BEFORE THE PUBLIC SERVICE COMMISSION
OF THE COMMONWEALTH OF KENTUCKY

Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit	Case No. 2020-00350

Direct Testimony of Benjamin D. Inskeep

On Behalf of Kentucky Solar Industries Association, Inc.

March 5, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. Benjamin D. Inskeep, 1155 Kildaire Farm Road, Ste. 202, Cary, North Carolina, 27511. My current position is Principal Energy Policy Analyst with EQ Research LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I earned a Bachelor of Science in Psychology from Indiana University in 2009 and a Master of Science in Environmental Science and a Master of Public Affairs from the O'Neill School of Public and Environmental Affairs at Indiana University in 2012.

I was employed at the North Carolina Clean Energy Technology Center at North Carolina State University from June 2014 through February 2016, where I co-created and served as lead author and editor of *The 50 States of Solar*, a quarterly report series tracking net metering policies and rate design changes impacting residential solar; worked on the *Database of State Incentives for Renewables and Efficiency (DSIRE)* project; and provided technical support, analysis, and workshops to state and local governments on reducing solar soft costs through the U.S. Department of Energy's SunShot Solar Outreach Partnership.

In my current position, I oversee EQ Research's general rate case subscription service, which includes reviewing and analyzing investor-owned electric utility rate case filings, providing summaries to clients, and maintaining a client-facing database of rate case information. I also contribute as a researcher and analyst to other policy service offerings such as a legislative and regulatory tracking services and perform customized research and analysis for clients. My *curriculum vitae* is attached as Exhibit BDI-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Kentucky Solar Industries Association, Inc. ("KYSEIA").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("PSC" OR "COMMISSION")?

A. Yes. I submitted Direct Testimony and Supplemental Testimony on behalf of KYSEIA in Case No. 2020-00174 addressing Kentucky Power Company's proposed changes to its net metering tariff in its general rate case.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING AND HOW IS IT ORGANIZED?

A. My testimony responds to Louisville Gas & Electric Company's ("LG&E" and "Company") net metering service 2 ("NMS-2") proposal. It is organized as follows:

- Section II addresses the provisions of the Net Metering Act and puts into context critical issues for the Commission's consideration in this proceeding.
- Section III goes into detail on the shortcomings of the Company's net metering proposal, as well as the future rate design changes the Company envisions making for net metering customers. It also discusses the importance of robust and clearly articulated Legacy Rights when making changes to net metering policies.
- Section IV provides national context for net metering policies, including how and under what conditions utilities and states have modified net metering policies and best practices when doing so.
- Section V contains my concluding remarks and summarizes my recommendations.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. I recommend that the Commission reject the Company's proposed Tariff NMS-2 because the Company failed to demonstrate that the proposal meets a basic requirement of the Net Metering Act specifying that the rates charged to net metering customers only recover the costs to serve those distributed generation ("DG") customers. The Company has not conducted sufficient customer load research and an accompanying cost of service study illustrating that current rates are not sufficient for this purpose, or that its Tariff NMS-2 would accomplish this objective. Accordingly, the Company has failed to meet its burden of proof and has not demonstrated that NMS-2 will result in rates that are fair, just, and reasonable. I therefore recommend Tariff NMS be retained unchanged.

To the extent the Commission determines changes are needed to the Company's Tariff NMS to comply with statutory changes enacted through the Net Metering Act, I recommend that the Commission only direct the Company to modify Tariff NMS to reflect the Net Metering Act's definitional change of net metering with respect to "dollar value" bill credits by specifying that the "dollar value" for electricity fed back to the grid by a net metering customer is the volumetric retail rate applicable to the net metering customer.

In the alternative, should the Commission determine that substantive changes to the Company's net metering tariff are necessary, it should still decline to adopt the Company's specific proposal because it contains serious flaws. I recommend the Commission ensure any changes to Tariff NMS reflect both the long-term costs and the benefits of net metering, adhere closely to the principle of gradualism, be informed by the modified net metering best practices established in other U.S. jurisdictions, and protect new net metering customers by adopting Legacy Rights protections for these customers. Specifically, I recommend a 25-year Legacy period with respect to rate design, compensation rate, and other tariff terms and conditions. I also recommend that the Commission allow net metering customers to expand the size of a Legacy net metering facility up to the customer's forecasted annual electricity usage or 45 kW, whichever is less, without forfeiting their Legacy Rights. Regardless of whether the Commission adopts this recommendation, I recommend that it allow customers to replace components of a net metering system, such as solar panels, without forfeiting Legacy Rights, even if it results in modest increases in the total system capacity.

II. THE NET METERING ACT CONTEXT

A. Net Metering Issues

Q. IN YOUR OPINION, WHAT ARE THE OVERARCHING ISSUES THE COMMISSION SHOULD EVALUATE WITH RESPECT TO NET METERING?

A. A criticism of retail rate net metering often made by utilities and reflected in the Company's underlying arguments in its testimony in this case is that it allows DG customers to be subsidized by non-DG customers. In other words, it is alleged that net metering customers do not pay their "fair share" of system costs (*i.e.*, their full cost of service), placing a greater burden on non-DG customers.

These arguments underlying proposals to modify existing net metering policies beg the questions of whether these criticisms are accurate, and if so, the magnitude of the problem and the best ways to mitigate it. If no subsidy can be identified either based on robust and compelling evidence, or due to a lack of the data and analysis needed to quantify such an impact, then modifications are likely unwarranted at this time. Likewise, if a subsidy is identified, but the magnitude is small or *de minimis*, then modifications could also be unwarranted. Conversely, if a subsidy is proven and significant in magnitude, then modifications could be warranted and a broad range of options should be considered to ensure the modifications that are approved are appropriate, commensurate with the issue being addressed, and based on sound ratemaking principles.

To the extent that a subsidy can be identified, there are two ways to mitigate it. One way to mitigate an identified subsidy is to simply reduce the compensation provided to customers as part of the net metering construct from the retail rate to some other amount. The other way is to provide rates to net metering customers that are more closely aligned with cost of service than would otherwise be the case. Both approaches have a potential role with respect to consideration of overall DG ratemaking policy, and there are often multiple ways through which the same objective can be achieved.

Therefore, the starting place is to determine whether a subsidy exists in the first place. For that purpose, there are two primary tools at the Commission's disposal: (a) cost-benefit analysis, and (b) cost of service analysis. As I discuss in more detail later in my testimony, cost-benefit analyses are generally conducted on a forward-looking basis with a goal of identifying the potential for a subsidy to exist in the long-term. A cost of service analysis takes a short-term outlook, using a snapshot of currently known costs to discover the amount of costs that net metering customers are responsible for relative to what they pay. Both approaches have merits. For instance, the long-term outlook used in a cost-benefit analysis is more consistent with long-term ratepayer indifference and utility planning. On the other hand, a cost of service evaluation, while effectively limited to the short-term, identifies responsibility for embedded costs, including whether net metering customers are themselves more or less costly to serve than the "average" customer in a class.

Q. WHAT FACTORS SHOULD THE COMMISSION CONSIDER AS PART OF ADOPTING REVISIONS TO DG CUSTOMER RATES.

A. Generally speaking, the Commission should consider the same generally accepted ratemaking principles (*i.e.*, the Bonbright principles) that govern the broader ratemaking process. In addition, in context of the Net Metering Act, there are also two considerations that require special attention:

1. Notwithstanding differences across utilities in Kentucky, the Commission should strive for resulting policies and general rate structures that are generally consistent across all utilities. Inconsistent policies would undermine basic fairness to all ratepayers and create unnecessary complexities for DG providers that work across multiple service territories.
2. The Commission should attempt to minimize "churn" in DG rates and policies that would be caused by establishing short-lived tariffs or programs that are subsequently replaced with different arrangements. Stated another way, a durable set of policies and rates is preferrable to frequent structural changes.

With respect to the second factor, the Commission should consider that utilities vary with respect to their level of net metering penetration relative to the 1% of peak load net metering cap. It makes little sense to develop a set of modified net metering tariffs only to have those same tariffs be replaced upon a utility reaching the net metering cap. Doing so could result in customer confusion in addition to being inefficient from the perspective of Commission and intervenor time and resources.

Q. WHEN YOU USE THE TERM "DURABLE" IN REFERENCE TO DG RATES AND POLICIES, ARE YOU SUGGESTING THAT SUCH POLICIES AND RATES BE PERMANENT?

A. No. The electricity industry landscape is changing in response to technological advancements and many other factors, and DG rates and policies should likewise be refined over time with these changes in mind. A "durable" regime need not be permanent, but it should provide customers and DG providers with a reasonable level of certainty, the ability to plan for potential future changes, and an orderly transition to any future policy framework. Stated another way, a durable policy framework avoids creating disruptive cliffs and works in advance of any defined inflection points (*e.g.*, the net metering cap) with an overarching objective of providing such a smooth transition.

B. Summary of Net Metering Act Provisions

Q. PLEASE SUMMARIZE THE KEY ELEMENTS OF THE NET METERING ACT THAT YOU VIEW AS THE MOST RELEVANT TO THE COMPANY'S NMS-2 TARIFF PROPOSAL.

A. In brief summary, the Net Metering Act, also referred to Senate Bill 100, allows net metering customers to be subjected to separate rates aligned with their cost of service, and replaces the rollover over kilowatt-hour credits for exports with a monetary credit system. More specifically, the Net Metering Act contains the following elements that are most directly relevant to the Commission's review of the Company's NMS-2 Tariff proposal:

1. It amends the definition of net metering to refer to the difference in the "dollar value" of electricity fed by a net metering customer to the grid (also referred to as "exports" and "excess generation" herein) and the "dollar value" of electricity consumed by the customer during a billing period.[1]
2. It requires the compensation for electricity fed to the grid by a net metering customer to take the form of a monetary credit (*i.e.*, a "dollar denominated bill credit").[2]
3. It entitles retail electric suppliers to implement rates for net metering customers that allow the retail electric supplier "to recover from its eligible customer generators all costs necessary to serve its eligible customer-generators, including but not limited to

[1] KRS 278.465(4).
[2] KRS 278.466(4).

fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators."[3]

4. It requires the Commission to establish the "dollar value" of electricity fed by a customer-generator to the grid over the course of a billing period.[4]

Q. WHAT DOES THE NET METERING ACT REQUIRE A UTILITY TO DEMONSTRATE AS PART OF A NET METERING RATES PROPOSAL UNDER THE NET METERING ACT?

