800	$2,000	-$0.98	-0.7%
Instantaneous Netting, 8 cent Excess	18	4%	$2,000	$1,000	$1,200	-$1.78	-1.2%
Net Billing, 3 cent Excess	15	7%	$3,100	$1,600	$1,800	-$1.40	-1.0%

Table 16. Hypothetical Summary of Alternative Compensation Results—Low Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	%	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	%
Full Net Metering	14	7%	$2,400	$900	$1,100	$1.67	1.1%
Instantaneous Netting, 8 cent Excess	18	4%	$1,500	$500	$600	-$0.20	-0.1%
Net Billing, 3 cent Excess	15	7%	$2,300	$800	$1,000	$1.07	0.7%

7.4. Conclusions Regarding Modeling Results

The illustrations above will not necessarily reflect the reality of any particular policy in any particular place. These examples are provided simply to illustrate the types of analyses that should be used to inform policy discussions. Nonetheless, based on our review of studies performed to date, as well as the illustrations in this report, the numbers suggest several general conclusions.

- First, payback period results are highly sensitive to the retail rate in place, as well as system cost and size assumptions. Increased fixed charges and demand charges can dramatically increase payback periods.
- Second, cost-effectiveness results are very sensitive to avoided cost estimates. Under the Utility Cost Test, distributed solar appears highly cost effective, while under the Total Resource Cost Test distributed solar is much less cost effective. However, the TRC Test does not fully account for participant benefits (bill reductions). Under the Societal Cost Test, distributed solar is often, but not always, cost effective. The Societal Cost Test helps indicate the extent to which distributed solar will meet certain state policy goals.
- Third, cost-shifting results are very sensitive to avoided cost estimates. In general, the extent of cost-shifting will depend upon the relationship between the net avoided costs[47] to the utility system and the credit that the solar customer receives. At low penetrations, cost-shifting is likely to be minimal.

[47] Net avoided costs consist of both the benefits (avoided costs) to the utility system, as well as any increase in system costs caused by distributed solar.

8. Scope of This Report and Further Research

8.1. Scope and Limitations of this Report

Developing balanced distributed solar policies requires consideration of many complex economic, technical, and policy issues. The economic framework proposed in this report will help provide important information for sorting through many of these complex issues, but it is not intended to provide an answer to every question.

Each jurisdiction will need to consider several issues, in addition to those addressed here, to ensure that its distributed solar policies will meet its goals and be in the public interest. For example, decision-makers and utilities should be mindful of the technical limitations of installing increasing amounts of distributed solar on the distribution grid, and the costs of doing so. As another example, decision-makers and utilities should be mindful that average avoided cost values obscure the locational variation of costs and benefits. These important considerations are beyond the scope of this study.

In addition, the illustrative analyses presented in this report are not intended to provide an indication of the results that will be experienced for any particular state or utility. The actual results are likely to be very sensitive to the specific conditions applicable to the utility territory in question. This is particularly true with regard to estimates about avoided costs, but is also true with regard to retail rates and customer load profiles. Thus, the illustrative analyses presented in this report should not be used to draw specific conclusions about any one state or utility. It is essential that each state or utility apply the framework proposed here based upon local conditions and assumptions, using the best information that is available.

Actual results are likely to be very sensitive to specific conditions applicable to the utility territory in question, particularly avoided costs.

Further, the illustrative analyses in this report include some simplifying assumptions that could affect the analytical results. With regard to cost-effectiveness, the analysis does not account for variation in avoided costs due to the timing or location of distributed solar generation. The customer adoption rates and models currently available in the literature are based on limited research and may not reflect accurately project customer adoption rates for every jurisdiction. With regard to cost-shifting and rate impacts, our analysis does not account for the extent to which costs could be allocated differently across classes as a result of high penetrations of distributed solar. Ideally, state-specific and utility-specific analyses will be able to improve upon these simplifying assumptions over time.

Recommendations for Next Steps and Further Research

As demonstrated by the illustrative results above, the analyses recommended in this report are highly dependent upon good data. For this reason, we strongly recommend that regulators encourage collaborative and transparent processes for estimating the avoided costs of distributed solar resources.

While there are many value-of-solar studies available today, there also remains considerable debate over avoided cost calculations and assumptions. Regulators should encourage utilities and other stakeholders to develop avoided cost estimates in a collaborative and transparent fashion. The six New

England states use this approach for developing avoided costs of energy efficiency resources, and a similar approach could be used to develop avoided costs for distributed solar resources.

In particular, we recommend that a collaborative approach be taken to develop standard avoided cost methodologies and data collection processes. Some of the most difficult avoided cost categories to estimate are:

- Avoided transmission and distribution costs of distributed solar resources.
- Locational value of distributed solar resources.
- Utility costs of integrating and supporting distributed solar generation on the distribution grid.