A. There are two primary questions that need to be answered. First, the Net Metering Act requires that a utility demonstrate that the rates offered to net metering customers are consistent with its costs to serve those customers. Second, it requires that the rate for exports properly reflects the value of exports to the grid.

Q. WHAT DID THE COMMISSION DECIDE IN ITS JANUARY 13, 2021 ORDER IN CASE NO. 2020-00174 WITH RESPECT TO KENTUCKY POWER COMPANY'S PROPOSAL UNDER THE NET METERING ACT, TARIFF NMS II?

A. The Commission deferred its decision regarding net metering rates, stating that it was "not convinced by Kentucky Power's arguments that avoided cost should be the basis for establishing new net metering rates," and that Commission Staff would "work with its consultant to ensure that there is sufficient evidence to support the conclusion that Kentucky Power's proposed Tariff NMS II rates are fair, just and reasonable."[5] The Commission found that "Kentucky Power did not conduct a cost of service study or provide any cost support for serving net metered customers."[6]

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3 KRS 278.466(5).
4 KRS 278.466(3).
5 Order, January 13, 2021, Case No. 2020-00174, p. 85.
6 Order, pp. 84-85.

Q. WHAT DID THE COMMISSION DECIDE IN ITS FEBRUARY 22, 2021, ORDER ON THE COMPANY'S REHEARING REQUEST IN CASE NO. 2020-00174 WITH RESPECT TO THE COMPANY'S PROPOSED TARIFF NMS II?

A. The Commission denied Kentucky Power's request for rehearing on the issue of NMS II, affirming that Kentucky Power has the burden proof to establish sufficient evidence in support of its application, and finding that it failed to do so here. The Commission concluded that "there is no merit to in Kentucky Power's assertion that it provided sufficient evidence to carry its burden."[7]

Q. WHY ARE THE COMMISSION'S DECISIONS ON TARIFFS UNDER THE NET METERING ACT IN KENTUCKY POWER ("KENTUCKY POWER") COMPANY'S RATE CASE RELEVANT TO THIS PROCEEDING?

A. Although the proceeding is ongoing, the Commission's orders to date in Kentucky Power have thus far declined to approve Kentucky Power's significant modifications to its net metering tariff. The Commission's orders make clear that the utility bringing forth a proposal to modify an existing net metering tariff under the Net Metering Act carries the burden of proof to demonstrate that the proposal will result in fair, just and reasonable rates. A significant shortcoming of Kentucky Power Company's application that was identified by the Commission was its failure to provide a cost of service study or provide any cost support for serving net metered customers. As described in more detail below, these shortcomings are also features of the Company's proposal in the instant proceeding.

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[7] Order regarding rehearing, February 22, 2021, pp. 26-27 and Ordering Paragraph 17.

C. Cost of Service & Export Value

Q. HOW IS A UTILITY'S COST TO SERVE A SPECIFIC SET OF CUSTOMERS TYPICALLY DETERMINED?

A. In order to reliably identify the costs to serve a customer segment or class, a utility typically conducts load research and develops a cost of service study based on that load research for the customer segment in question.

Q. HOW DOES THIS RELATE TO THE PROVISIONS IN THE NET METERING ACT REFERRING TO A UTILITY'S ENTITLEMENT TO RECOVER ITS FIXED COSTS, INCLUDING DEMAND-RELATED COSTS?

A. A cost of service study determines responsibility for fixed and demand-related costs. A customer's cost of service is only the portion of those costs properly allocated to them based on their usage characteristics. A net metering customer can theoretically have a negative cost of service depending on the amount and timing of exports.

Q. WHY IS IT IMPORTANT THAT CONCLUSIONS ABOUT COST OF SERVICE FOR A CUSTOMER SEGMENT BE SUPPORTED BY A FULL COST OF SERVICE STUDY OF THAT SPECIFIC GROUP OF CUSTOMERS?

A. There are several reasons, but ultimately it amounts to a need for equity and fairness in ratemaking. It is unfair to use one standard of evidence, such as full cost of service study, for customers in general but permit a looser standard to be applied to certain customer segments. Likewise, the results of a shoddy or incomplete evaluation could result in unfair rates that charge customers in excess of their cost of service. Nothing in the Net Metering Act suggests that the Commission should depart from the typical standards it applies for the establishment of fair, just, and reasonable rates, or generally accepted ratemaking principles.

To put a finer point on the issue of fairness, without a targeted cost of service evaluation the Commission has no way of knowing at what level net metering customers pay for service relative to their cost of service, and how that might vary within the class. Not only does that lack of information raise the potential for customers to be overcharged, but it also prevents a more informed evaluation of the options necessary to remedy any issues that are present. In other words, the simple fact that a net metering customer purchases less electricity from a utility than they would have had they not installed a net metering system is insufficient evidence that they are being "subsidized" by other customers.

Q. CAN YOU CITE TO ANY SPECIFIC EXAMPLES ILLUSTRATING THIS POSSIBILITY?

A. Yes. In a 2015 general rate case, Oklahoma Gas and Electric ("OG&E") proposed to establish special demand rates for customers that install DG and eliminate any compensation for exported generation on the basis that the changes were necessary to eliminate an alleged "subsidy" to DG customers. As it turns out though, OG&E's class cost of service study, which evaluated residential DG customers as a separate class, showed that the residential DG class actually produced a considerably *higher* rate of return than the residential class as a whole (7.23% compared to 5.33%).[8] In other words, residential DG

[8] Oklahoma Corporation Commission, Docket No. PUD 201500273. Direct Testimony of Mark Garrett. March 31, 2016, p. 14, *available at*: http://imaging.occeweb.com/AP/CaseFiles/occ5272383.pdf

customers were subsidizing non-DG customers to a significant degree. Not surprisingly, the changes sought by OG&E were not adopted.[9]

Q. WHAT TYPE OF EVALUATION IS NECESSARY TO DETERMINE THE APPROPRIATE "DOLLAR VALUE" OF COMPENSATION FOR EXPORTS TO THE GRID?

A. The value of exports can only be identified with a cost-benefit study that utilizes a long-term time horizon and fully accounts for all future benefits and costs. Such an evaluation would typically be conducted under a total resource cost framework for the life of a typical DG system (*e.g.,* 25 years or longer). By default, under traditional net metering the dollar value of excess generation is simply the volumetric retail rate.

Q. WHY IS IT IMPORTANT TO EVALUATE COSTS AND BENEFITS UNDER A LONG-TERM TOTAL RESOURCE COST FRAMEWORK?

A. A long-term evaluation is necessary because DG systems produce value over the course of the system life. Limiting consideration of value to the short-term fails to consider what is in the best interest of all ratepayers over the time horizon during which a DG system will produce benefits. A total resource cost framework likewise aligns with the overall long-run interests of ratepayers. In other words, the value will influence customer decision-making on the construction of long-lived assets. Therefore, this value should reflect the long-term value. I provide an additional discussion of regulators' use of cost-benefit studies when considering questions of net metering policy and compensation, including successor tariff regimes, in Section IV.

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9 Oklahoma Corporation Commission, Docket No. PUD 201500273. Order No. 662059. March 20, 2017, *available at*: http://imaging.occeweb.com/AP/Orders/occ5360859.pdf

Q. HOW DO YOU VIEW COST OF SERVICE ANALYSES AND COST-BENEFIT ANALYSES FITTING TOGETHER WITH RESPECT TO DG POLICY AND COMPENSATION RATES?

A. Both have a valuable role to play. A cost-benefit analysis can answer the threshold question of whether compensation to customer-generators is lower or higher than the long-term value of that generation (*e.g.*, lower or higher than the retail rate under net metering). Where the long-term value is higher than the retail rate, there is no need to reduce the compensation rate; rather, it indicates that there could be justification to increase the compensation rate or maintain the existing level.

A cost of service evaluation offers a second test based on current conditions. Since a cost of service evaluation is effectively a snapshot in time, it fails to consider the long-term interests of ratepayers. However, it has the virtue of being able to identify an alternative cost benchmark (*i.e.*, an amount other than the retail rate) to which compensation could be compared, as well as the nuances of variations in cost of service that exist within the broader class and specific customer segments of a class. For instance, if net metering customers as a group, or subgroups of net metering customers (*e.g.*, those that install larger systems vs. smaller systems) have a lower cost of service than the "average" customer, the retail rate is an inappropriate basis for comparison. This could be true where net metering system production during peak times reduces the allocation of peak-driven costs to the broader class.

Both types of evaluations can yield valuable information on the nature of any short or long-term subsidization of different customer groups and the nature of solutions that may be used to mitigate any identified inequities.

Q. ARE COST-BENEFIT OR DG COST OF SERVICE STUDIES TYPICALLY REQUIRED AS PART OF REGULATORY REVIEWS OF NET METERING POLICIES AND DG TARIFFS?

A. They have not necessarily been universally required, but few jurisdictions have adopted major changes to net metering or established net metering successor tariffs without requiring one or both. Typically, benefit-cost analyses have been performed by consultants with subject matter expertise at the request of legislators or regulators. A cost of service analysis is more commonly used in ratemaking proceedings where specific revisions to DG customer purchase or compensation rates are being proposed, such as the case in the instant proceeding.

III. LG&E's NET METERING PROPOSAL

A. Net Metering Tariffs

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S NMS-2 TARIFF PROPOSAL.