Regulators should encourage utilities and other stakeholders to develop avoided cost estimates in a collaborative and transparent fashion.

In addition, there are several avenues of further research that would be especially useful for states and utilities seeking to answer key questions in designing balanced distributed solar policies. These include:

- Customer adoption curves for distributed solar resources, and how such adoption curves vary by location or demographics (including income levels), and how third-party leases or subsidized loans impact the adoption curves.
- Analyses of the customer adoption, the cost-effectiveness, and the cost-shifting implications of community solar projects.
- Best practices for incorporating distributed solar resources into distribution system planning processes in order to reap the greatest net benefits.

9. Overall Conclusions

In setting distributed solar policies, utility regulators and state policymakers should seek to strike a balance between ensuring that cost-effective clean energy resources continue to be developed, and avoiding unreasonable rate and bill impacts for non-solar customers. Yet without a full understanding of how policy changes may affect both solar and non-solar customers, decision-makers risk implementing policies that are inappropriate for the jurisdiction's context.

While there are many analytical assessments of the likely cost-effectiveness of distributed solar resources, there are few analytical assessments of the extent to which distributed solar might result in cost-shifting to non-solar customers—even though this question is of great concern to stakeholders in every jurisdiction. Further, there are few analytical assessments of the extent to which different distributed solar policies are likely to impact the growth of distributed solar resources. Yet this is a central question that should be addressed when evaluating distributed solar policies.

To assist decision-makers in evaluating distributed solar policy options comprehensively and concretely, this report outlines a framework for evaluating distributed solar policies, which is summarized in the table below:

Table 17. Summary of Framework for Addressing Key Solar Policy Questions

Question	Analysis	Tools
Will the policy impact the adoption of distributed solar?	Development of distributed solar	Payback period analysis Penetration analysis
Will the policy result in net benefits to the utility system, to customers, and to society?	Cost-effectiveness	Utility Cost Test Societal Cost Test Total Resource Cost Test
To what extent does the policy mitigate or exacerbate any cost-shifting to non-solar customers?	Cost-shifting	Rate impact analysis Bill impact analysis

Using the results of the analyses presented above, decision-makers can review the projected impacts of various policy options to determine what course of action is in the public interest. Appropriate consideration of all relevant impacts will help decision-makers to avoid implementing policies that have unintended consequences or that fail to achieve policy goals. The analysis results can also help to determine the point at which certain distributed solar policies should be reevaluated or modified. It is critical, however, that the analyses be based on accurate inputs, particularly for avoided costs.

Given that each jurisdiction has its own policy goals and unique context, the ultimate policy decision reached by decision-makers may be different in each jurisdiction, even when based on the same analytical results. Nonetheless, the framework articulated above will provide decision-makers with the ability to balance protection of customers with achieving overarching policy objectives in a transparent, data-driven process.

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Appendix A: Generic Discovery Requests for Assessing Distributed Solar Policies

This section contains sample discovery questions designed to assist stakeholders obtain the key pieces of information that are required for conducting the analyses recommended in this report.

Note that a "typical residential PV system" may vary across utilities. It is recommended that the term either be specifically defined for the utility or that the utility be asked to define what it considers to be a "typical residential PV system" with regard to the questions asked and answered herein.

It is expected that some costs and avoided costs are constant, others only occur in the first year, and still others will vary throughout the years. Also note that these costs or avoided costs may be a function of the total quantity of residential PV expected to be on the utility system in each future year.

System Information

All questions refer to customers in the utility system within the state/territory.

General

1. Please provide the number of residential customers.
2. Please provide the forecasted number of residential customers for each year of the study period.
3. Please provide the complete tariff or tariffs applicable to non-PV residential customers.

PV

4. Please provide the current number of residential PV customers.
5. Please provide the current solar PV nameplate capacity of residential PV on the utility system.
6. Please provide any studies or forecasts for the number of residential PV customers for each year of the study period.
7. Please provide any studies or forecasts for the total expected solar PV nameplate capacity of all the residential PV systems for each year of the study period.
8. Please provide the complete tariff or tariffs applicable to residential customers with interconnected PV systems.

Cost Information

General

9. To the extent that the utility has modeled a typical residential PV system for any cost or benefit calculations, please provide the detailed assumptions for the typical residential PV system, including

    a. Latitude and longitude;

    b. DC system size;

    c. Array tilt;

    d. Array azimuth;

    e. System loss percentage; and

    f. Inverter efficiency.