A. The Company is proposing to end retail rate net metering and replace it with what I refer to as a net billing arrangement in which *all* electricity generated by an eligible customer-generator that is fed back to the electric grid would be compensated at the Company's avoided cost rate under the non-time differentiated rate in the Company's Standard Rate Rider SQF ("Tariff SQF"), which is currently set at $0.02173/kWh. The Company would create a new net metering rate schedule, Rider NMS-2 ("Tariff NMS-2"), and rename its existing Rider NMS to be Rider NMS-1. I refer to these as "Tariff NMS" and "Tariff NMS-1" and use the two terms interchangeably in my testimony to refer to the Company's existing net metering tariff. Tariff NMS-1 will serve net metering customers that have submitted an application for net metering service before the effective date of rates established in this proceeding ("existing net metering customers"), and Tariff NMS-2 will apply to all other net metering customers ("new net metering customers").[10]

Q. WHAT DO YOU MEAN BY "NET BILLING"?

A. As commonly used, net billing is when a utility compensates an eligible DG customer for electricity generated by the customer that is fed back to the electric grid using a rate other than the retail rate for consumption, after netting production and consumption over intervals shorter than the billing period (e.g., instantaneous, 15-minute or 1-hour intervals).[11] As under net metering, a net billing customer is still able to self-consume

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[10] Direct Testimony of Robert Conroy, p. 23.

[11] *See, e.g.*, Tom Stanton, "Review of State Net Energy Metering and Successor Rate Designs," National Regulatory Research Institute (2019), p. 11.

electricity generated by the DG system. However, in contrast to net metering, a net billing arrangement credits a customer for net exports that occur during intervals shorter than the billing period (or for all gross exports if an instantaneous measurement is used) at a rate that is below the applicable retail rate. Some states (*e.g.*, Michigan and Iowa) have adopted the term "inflow/outflow billing," to refer to the policy that I describe as net billing.

Q. HOW IS THE COMPANY'S PROPOSED TARIFF NMS-2 DIFFERENT FROM THE COMPANY'S TARIFF SQF?

A. While there are some differences in between the two tariffs, they would appear to have nearly identical impacts for a DG customer that is eligible to take service under either tariff and who consumes a portion of the electricity generated by the DG system on-site and exports the remaining portion of the electricity generated by the DG system to the grid. In response to information requests, the Company confirmed that a person "who elects to take service under either Rider SQF or Rider NMS-2 will be billed the standard rate schedule for the energy consumed and will receive compensation for the energy put back on the grid at the Rider SQF rate as specified in the appropriate section of the tariff."[12] The main differences between Tariffs NMS-2 and SQF appear to be the size of systems eligible to participate (up to 45 kW under NMS-2 compared to up to 100 kW under SQF), compensation taking the form of a payment under SQF rather than a monetary bill credit under NMS-2, an additional time-differentiated rate option ("Rate A") being available under SQF, and unused bill credits expiring for net metering customers.[13]

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[12] Response to Kentucky Solar Industries Association, Inc.'s Supplemental Requests for Information, Dated February 5, 2021, A-6.

[13] Response to Kentucky Solar Industries Association, Inc.'s Supplemental Requests for Information, Dated February 5, 2021, A-6.

Q. WHAT IS THE SIGNIFICANCE OF THE SIMILARITY BETWEEN TARIFF NMS-2 AND TARIFF SQF?

A. In essence, the Company's proposed Tariff NMS-2 appears to be little more than an unfavorable version of the Company's existing Tariff SQF, as the compensation rate for electricity exported to the grid is the same but Tariff NMS-2 customers would have unused bill credits expire rather than being paid out as under Tariff SQF. It is unclear why net metering would need to be subject to various additional statutory restrictions (e.g., 45 kW system size limitation, 1% participation cap) if a utility can implement net metering's key provisions in a manner that is functionally similar, if not effectively identical in practice, to existing avoided cost tariffs that are not subject to such restrictions. Indeed, it is unclear why a separate net metering policy would be needed at all if it is permitted to be transmogrified into an inferior avoided cost rate tariff. Had the legislature intended the Company to effectively replace net metering with its existing avoided cost tariff in place for Small Power Production facilities, it could have just eliminated net metering altogether rather than amending but keeping in place the net metering statute and delegating the compensation rate issue to the Commission to determine using standard ratemaking principles.

Q. DID THE COMPANY CONDUCT A COST OF SERVICE EVALUATION OF NET METERING CUSTOMERS TO IDENTIFY THE AMOUNT OF FIXED COSTS THAT THEY ARE ACTUALLY RESPONSIBLE FOR?

A. No. In response to information requests for the Company to "Identify the cost to serve a distributed generation customer," the Company responded by pointing to Exhibit WSS-2.[14]

[14] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-8.

However, WSS-2 contains no information identifying the cost to serve a DG customer in the Company's service territory. Instead, it contains the Company's cost components for residential service. Based on the Company's response, as well as the information contained in its application and direct testimony, I conclude the Company has not conducted a cost of service evaluation of either residential or non-residential net metering customers.

Additional responses to information requests make clear that the Company also failed to conduct the load research that would be necessary to establish representative load profiles of its net metering customers. The Companies stated that they "have interval data for only approximately 100 net metering customers and have assumed that more data would be needed to provide a representative sample given the diversity in consumption and distributed generation facilities for net metering customers overall."[15] The Company also admitted that the load data it does have that it used to develop estimates of the alleged subsidy as a result of net metering customers not being subjected to four-part rates is "not based on a statistically valid sample."[16] Needless to say, statistically valid data are necessary to arrive at conclusions regarding the Company's costs to serve residential DG customers, and the Commission should discard the Company's assertions and rhetoric that that are not based on valid data.

Q. IS THE COMPANY'S AVOIDED COST RATE UNDER TARIFF SQF AN APPROPRIATE COMPENSATION RATE FOR ALL ELECTRICITY A NET METERING CUSTOMER FEEDS BACK INTO THE GRID?

[15] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-10.

[16] Response to Commission Staff's Second Request for Information, Dated January 8, 2021, A-122.

A. No. For several reasons, avoided cost rates developed to compensate qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 are an inappropriate basis for determining the compensation rate for exports under net metering programs. First, the Company's avoided cost rate methodology contains numerous shortcomings, as described in more detail in the Direct Testimony of KYSEIA Witness Justin Barnes, which results in a compensation rate that is below the Company's true avoided costs.

Second, the avoided cost rate fails to account for all of the benefits provided by net metering systems over the life of a net metering system, meaning the avoided cost rate undercompensates net metering customers. For instance, DG systems sited at the point of load do not use the transmission and distribution infrastructure to the same extent as QFs or centralized generation facilities and have fewer associated line losses. For this reason, many jurisdictions have conducted a long-term cost-benefit analysis that provides a more accurate accounting of all of the types of benefit and cost categories, as I describe more in Section IV. A valuable reference on this topic is the National Energy Screening Project's *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, which was developed to help guide jurisdictions in developing and conducting benefit-cost analyses of distributed energy resources.[17]

Finally, as previously noted, the Company has not supported its proposal with the information necessary to determine if a change to net metering compensation rates is necessary in the first place, and whether its proposed changes would result in rates that recover the costs necessary to serve net metering customers. For example, the Company

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[17] Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

failed to conduct sufficient load research and perform a cost of service evaluation of residential and commercial net metering customers.

I will also note that moving from a retail rate to avoided cost rate compensation would be a severe reduction in the compensation rate. Relative to the Company's proposed residential volumetric retail rate, Tariff SQF represents an approximate 79% reduction in the compensation rate. Such an extreme change does not comport with the ratemaking principle of gradualism.

Q. HOW WOULD THE COMPANY'S NMS-2 TARIFF AFFECT RESIDENTIAL CUSTOMER BILL SAVINGS RELATIVE TO THE CURRENT NET METERING TARIFF?

A. I estimate that it would reduce customer bill savings by roughly 45% for a solar net metering system sized to produce an approximate 100% load offset on an annual basis (*i.e.*, 8 kW-ac). I arrived at this estimate by developing a solar production profile for a system installed in Louisville with basic default assumptions using the National Renewable Energy Lab ("NREL") PVWatts Calculator. I then applied this hourly production profile to a typical residential load profile that I developed based on the residential class load profile provided by the Company.[18] Using *hourly* production and load figures as opposed to more granular data means that this analysis will slightly understate the actual amount of exported electricity, since the Company will be measuring this on an instantaneous basis (*i.e.*, my analysis is akin to using an *hourly* netting interval instead of the *instantaneous* netting interval proposed). Therefore, the reduction in customer bill savings produced by this

[18] Response to Joint Initial Data Requests of the Attorney General and KIUC Dated January 8, 2021, A-173.

method is a conservative estimate, and the actual reduction to bill savings will be slightly larger.

Of course, there is likely to be a fair amount of variation between individual customers with respect to their hourly load profiles. Customers with lower daytime loads would produce a greater quantity of exports than those with higher daytime loads and consequently forfeit more value due to excess daytime generation being compensated at the lower rate proposed by the Company instead of the volumetric retail rate credits under Tariff NMS. Second, system orientation and other site characteristics would influence the solar production shape and correspondingly, the amount of hourly exports. However, I believe my estimate is reasonable for a typical residential customer taking service from the Company and provides a useful illustration of the financial impacts of the Company's proposal on a customer installing a solar DG system.

Q. WHAT WOULD BE THE IMPACT OF TARIFF NMS-2 ON THE ADOPTION RATE OF SOLAR NET METERING IN THE COMPANY'S SERVICE TERRITORY?

A. The Company admitted that Tariff NMS-2 would have a devastating impact to the adoption rate of solar net metering. Under the current growth rate for net metering, the Company calculates it would hit its net metering cap within six years.[19] However, if Tariff NMS-2 is adopted, the impact would be so dire that LG&E forecasts it would not even reach *one-half* of its 1% cap over the *next 29 years*, with installed net metering capacity increasing from 5.88 MW in 2020 to only 11.26 MW in 2050.[20] Accordingly, I find the Company's claims

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19 Response to Commission Staff's Second Request for Information, Dated January 8, 2021, A-122.

20 Response to Metropolitan Housing Coalition, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society's First Set of Data Requests, Dated January 8, 2021, A-2.

that its net metering proposal comports with the ratemaking principle of continuity and gradualism[21] to be dubious, at best.

B. Net Metering Service Interconnection Guidelines

Q. IS THE COMPANY PROPOSING CHANGES TO ITS NET METERING SERVICE INTERCONNECTION GUIDELINES IN THIS PROCEEDING?

A. Yes. The Company is proposing a number of changes to the Net Metering Service Interconnection Guidelines, including changes to applicable industry standards and eliminating net metering service application forms from its tariff.