10. To the extent that the utility has modeled a typical residential PV system's hourly output for any of the cost or benefit calculations below, please provide the modeled hourly output data for that PV system. If not, please provide any rationale for not using the NREL PVWatts model.

Utility System Costs

11. Please provide any studies or forecasts of system interconnection costs borne by the utility. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

12. Please provide any studies or cost forecasts regarding costs to integrate additional PV in the utility's service territory. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If applicable, please distinguish between pass-through costs (e.g. paid to an RTO) and costs internalized by the utility. If not available, please provide such data in the format that is closest to that requested.

13. Please provide any studies or forecasts of the expected additional annual utility administration costs (e.g., additional costs associated with billing, customer service, interconnection applications) associated with [insert applicable distributed PV policies under consideration, such as net metering, time-of-use pricing, etc.] If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

14. Please provide any studies or forecasts that describe and detail any other annual utility costs associated with customer-sited PV. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

Participant Costs

15. Please provide any studies or forecasts of the expected PV purchase and installation costs borne by the participant for a typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

16. Please provide any studies or forecasts of the expected operations and maintenance (O&M) costs borne by the participant for a typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

Public Costs

17. Please provide the expected local, regional, state, and federal tax credits associated with a typical residential PV system for each year of the study.

Benefit Information ("Avoided Costs")

Utility System Benefits

18. Please provide any studies or forecasts of the expected avoided energy costs per kWh associated with customer-sited PV, for each year of the study. These avoided energy costs should be determined using the expected hourly output of a typical residential PV system and the associated avoided energy costs <u>in that hour</u>. Please include fuel, variable O&M, SO_X and NO_X allowances, and any reagents or other materials with a volumetric cost. Please also identify the number of MWh used in assessing the avoided energy costs per kWh. In other words, does it represent the marginal avoided energy cost of a single MWh or an aggregation of many MWh? If the latter, how many?

19. Please provide any studies or forecasts of the expected avoided generation capacity costs per kW or per kWh associated with customer-sited PV.

20. Please provide the expected generation capacity credit associated with typical residential customer-sited PV, for each year of the study, and the calculation of each capacity credit.

21. Please provide any studies or forecasts of the expected avoided transmission capacity costs per kW or per kWh associated with customer-sited PV for each year of the study. If it is expected that there will be incremental additional transmission capacity costs (rather than avoided costs) for any of the given years, please provide that information as well.

22. Please provide any studies or forecasts of the expected avoided distribution capacity costs per kW or kWh associated with customer-sited PV, for each year of the study. If it is expected that there will be incremental additional distribution capacity costs (rather than avoided costs) for any of the given years, please provide that information as well.

23. Please provide any studies or forecasts of the expected avoided environmental capacity costs associated with customer-sited PV. Include any applicable avoided Renewable Portfolio Standard compliance costs, avoided carbon trading costs (e.g. RGGI or California's Cap-and-Trade program), avoided Clean Power Plan compliance costs, and avoided costs associated with fossil or nuclear generators not explicitly included in the avoided energy costs. If available, provide such cost estimates in terms of dollars per kW or kWh for each year of the study. If not available, please provide such data in the format that is closest to that requested.

24. Please provide any studies or forecasts that describe and detail any other avoided utility costs associated with the typical residential PV system (such as reduced arrearages), for each year of the study.

Benefits for Regions with Wholesale Markets

25. Please provide any studies or forecasts of the expected energy-related Demand Reduction Induced Price Effect (DRIPE) for the utility associated with the typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

26. Please provide any studies or forecasts of the expected generation capacity-related Demand Reduction Induced Price Effect (DRIPE) for the utility associated with the typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

Public Benefits

27. Please provide any studies or forecasts that describe and detail the expected other public benefits associated with customer-sited PV. If available, provide such estimates in terms of dollars per kW or kWh for each year of the study.

28. Please provide any studies or forecasts that describe and detail the expected environmental externality benefits (e.g. the societal value of carbon not otherwise internalized) associated with customer-sited PV. If available, provide such estimates in terms of dollars per kW or kWh for each year of the study.

APPENDIX B: MODELING ASSUMPTIONS

To undertake this study, Synapse developed a spreadsheet model that estimates payback periods and, when combined with avoided cost inputs, estimates the cost-effectiveness and cost-shifting associated with distributed solar. Below we describe the key assumptions and inputs used to produce the results shown in this report.

Study Period

The study period for modeling purposes was 2016 through 2050 in order to capture the full life of the solar PV installed during the first five years (assuming a system life of approximately 30 years).

Utility System Attributes

Total residential customers: We assumed a utility system with 1,000,000 residential customers. For simplicity, we assumed no growth of customers over the study period.