Q. HAS THE COMMISSION OPENED A SEPARATE PROCEEDING TO CONSIDER CHANGES TO NET METERING SERVICE INTERCONNECTION GUIDELINES?

A. Yes. Case No. 2020-00302 was opened in September 2020 to investigate net metering interconnection guidelines.

Q. WHAT ACTION DO YOU RECOMMEND THE COMMISSION TAKE IN RESPONSE TO THE COMPANY'S PROPOSED CHANGES TO ITS NET METERING SERVICE INTERCONNECTION GUIDELINES?

A. I recommend the Commission consider substantive changes to the Company's Net Metering Service Interconnection Guidelines in Case No. 2020-00302 rather than in this proceeding. Case No. 2020-00302 is a better forum for considering the very technical and specific issues presented by revisions to interconnection guidelines rather than a rate case that involves a broad set of numerous other complex issues. Furthermore, that proceeding will allow for any changes the Commission deems are warranted to net metering

[21] Direct Testimony of William Steven Seelye, p. 47.

interconnection guidelines to be standardized and aligned across multiple Kentucky utilities, which is a more efficient use of Commission and intervenor time and resources.

C. Insufficiency of the Company's Application

Q. WHAT IS YOUR GENERAL ASSESSMENT OF THE COMPANY'S NMS-2 TARIFF PROPOSAL?

A. The Company has failed to meet its burden of proof and has not demonstrated that Tariff NMS-2 will result in a rate that is fair, just, and reasonable. The Company both failed to conduct adequate load research on its net metering customers and evaluate the cost to serve net metering customers. Therefore, it has failed to adequately demonstrate that net metering customers are not currently paying their full cost of service. As I previously observed, the simple fact that a customer-generator purchases less electricity from a utility than they would have otherwise without a net metering system is insufficient evidence that they are being "subsidized" by other customers, and insufficient evidence that they would not pay the fixed and demand-related costs for which they are responsible. Likewise, a basic comparison of the effective retail rate compensation under net metering to the avoided cost rate under Tariff SQF is also insufficient evidence that net metering customers are being "subsidized" by other customers, as such an analysis does not consider whether net metering customers are under- or over-paying their cost of service. For instance, for the sake of argument, even if a net metering customer was being "overcompensated" for exported electricity under retail rate net metering, at the same time they could also be "overpaying" the utility for their electric service under existing applicable retail service rates, based on the utility's actual cost to serve the net metering customer, resulting in no net impact to non-net metering customers. For this reason, the Company's proposal to separately address the compensation rate from the issues of cost of service and rate design is fundamentally flawed.

Tariff NMS-2 also suffers from flaws in the methodology the Company uses to establish the avoided cost rate, which is discussed in more detail in the Direct Testimony of KYSEIA Witness Justin Barnes.

Q. PLEASE EXPLAIN HOW THAT RELATES TO THE REQUIREMENTS OF THE NET METERING ACT.

A. The Net Metering Act only entitles a utility to recover the "*costs necessary to serve* its eligible customer-generators" (emphasis added).[22] It certainly does not entitle the Company to recover more than those costs. The only way to arrive at reliable conclusions about whether a given tariff design would accomplish aligning net metering rates with cost causation, including compensation for exports, is to conduct a complete cost of service evaluation. Stated another way, in order to remedy any subsidy that exists from one group of customers to another, one must first quantify the subsidy using well-vetted and accepted methods for doing so.

Q. HAS THE COMPANY PRESENTED ANY EVIDENCE THAT SPEAKS TO QUANTIFYING A SUBSIDY THAT NET METERING CUSTOMERS RECEIVE FROM NON-DG CUSTOMERS?

A. The Company's analysis alleges there are two subsidies being provided to net metering customers: (1) subsidies from "overcompensating" net metering customers by providing a credit for excess generation at the retail rate instead of the avoided cost rate; and (2) subsidies from using a two-part rate, which the Company alleges does not collect the cost

[22] KRS 278.466(5).

to serve the net metering customer. In this proceeding, the Company only proposes to address the first of the two alleged subsides. Its analysis concludes that a residential net metering customer receives a subsidy amounting to $0.08309 per kWh under its first subsidy category.[23] The Company alleges that this results in a total subsidy of $148,668 for residential net metering customers and $31,753 for non-residential net metering customers.[24] These amounts are derived by multiplying the difference between the retail rate and the avoided cost rate by the kWh supplied to the grid by net metering customers. The problems with this simplistic analysis are that: (1) it fails to properly account for net metering customer cost of service before the installation of the net metering system, and (2) it fails to properly account for the contribution that a net metering system makes in altering a customer's cost of service.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW A COST OF SERVICE-BASED EVALUATION WOULD PRODUCE A DIFFERENT RESULT?

A. Yes. A simple example is for energy costs. The Company's cost of service study produces a residential class revenue requirement for energy-related costs of $131,381,848.[25] Total residential class energy sales are approximately 4.049 billion kWh, leading to a volumetric energy rate of $0.03245 per kWh. A customer with a net metering system offsets energy-related costs on a 1:1 basis, meaning that any amounts they do not pay due to on-site generation are fully offset by a reduction in costs to the residential class. In other words, it is not possible for any "subsidy" to exist with respect to energy-related costs. Yet, the

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23 Response to Commission Staff's Second Request for Information Dated January 8, 2021, A-122.
24 Response to Commission Staff's Second Request for Information Dated January 8, 2021, A-122.
25 Exhibit WSS-2.

Company's subsidy analysis would give a DG customer credit for reducing energy-related costs at only $0.02173 per kWh (*i.e.*, the Tariff SQF rate).

This disconnect is present throughout the Company's evaluation of the supposed subsidy, as the Company's analysis fails to account for net metering contributions to reducing the allocation of most system costs to a customer's respective class (*e.g.*, transmission and primary distribution are allocated based on maximum class non-coincident peak demand[26]). Where net metering reduces the class contribution to peaks, or if DG customers already contribute less to peaks even before installing a net metering system, the broader class benefits from their presence in the form of reduced allocations of those costs.

Q. WHAT DO YOU CONCLUDE ABOUT THE SUFFICIENCY OF THE COMPANY'S APPLICATION WITH RESPECT TO THE NET METERING ACT AND THE EXISTENCE OF A SUBSIDY TO DG CUSTOMERS?

A. The Company has failed to present evidence sufficient to determine the costs to serve net metering customers, whether they already pay amounts consistent with their costs of service, and ultimately, the nature and magnitude of any subsidy that does exist between DG customers and non-DG customers.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION GIVEN THIS LACK OF EVIDENCE?

A. The Company's Tariff NMS-2 proposal should be rejected because the Company has failed to meet a basic requirement of the Net Metering Act that the rates applied to net metering customers be based on their cost of service.

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[26] Exhibit WSS-31.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE SPECIFIC LANGUAGE USED IN THE COMPANY'S NMS-2 TARIFF?

A. Yes. The wording of the tariff does not align with the Company's stated interpretation of the tariff. Specifically, Tariff NMS-2 provides that "For each billing period, Company will (a) bill Customer for all energy consumed in accordance with Customer's standard rate and (b) Company will provide a dollar denominated bill credit *for each kWh of production*. The dollar denominated bill credit will be calculated by multiplying the *total kWh of production* within the billing period by the Non-Time-Differentiated SQF rate within tariff Sheet No. 55."[27] The emphasized tariff language suggests that Tariff NMS-2 could be construed as a buy-all sell-arrangement where *gross* production from a net metering system is credited at the avoided cost rate instead of the *net* production. To align with the Company's interpretation of Tariff NMS-2, the language would need to be modified to reflect that the Company is only referring to production that is exported to the grid, and not all kWh production, which would include production used on-site behind the meter at the time it is generated.

D. Rate Design Issues

Q. WHAT RATE DESIGN CHANGES DOES THE COMPANY ENVISION PROPOSING FOR NET METERING CUSTOMERS IN THE FUTURE?

A. The Company is not proposing cost-based rates or a separate rate design for net metering customers in this case, but it makes clear it intends to do so in the future.[28] Specifically, the Company indicates that it is envisioning proposing three- or four-part rates on net metering customers in the future, such that net metering customers would be subjected to a fixed

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27 Tariff NMS-2. (Emphasis added.)

28 Direct Testimony of William Seelye, p. 46-64.

charge, energy charge, peak demand charge, and base demand charge.[29] The Company asserts that "serving distributed generation customers under a two-part rate consisting of only a customer charge and energy charge forces non-distributed generation customers to subsidize distributed generation customers."[30]

Q. DO YOU AGREE WITH THE COMPANY'S ASSESSMENT THAT DEMAND CHARGES ON RESIDENTIAL NET METERING CUSTOMERS ARE NECESSARY FOR THE COMPANY TO RECOVER THE COST TO SERVE THESE CUSTOMERS?

A. No. The Company has neither demonstrated an under-recovery of its demand-related costs, nor sufficiently justified its rate design solution for this alleged problem.

First, at a fundamental level and described above in more detail, the Company has not demonstrated that net metering customers are not currently paying their cost of service through existing rates. In other words, the Company has not shown there are any "missing" demand-related costs that it is failing to recover from net metering customers, as it has not performed the cost of service analysis that would be necessary to do so.

Second, it is important to distinguish that cost *classifications* (energy-related costs, demand-related costs, and customer-related costs), while potentially informative, do not always perfectly match onto the ultimate *rate design* employed to recover those respective costs. For example, utilities usually recover *demand-related* costs through *energy charges* for residential and small commercial customer classes rather than through demand charges. In fact, nearly every investor-owned utility in the nation uses this type of two-part rate with a fixed customer charge and one or more volumetric energy (per kWh) charge as the default

[29] Direct Testimony of William Seelye, p. 47.
[30] Direct Testimony of William Seelye, p. 50.

rate for residential customers. In addition, many other types of businesses (*e.g.*, restaurants, retail stores) have both "fixed" and "variable" costs from a short-term business perspective, yet they only charge customers a variable charge for products. Therefore, the Company's assertion that demand charges are necessary to recover its cost to serve DG customers has no merit.