Initial solar PV customers: We assumed 10,000 PV customers for the first year (1 percent of residential customers).

Customer Load

A typical residential customer load profile for a city in the Southwest based on the Department of Energy's Building America House Simulation Protocols was used to model customer energy consumption prior to installation of a solar PV system. The load profile was downloaded from: http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states. The average daily summer and winter loads for the customer are depicted in Figure 31, below.

For simplicity, this load profile was then assumed to represent the average residential customer, as well as the average solar customer. However, we note that in many jurisdictions, solar customers may have a higher-than-average usage profile prior to installing the solar PV system.

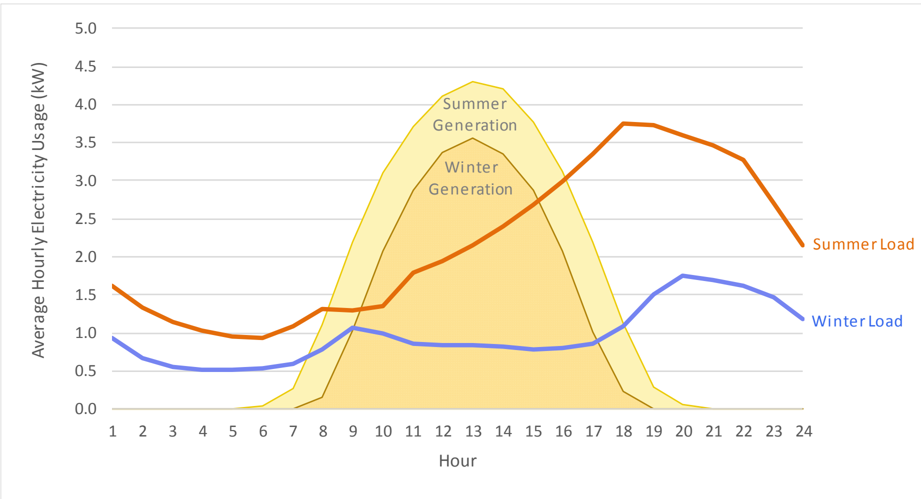
Solar PV System

System size: We assumed that the average residential customer installing solar would install a system sized to offset 88 percent of his or her load, which equates to an average system size of 6.53 kW_{DC}, with a DC to AC derating factor of 77 percent (based on the standard assumptions in NREL's PV Watts calculator http://rredc.nrel.gov/solar/calculators/pvwatts/system.html). The average summer and winter generation produced by the system are depicted in Figure 31.

Cost: We assumed an installed cost of $3.85 per watt for 2016, based on the continuation of cost trends reported by Lawrence Berkeley National Laboratory in *Tracking the Sun IX* (Barbose and Darghouth 2016). For additional installations for the years 2017–2020, we assumed that costs would continue to decline at the same average rate as observed over the period 1998–2015.

In addition, we assumed that the solar PV system would require maintenance over the system life. The annualized maintenance assumed was $21/watt, based on NREL's database of distributed generation technology operations and maintenance costs (available at http://www.nrel.gov/analysis/tech_cost_om_dg.html).

Figure 31. Average Customer Load and Generation Assumptions



Avoided Costs

As described elsewhere in the text, the net avoided utility system costs were assumed to be $0.113 per kilowatt-hour under the low utility avoided cost scenario, while the high net utility avoided cost was assumed to be $0.155 per kilowatt-hour.

Penetration

Maximum market size: To estimate the maximum potential market size, we used an estimate of 80 percent of residential customers, based on NREL's estimates of the percentage of small buildings that are suitable for rooftop solar (Gagnon et al. 2016). In some respects, this represents an optimistic value, as many of the occupants of these buildings are likely to be tenants, rather than owners. However, limiting the number of customers due to home ownership status may be overly conservative, as it does not account for community solar and other forms of virtual net metering.

Market penetration curves: For the purposes of this analysis, the most recent NREL adoption curves for residential customers were used to estimate the ultimate penetration of distributed solar (Sigrin et al. 2016). See Figure 6 in Section 3 for more information. However, instead of using the ultimate penetration value, we estimated an interim penetration level, i.e., what the penetration would likely be after five years, rather than in the long term.

We employed the Bass Diffusion Model (Bass 1969) to estimate the S-curve growth pattern and to develop an estimate of the five-year penetration level. To specify the S-curve, we assumed that the maximum would be reached in year 10. For modeling purposes, we followed the S-curve until year five, and then held the penetration level constant for the remainder of the study period. For example, the figure below shows the penetration levels assumed for the alternative compensation scenarios.

Figure 32. Example 5-Year Distributed Solar Growth Assumptions