Q. PLEASE EXPLAIN IN GENERAL WHY DEMAND RATES ARE INCONSISTENT WITH THE PRINCIPLE OF COST CAUSATION.

A. Infrastructure costs are caused by the *aggregate* customer contributions to peak demands on different parts and levels of the system. A customer's maximum monthly demand only approximates their contribution to those costs for facilities in close proximity to the customer, such as line transformers. Even line transformers may experience peaks that depart from individual customer peaks if they serve multiple customers because the peak demands of individual customers do not necessarily occur during the same window during a month. The greater the number of customers served by a given piece of infrastructure, the greater this diversity benefit becomes.

Non-coincident demand charges fail to account for this diversity and fail to account for the time-varying nature of costs. The departure from cost causation is particularly pronounced at the generation and transmission level where a large amount of load diversity is present. Non-coincident demand charges are effective at capturing cost causation only for customers that have high load factors or peak demands that coincide with times of peak demand. They overcharge customers with lower load factors and those that have peaks during off-peak times.

Q. IS THIS VIEW OF DEMAND CHARGES SHARED BY OTHERS?

A. Yes. The Regulatory Assistance Project ("RAP") recently published a Policy Brief ("RAP Policy Brief"), which I have attached to my testimony as Exhibit BDI-2, discussing the rationale for demand charges. The RAP Policy Brief concludes that demand charges have little or no place in modern rate design. The RAP Policy Brief argues that:

> Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60- minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general. For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU [time-of-use] rates and critical peak pricing, are more efficient than peak window demand charges.[31]

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[31] Mark LaBel and Frederick Weston. Regulatory Assistance Project. "Demand Charges: What Are They Good For? An Examination of Cost Causation, November 2020, p. 7. *Available at*: https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf.

Q. WHY DO THE AUTHORS OF THE RAP POLICY BRIEF REACH THIS CONCLUSION?

A. The authors observe that what matters for cost causation is not a customer's individual peak, but their contribution to the system peak, and that time-varying energy rates are more economically efficient than on-peak window demand charges. They further observe that a significant portion of capacity investment is properly classified as energy-related rather than demand-related because "Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework."[32]

Q. ARE THERE OTHER PROBLEMS WITH IMPOSING DEMAND CHARGES ON RESIDENTIAL NET METERING CUSTOMERS?

A. Yes. There are a number of significant additional drawbacks to assessing demand charges on residential or other small customers.[33] These customers are generally not accustomed to demand charges. The basic rate design most residential customers experience has likely not meaningfully changed in their lifetimes. In the very least, a major rate design change of this nature would take considerable customer education simply to make the customer aware of the new charge and how it impacts their bill. Even for residential customers that are made aware of and fully grasp the concept of demand charges may not be able to adopt the additional technologies and/or behavioral changes necessary at the household level to moderate their monthly assessed demand charge. Therefore, there is a large potential that

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32 *Ibid.*, p. 21.

33 *See, generally,* "Chernick, P., Colgan, J., Gilliam, R., Jester, D., & LeBel, M. (2016). "Charge without a cause? Assessing electric utility demand charges on small consumers." (Electricity rate design review paper No. 1). Available at: https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf.

such a significant change could have adverse outcomes, and that those adverse outcomes are more likely to occur and be more pronounced for members of vulnerable communities.

Q. WHY THEN ARE DEMAND CHARGES A COMMON FEATURE IN UTILITY RATES FOR NON-RESIDENTIAL CUSTOMERS?

A. The prevalence is attributable to several factors, such as metering capabilities and relative costs, and due to the fact that larger industrial customers most often subjected to demand charges tend to have higher load factors and relatively limited ability to shift loads, resulting in their demand during peak times being similar to their demand at other times. The authors of the RAP Policy Brief include a discussion of this history, noting numerous examples of prominent industry writers discussing the limitations and downsides of demand charges even in the more historic context.[34] For instance, they note that Dr. James Bonbright found little sense in "the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof."[35]

Q. DO YOU HAVE CONCERNS REGARDING THE EVIDENCE THE COMPANY PROVIDED TO SUPPORT ITS ARGUMENT THAT DEMAND CHARGES ARE REASONABLE?

A. Yes. The Company claims that "Over the past decade, a small but growing number of utilities have implemented demand rates for all their residential customers, not just new distributed generation customers as in Kansas."[36] However, when asked for support of its

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34 RAP Policy Brief, pp. 8-11.
35 RAP Policy Brief, p. 10, quoting Bonbright, 1961, p. 316.
36 Direct Testimony of William Seelye, p. 53.

statement through an information request, the Company was not able to provide a single example of a peer U.S. investor-owned utility that has implemented a mandatory demand charge on all of residential customers.[37] The fact that apparently not a single utility regulator in the country has been willing to approve such a mandatory three-part rate design for residential customers of an investor-owned utility is telling.

The Company goes on to highlight the Kansas Corporation Commission's ("KCC") Order in Docket No. 15-WSSE-115- RTS, in which the KCC approved a residential rate schedule for Westar Energy Company (now called "Evergy Kansas Central, Inc." and referred to hereafter as "Evergy") that required residential customers adding behind-the-meter electric generation after a specified date to take service under a three-part rate schedule. The impression left from reading the Company's testimony was that the three-part rate was not only permissible, but would remain in effect going forward for new net metering customers and represented a clear example for the Commission to emulate in Kentucky. However, what the Company failed to note in its testimony is that more than *seven months prior* to the Company filing its rate case application and testimony, the Kansas Supreme Court issued an Opinion striking down the mandatory three-part rate on DG customers, finding that the "rate design is unlawful and the Commission erred by approving a discriminatory rate."[38]

On remand, the KCC considered two proposals by Evergy to replace the unlawful, discriminatory three-part rate: (1) a $3.00 per kW of installed DG capacity "grid access charge," and (2) in the alternative, a $35 minimum bill applied to most residential

[37] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-9.

[38] In the Matter of Joint Application of Westar Energy and Kansas Gas and Electric Co., 311 Kan. 320, 460 P.3d 821 (2020).

customers. On February 25, 2021, the KCC issued an Order rejecting both of Evergy's proposals.[39] As a result, DG customers in Evergy's Kansas service territory will now have the identical two-part rate structure as non-DG customers and will not be assessed a grid access charge or higher minimum bill.

Q. WHAT WOULD BE THE IMPACT TO DG CUSTOMERS OF THE COMPANY IMPLEMENTING TARIFF NMS-2 THROUGH THIS PROCEEDING FOLLOWED BY A MAJOR CHANGE IN NMS-2 RATE DESIGN IN A SUBSEQUENT PROCEEDING?

A. As described above, Tariff NMS-2 alone would have substantial negative impacts on the adoption rate of solar net metering as a result of the reduced financial value to DG customers due to the large reduction to the compensation rate. Layering on future rate design changes could further erode the financial value of the net metering system to the customer, resulting in a catastrophic negative impact to a prospective investment in a solar net metering system. Of course, the exact impact is unknown at this time, as the Company has not put forth its specific rate design proposal in this case. But the substantial decrease in the financial value of a net metering system under the Company's proposal in this rate case to move from the effective volumetric retail rate to the avoided cost rate, combined with the uncertainty over future negative changes related to rate design, would certainly have a market-chilling and broadly negative impact to DG customers.

<u>E. Legacy Rights</u>

Q. PLEASE EXPLAIN THE PRINCIPLE OF NET METERING LEGACY RIGHTS AS IT RELATES TO THE CURRENT PROCEEDING.

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[39] https://estar.kcc.ks.gov/estar/ViewFile.aspx/20210225103241.pdf?Id=dbf0d78a-209e-4c08-82a9-8a58810d3cef

A. Net metering Legacy Rights refers to a decision made by a state utility regulator or established through legislation that allow DG customers to continue to take service under a net metering tariff in the event it is discontinued for new participants. In the present context, it refers to allowing net metering customers to continue to take service under their electric utility's existing net metering tariff for either a defined period of time, or in perpetuity, should net metering be modified or discontinued. It also refers to allowing those same customers to continue taking service under a current rate structure should changes be made to rate structures that apply to DG customers. The intent of net metering Legacy Rights is to respect the long-term investments made by customers in DG systems that were made prior to the time when changes were known.

In this testimony, the term Legacy Rights is used instead of "grandfathering," given the historically negative connotations of the latter term.[40]

Q. PLEASE ELABORATE ON WHAT EXPECTATIONS A CUSTOMER WOULD TYPICALLY HAVE WHEN CONSIDERING WHETHER TO INSTALL A DG SYSTEM.

A. It is reasonable to assume that a customer considering installing a DG system would, among other considerations, weigh the potential financial benefits of such an investment over its anticipated lifetime against the upfront costs of installing the system. DG systems typically involve a substantial upfront cost, with financial benefits then accruing over the life of the system in the form of offsetting electricity purchases from the utility.

[40] *See, e.g.*, Request for Rehearing and Request for Clarification of PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. EL-16-49 and Consolidated Docket Nos. ER18-1314 and EL18-178, January 21, 2020, Footnote 21 (noting that "Because the term 'grandfathering' carries historically negative connotations, PJM encourages the use of an alternative term…").

It is also reasonable to assume that a potential net metering customer, like most utility customers, should anticipate changes to certain rate components over time. Customers are accustomed to and generally accept that periodic and typically gradual rate changes will occur. That is, customers have an expectation based on decades of ratemaking that they are likely to experience relatively small rate changes from year to year (*i.e.*, typically increases in existing rate components) rather than dramatic changes in rates or rate structure. This expectation is in large part attributable to the fact that utility regulators have historically made substantial efforts to avoid "rate shock" in ratemaking decisions, consistent with the principle of gradualism.

Q. HAVE OTHER STATE UTILITY REGULATORS ADDRESSED LEGACY RIGHTS FOR EXISTING NET METERING CUSTOMERS?

A. Yes, within the spectrum of recent regulatory decisions affecting net metering and DG customer rates, Legacy Rights is among the most consistently addressed elements. I have developed a table (Exhibit BDI-3) that provides an overview of how other state regulatory commissions have addressed Legacy Rights for existing DG customers in their consideration of changes to net metering and/or rate structures for DG customers. As Exhibit BDI-3 shows, while there are some differences in how states have approached Legacy Rights, there are common conclusions as well. The primary conclusions I draw from reviewing other state policies with respect to net metering Legacy Rights are that:

1. While certain elements vary from state to state, as a general policy principle, it enjoys universal support from regulators.
2. The most common Legacy period duration is at least 20 years, ranging upward to indefinite in some states.

3. Legacy Rights eligibility is based on a customer submitting an application either before some future benchmark or date certain, or the date of a decision.

4. Legacy Rights under a modified net metering policy or net metering successor policy tend to mirror the Legacy Rights period under the original net metering policy, or have slightly shorter time periods, although some states have not yet addressed this.

Q. WHAT LEGACY RIGHTS PROVISIONS WERE INCLUDED IN THE NET METERING ACT THAT APPLY TO NMS-1 CUSTOMERS?

A. The Net Metering Act, codified at KRS 278.466(6), provides:[41]

> For an eligible electric generating facility in service prior to the effective date of the initial net metering order by the commission in accordance with subsection (3) of this section, the net metering tariff provisions in place when the eligible customer-generator began taking net metering service, including the one-to-one (1:1) kilowatt-hour denominated energy credit provided for electricity fed into the grid, <u>shall remain in effect at those premises for a twenty-five (25) year period</u>, regardless of whether the premises are sold or conveyed during that twenty-five (25) year period. For any eligible customer-generator to whom this paragraph applies, each net metering contract or tariff under which the customer takes service shall be identical, with respect to energy rates, rate structure, and monthly charges, to the contract or tariff to which the same customer would be assigned if the customer were not an eligible customer-generator. (Emphasis added.)

[41] KRS 278.466(6).

Q. WHAT LEGACY RIGHTS PROVISIONS WERE INCLUDED IN THE NET METERING ACT THAT WOULD APPLY TO NMS-2 CUSTOMERS, IF APPROVED?

A. The Net Metering Act does not directly address Legacy Rights for customers taking service under net metering tariffs that are modified under the Net Metering Act, such as the Company's proposed tariff NMS-2.

Q. WHAT LEGACY RIGHTS PROVISIONS WERE PROPOSED BY THE COMPANY AS PART OF NMS-2?

A. The Company did not propose any Legacy Rights provisions for NMS-2 customers. In other words, NMS-2 customers would have no certainty regarding their export compensation rate, net metering tariff terms and conditions, and underlying rate design, which the Company could propose to change at any time in the future.

Q. WILL NEW NET METERING CUSTOMERS RECEIVE ANY PROTECTIONS AGAINST FUTURE CHANGES TO THE TARIFF PROVISIONS, EXCESS GENERATION COMPENSATION RATE, OR APPLICABLE RATE DESIGN IF THE COMMISSION APPROVES TARIFF NMS-2?

A. No. In response to information requests, the Company confirmed that there will be no Legacy period under Tariff NMS-2.[42]

Q. WHY IS IT REASONABLE FOR NMS-2 CUSTOMERS TO BE PROVIDED CERTAIN LEGACY RIGHTS?

A. Net metering customers typically make a significant, long-term financial investments in a DG system. These customers are likely to be significantly and adversely affected by

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[42] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-1 and A-2.

changes to net metering terms and conditions, the compensation rate applicable to exported electricity, or underlying rate designs that were in place at the time the customer installed a net metering system, and particularly so by the types of changes that the Company has stated it is considering proposing in the future, such as new demand charges. Net metering customers are likely to rely on the reasonable assumption that historic rate trends and ratemaking practices will continue in the future. Without providing these customers with Legacy Rights, the changes being contemplated would be punitive for those DG customers, who would not know if, how, or when significant changes could occur that would have a material impact on their investment. Without having any certainty or ability to confidently forecast the financial benefits of a net metering facility, many customers are likely to forgo installing a new net metering system.

Q. WHAT LEGACY RIGHTS ARE REASONABLE FOR THE COMMISSION TO ESTABLISH FOR NMS-2 CUSTOMERS?

A. If the Commission approves NMS-2, or another modified net metering tariff, it should ensure these customers are provided Legacy Rights with respect to the rate structure, compensation rate for excess generation, and other terms and conditions that were in effect at the time their completed net metering application was submitted, as well as all other terms and conditions in the NMS-2 tariff.

Q. WHAT LEGACY PERIOD IS REASONABLE FOR NMS-2 CUSTOMERS?

A. A Legacy period of at least 25 years for customers taking service under NMS-2 is reasonable. This time period aligns with the Legacy period established by statute for NMS-1 customers and would provide a reasonable time period for customers to recoup their investment in a DG system without facing undue risk of adverse policy changes.

Furthermore, this time period would align with the 25-year performance warranty that is common for solar panels, which guarantees that the solar panel will not lose more than 20% of its output capacity during that time.[43]

Q. HOW WOULD MODIFICATIONS, ADDITIONS, OR REPAIRS TO AN EXISTING NET METERING FACILITY IMPACT A CUSTOMER'S ELIGIBILITY FOR NET METERING SERVICE UNDER THE COMPANY'S PROPOSAL?

A. According to the Company, "[r]outine maintenance and repairs do not require a new net metering application,"[44] and therefore would not compromise a customer's existing net metering facility from continuing to take service under the applicable net metering service tariff. Similarly, the Company states that repair and replacement of existing generating facility components with like components that do not result in increases in generating facility capacity is allowed without Company approval and would not impact a customer's Legacy Rights status.[45]

However, the Company interprets *any* changes or modifications to existing systems requiring submission of a new "Application for Interconnection and Net Metering" to terminate the Legacy Rights period.[46] It would mean that an existing net metering customer who later expands the size of the net metering facility would forfeit their Legacy Rights on the portion of their system that was installed pursuant to tariff NMS-1.

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[43] *See, e.g.*, Beren Argetsinger and Benjamin Inskeep, "Standards and Requirements for Solar Equipment, Installation, and Licensing and Certification: A Guide for States and Municipalities" Clean Energy States Alliance (February 2017), at 39.

[44] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-5(f).

[45] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-5(b).

[46] *Ibid*.

Q. HOW HAVE OTHER STATES ADDRESSED CHANGES OR MODIFICATIONS TO EXISTING SYSTEMS IN THE CONTEXT OF LEGACY RIGHTS?

A. States have generally allowed certain repairs, modifications, or replacements of existing equipment part of a net metering facility without a customer losing their Legacy Rights. For example, in California, NEM 1.0 customers continue to maintain their Legacy Rights so long as modifications to their net metering facility do not result in a 10% increase in generating capacity or a 1 kW increase in capacity, whichever is greater.[47] In general, newer solar panels have a higher capacity rating than comparable older solar panels. Providing for a 10% or 1 kW increase "buffer" allows a customer to make modifications to an existing system that might result in a small increase in the system capacity, such as from replacing an old solar panel that is no longer properly functioning with a newer panel, without losing their Legacy Rights.

Q. IS THE COMPANY'S PROPOSAL REGARDING MODIFICATIONS, ADDITIONS, OR REPAIRS TO AN EXISTING NET METERING FACILITY AS IT RELATES TO NET METERING LEGACY RIGHTS REASONABLE?

A. No. The Company's proposal is overly restrictive because it does not allow for *any* capacity increases, even very small increases, to a net metering facility that could occur should the customer replace an existing panel with a different type of panel (*e.g.,* if a "like" panel replacement is not an option for the customer, such as if the original solar panel manufacturer is no longer in business).

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[47] *See, e.g.,* Pacific Gas & Electric, "Electric Schedule NEM: Net Energy Metering Service" (Effective February 22, 2017).

Q. WHY ELSE IS THE ISSUE OF MODIFICATIONS OR ADDITIONS TO A NET METERING SYSTEM IMPORTANT IN THE CONTEXT OF NET METERING LEGACY RIGHTS?

A. Customers who have installed a solar net metering facility may subsequently wish to expand the size of their system. For example, a net metering customer may increase their annual energy usage over time as the size of the household grows and their energy consumption increases. A customer could also begin by installing a small solar net metering system that only partially offsets their annual energy usage and then gradually add additional solar panels, increasing the facility size over time as their budget allows.

Q. IS THE COMPANY'S INTERPRETATION THAT AN NMS-1 CUSTOMER WHO SUBSTANTIVELY INCREASES THE SIZE OF A NET METERING FACILITY AFTER TARIFF NMS-2 IS ADOPTED WOULD FORFEIT THE LEGACY RIGHTS ON THE ENTIRE SYSTEM REASONABLE?

A. No. It is not reasonable for an existing net metering system to lose its Legacy Rights based on the customer expanding the size of the Legacy net metering system. The statute expressly provides that the Legacy Rights "shall remain in effect at those premises for a twenty-five (25) year period," and makes no allowance for revoking those rights based on subsequent additions to the system. Regardless of how *new* capacity additions are addressed, the *existing* net metering facility capacity is guaranteed a 25-year Legacy Rights period.

In my opinion, a more reasonable approach would be to permit a customer to expand a net metering facility under Tariff NMS-1 up to the point where the system is designed to offset the customer's annual electricity consumption. Furthermore, the existing

45 kW maximum system size under net metering provides an additional "guardrail" on the extent to which an existing net metering facility can be expanded. Allowing capacity additions at NMS-1 facilities, subject to these two restrictions, is a reasonable approach to address customer desires to expand an existing facility while still limiting the overall size the system could be increased to.

Q. ARE LEGACY RIGHTS PROTECTIONS IN PLACE FOR OTHER TYPES OF LG&E AND KENTUCKY UTILITIES COMPANY ("KU") CUSTOMERS?

A. A number of tariffs offered by LG&E and KU provide Legacy Rights terms for participating or applicable customers. Notably, with respect to implementing new demand rates, all-electric schools in KU's service territory taking service on or before July 1, 2011, were allowed to continue to be served under a two-part rate schedule.[48] In addition, the Companies offer Legacy protections for customers served under predecessor rates to Rates GS and PS as of February 6, 2009.[49] The Company notes that that several thousand customers now receiving service under Rate GS or PS were eligible for such service in 2009 only as a result of the Legacy Rights provision, with only a small portion of these customers currently eligible for these rates based on current usage patterns without regard to the Legacy Rights provision.

Another pertinent example in the context of net metering is the Company's Solar Share Program. Under that offering, participating customers have the option to subscribe to capacity by paying the One-Time Solar Capacity Charge. These customers receive Solar Energy Credit values subject to the terms and conditions of this Rider for a period of 25 years. In response to an information request, the Company stated that "The rationale behind

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[48] Direct Testimony of William Seeyle, p. 51.
[49] Direct Testimony of Robert M. Conroy, p. 31.

providing a 25-year enrollment term for customers was to meet some customers' desire to have this option for themselves or as a gift to others. Additionally a 25-year guaranteed enrollment term aligns with the depreciation schedule for the solar array."[50] Similar logic would generally seem to apply to a residential customer investing in a solar net metering system. It would be unfair to future solar net metering customers to be subjected to a policy that provided no Legacy Rights at the same time the Company provides for a 25-year period for its potentially competing service offering through its Solar Share program.

Q. WHAT POTENTIAL FUTURE CHANGES COULD ADVERSELY IMPACT NMS-2 CUSTOMERS IF THE COMMISSION DOES NOT ESTABLISH LEGACY RIGHTS FOR THESE CUSTOMERS IN THIS PROCEEDING?

A. The Company's testimony identifies possible substantial changes in the future to rate design and the compensation rate for excess generation. The Company indicates that it may propose major rate design changes in the future, including moving net metering customers to a rate schedule with one or more demand charges. It also affirmed its intent to frequently change the credit export rate under NMS-2.[51] For instance, a solar net metering system installed under NMS-2 that generates electricity for a period of 30 years would experience *15 changes* in the export credit rate over that duration, assuming the Company updates its avoided cost rates every two years as it is currently required to do. While it is reasonable for the current rate schedule components to be adjusted over time for NMS-2 customers, as they are for other customers, customers taking service under NMS-2 should not be

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[50] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-6.
[51] Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, Dated January 8, 2021, A-1(c).

subsequently subjected to a different rate design or export credit rate on a non-voluntary basis.

Q. WHAT WILL BE THE LIKELY OUTCOME IF THE COMMISSION DOES NOT PROVIDE LEGACY RIGHTS TO NEW NET METERING CUSTOMERS?

Failure to provide clear and sufficient Legacy Rights to new net metering customers (*i.e.*, those taking service under NMS-2, should the Commission adopt the Company's proposal) in this proceeding would immediately chill the market for new net metering systems, *regardless* of the Commission's other determinations on net metering, including the specific export credit rate adopted. It is unlikely that a customer would undertake a 25- or 30-year investment if the customer only has two years of certainty with respect to the export credit rate, and potentially even less for rate design, depending on when the Company files its next rate case.[52]

52 Likewise, it would be similarly unlikely for the Company to voluntarily undertake a significant 30-year investment if the Commission only approved the prudency of the investment for an initial two-year period and the ability of the Company to recover its prudently incurred costs over the remaining 28-year lifespan was in question.

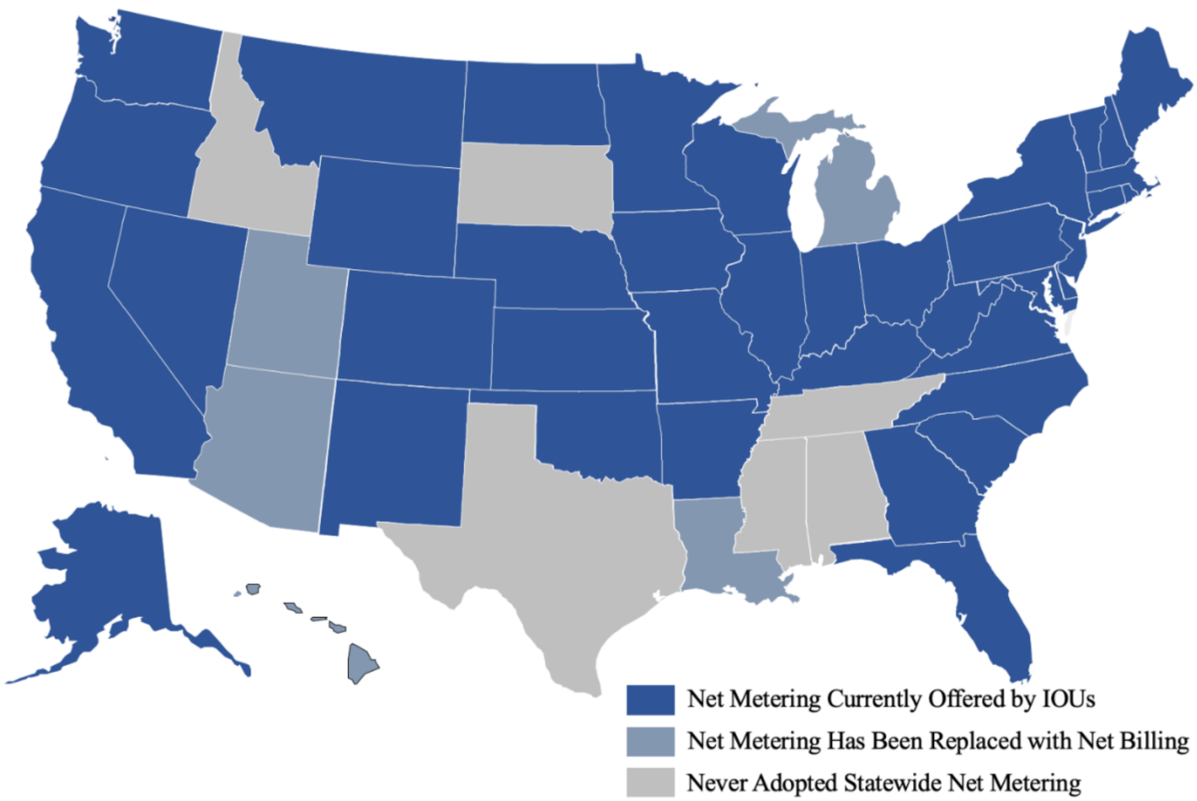
IV. NATIONAL NET METERING CONTEXT

A. Overview of Net Metering Policies

Q. HOW PREVALENT ARE NET METERING POLICIES IN THE UNITED STATES?

A. Net metering continues to be one of the most widespread and important DG policies across U.S. states and utilities. At its peak, investor-owned utilities ("IOUs") in at least 43 states and the District of Columbia offered net metering to customers. Currently, IOUs in approximately 39 states and the District of Columbia offer net metering to new residential and small commercial customers, as identified in Figure 1. Five states have transitioned from net metering to net billing for new residential and small commercial customers as of March 5, 2021. One state (Georgia) has recently created a new net metering program for its IOU, and two states (Nevada and Maine) ended net metering for a period of time and then restored net metering, albeit with some modifications.

Figure 1. Net Metering and Net Billing Availability for Residential and Small Commercial Investor-Owned Utility Customers



Q. WHAT FACTORS HELP EXPLAIN WHY NET METERING POLICIES HAVE BEEN POPULAR AND WIDELY ADOPTED IN THE U.S.?

A. Net metering offers a number of key advantages that have contributed to it becoming widely adopted, popular among customers, and effective at growing DG:

- **Understandable to customers.** Net metering makes sense to consumers. The simplicity of the 1:1 crediting of exports against imports over the duration of a billing period makes this policy understandable to customers and makes it simpler to estimate the financial benefits of a DG investment.

- **Technologically simple**. It does not take new or expensive metering equipment, such as advanced metering infrastructure ("AMI"), to implement net metering. Net metering can use existing metering equipment.
- **Fair compensation.** The 1:1 crediting of exports against imports over the duration of a billing period is generally perceived and accepted as a fair compensation rate by customers. In addition, numerous studies from across the country have shown this crediting rate is a reasonable approximation of the value provided by rooftop solar, particularly at low levels of rooftop solar deployment, as explained in further detail below.
- **Certainty.** Since compensation for monthly excess generation generally takes the form of kWh credits (or the equivalent expressed in dollars, based on the applicable volumetric retail rate), future changes to the utility's underlying kWh rates do not impact the economics of the system, as the customer continues to offset on a 1:1 basis grid exports and imports, giving a customer additional "peace of mind" about their financial investment.
- **Local economic development.** Net metering policies have proven effective at transforming nascent rooftop solar markets into significant job creators. Rooftop solar installer jobs are inherently local jobs and cannot be outsourced.

Q. HAVE STATES STUDIED THE COSTS AND BENEFITS OF NET METERING POLICIES OR THE VALUE PROVIDED BY SOLAR NET METERING SYSTEMS?

A. Yes, there have been numerous studies in recent years that have examined the costs and benefits of net metering or the value of solar DG or other distributed energy resources more broadly.

Q. WHAT HAVE THESE STUDIES FOUND REGARDING THE COSTS AND BENEFITS OR THE VALUE OF SOLAR DG?

A. Generally, these studies have found that net metering provides net benefits to all customers or only small net costs, prior to taking into consideration larger policy objectives (*e.g.*, local economic development) that extend beyond narrow cost-effectiveness tests (Figure 2). Similarly, studies calculating the value of solar DG have often found the total value exceeds the current retail rate. One recent review found that 14 out of 24 value of solar analyses conducted in 2012-2018 calculated that the value of solar was at or above the retail rate, and only one analysis calculated a value that was below 50% of the residential retail rate (Figure 3).

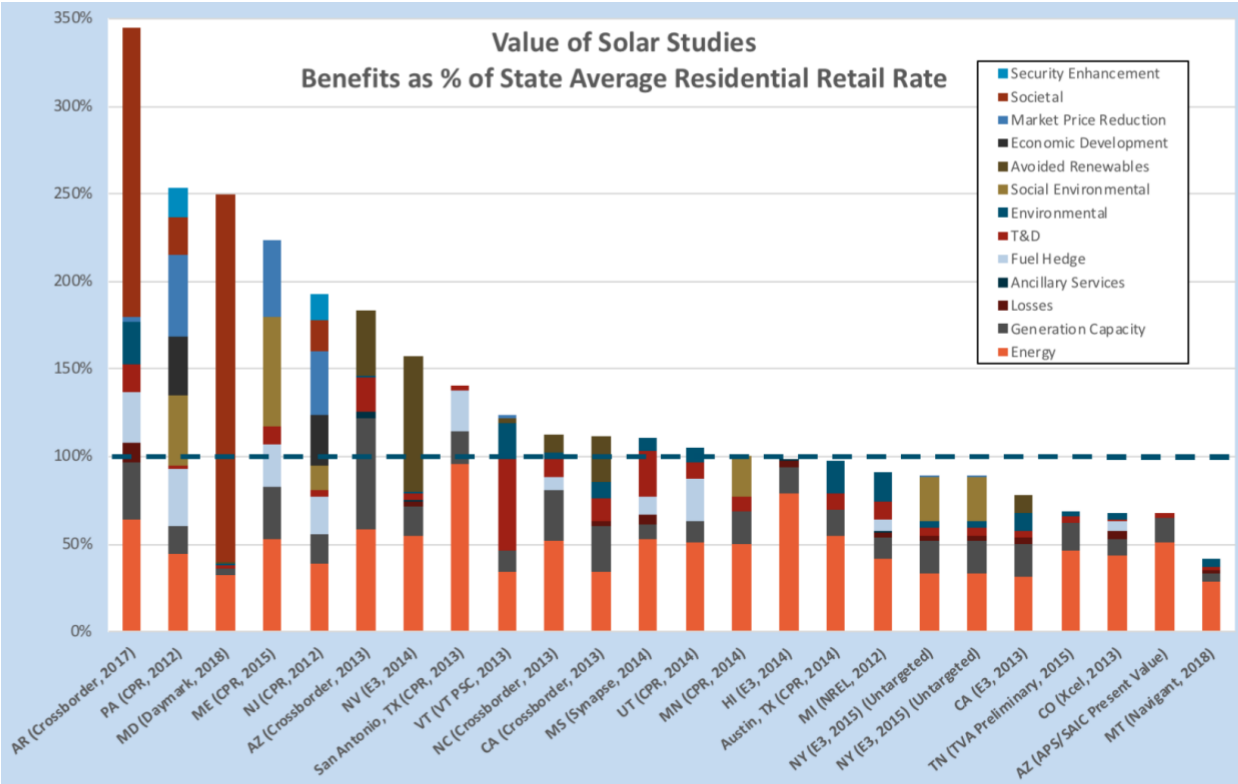
There is considerable variation across these studies in the methodology used, the categories of costs and benefits or values included, and the entity performing the study, which can all significantly impact the conclusions reached. Therefore, it is important that the specific context of a utility or state be fully evaluated in a rigorous and transparent way by an independent or neutral entity to determine what the impacts of net metering are in a specific jurisdiction.

Figure 2. Summary of State Cost-Benefit Study Results[53]

State	Year	Prepared by	Principal Findings
NEM Cost-Benefit Analysis			
Arkansas	2017	Crossborder	Benefits of residential distributed generation (DG) exceed the costs; do not impose a burden on other ratepayers.
Nevada	2016	E3	Cost-shift amounts to a levelized cost of $0.08/kWh for existing installations.
Louisiana	2015	Acadian	Costs associated with solar NEM installations outweigh their benefits.
South Carolina	2015	E3	NEM-related cost-shifting was *de minimus* due to the low number of participants.
Mississippi	2014	Synapse	NEM provides net benefits under almost all of the scenarios and sensitivities analyzed.
Vermont	2014	PSD	NEM results in "close to zero" costs to non-participating ratepayers, and may be a net benefit.
VOS/NEM Successor			
District of Columbia	2017	Synapse	Utility system VOS is $132.66/MWh (2015$); cost-shifting remains relatively modest.
Georgia	2017	Southern Company	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Hawaii	2015	CPR	Provides a methodology for assessing costs and benefits. Preliminary results suggest a net benefit.
Maine	2015	CPR	Value of distributed PV is $0.337/kWh (levelized).
Oregon	2015	CPR	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Minnesota	2014	CPR	Provides a methodology for assessing VOS; no specific estimate is produced.
Utah	2014	CPR	VOS is $0.116/kWh levelized.
DER Value Frameworks			
California	2016	CPUC	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
New York	2016	NY DPS	Provides a methodology for assessing costs and benefits; no specific estimate is produced.

53 ICF International, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar" (May 2018).

Figure 3. State Value of Solar Study Results[54]



B. Modifications to Net Metering Policies

Q. IN WHAT WAYS HAVE STATES MODIFIED NET METERING POLICIES IN RECENT YEARS?

A. I developed a table (Exhibit BDI-4) to identify which states have approved modified net metering policies or established a process for creating modified net metering or a net metering successor policy. It is important to reiterate that the vast majority of states continue to offer net metering to customers.

Exhibit BDI-4 shows that five states (Arizona, Hawaii, Louisiana, Michigan, Utah) have adopted net billing arrangements to replace an existing net metering policy. At least

[54] Kush Patel, "Act 236: Version 2.0," Energy+Environmental Economics (August 7, 2018). http://energy.sc.gov/files/Act%20236%20Follow%20Up%20-%20Stakeholder%20Meeting%2008.07.18_Final.pdf

10 states (Arkansas, California, Connecticut, Illinois, Indiana, Iowa, Kentucky, New Hampshire, New York, South Carolina) have articulated a process by which a modified net metering policy or net metering successor policy can be established, although the extent of the modifications remains largely unknown for most of these states.

Q. WHAT DO YOU MEAN BY A "MODIFIED NET METERING" POLICY?

A. I use the term "modified net metering" to refer to recent policy changes that continue the fundamentals of net metering, including monthly netting at or near the full applicable retail rate, but where certain aspects of the net metering policy, such as the credit rate for monthly excess generation, was modified.

For example, California's modified net metering policy, "NEM 2.0," was adopted in 2016 and applied to IOUs once they reached their net metering cap, or beginning July 2017, whichever came first.[55] Like net metering customers under the original net metering policy, NEM 1.0, NEM 2.0 customers continue to be able to self-consume electricity generated by their net metering system and net any excess generation against imported electricity over a monthly billing period. However, unlike NEM 1.0 customers, NEM 2.0 customers must take service under a time-of-use rate schedule and are required to pay all non-bypassable charges (*e.g.*, bill surcharges that fund public purpose programs that are outside of base rates) for all electricity imported from the grid.

Q. WHAT DO YOU MEAN BY A "NET METERING SUCCESSOR" POLICY?

A. I use the term "net metering successor" to refer to a policy that replaces net metering. As described in more detail above, one example of a net metering successor policy that has been adopted in five states is net billing.

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55 California Public Utilities Commission, Decision 16-01-004.

Q. ARE THERE ANY OTHER WAYS THAT STATES HAVE MODIFIED POLICIES RELATED TO DG COMPENSATION?

A. Changes to rate design applicable to DG customers have also been considered in numerous proceedings. For instance, some utilities have proposed adding a monthly capacity-based charge on DG customers, using monthly minimum bills, or moving DG customers onto time-of-use rates.

Q. HOW DOES THE COMPANY'S PROPOSED TARIFF NMS-2 COMPARE TO NET METERING MODIFICATIONS ADOPTED IN OTHER JURIDICTIONS?

A. Over the last decade, net metering has been extensively studied and investigated in many jurisdictions across the country.[56] The Company's proposed Tariff NMS-2 would be more far-reaching and more detrimental than modified net metering policies adopted in most of these jurisdictions, and its position on Legacy Rights for new net metering customers would be among the worst Legacy Rights policies in the country for modified net metering customers.

More fundamentally, the Company's proposal stands out when compared to most modified net metering policies that have been adopted in other jurisdictions for its lack of underlying support and justification. Other jurisdictions, especially those that have higher penetration rates of net metering, have undergone extensive investigation, study, and evaluation of net metering and DG policies more broadly over a period of several years *prior* to making significant modifications to net metering that were not expressly directed by legislation. Typically, state utility regulators have overseen investigations into net metering policies that include studies that quantify the costs and benefits of net metering

[56] *See, e.g.,* ICF International, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar" (May 2018).

or the value of distributed energy resources like solar prior to making significant changes. The most common outcome of these proceedings is that the state utility commission adopts only limited and incremental changes to the overall design of the net metering policy. Some states have gone through multiple iterations of this process, spanning multiple years, to collect evidence, gather input from a variety of parties, implement adjustments, monitor the results, and then restart the process in an iterative fashion to consider additional refinements.

For instance, the California Public Utilities Commission ("CPUC") opened Rulemaking ("R.") 14-07-002 in 2014 to study the impacts of net metering and examine tariff modifications to net metering. Ultimately, a modified net metering tariff, NEM 2.0, was adopted in 2016. In 2020, the CPUC opened R.20-08-020 to develop a successor tariff to NEM 2.0, to be implemented for new customers beginning in 2022.

I have developed Exhibit BDI-5 to highlight a selection of jurisdictions that have examined net metering policies. The table identifies examples of studies that have been conducted, key regulatory proceedings that have investigated these issues, and a summary of the net metering outcomes for each jurisdiction examined. The table is meant to be illustrative, and not entirely comprehensive of every jurisdiction, study, and docket.

Q. HAVE JURISDICTIONS WITH HIGH NET METERING ADOPTION RATES MAINTAINED NET METERING POLICIES?

A. Yes. As shown in Exhibit BDI-5, many states with high net metering adoption rates have continued to offer net metering or modified net metering, while rejecting more significant changes or multiple changes that in combination could be detrimental to prospective net metering customers. For example, a number of states have kept retail-rate crediting during the billing month, but reduced the compensation rate for net excess generation that is rolled over to subsequent billing months, such as Nevada and New Hampshire.

Q. WHAT TYPES OF NET METERING MODIFICATIONS HAVE BEEN ADOPTED IN OTHER JURSIDICTIONS WITH HIGHER NET METERING ADOPTION RATES?

A. Table 1 presents a high-level summary of some attributes of modified net metering policies that have been adopted in jurisdictions with higher net metering adoption rates. It illustrates that even in jurisdictions with far more net-metered systems installed than in Kentucky, policymakers have determined that maintaining the overall structure of net metering continues to be in the interest of customers. Importantly, modifications to net metering were adopted in most of these states only after significant amounts of net metering systems were installed and the impacts of net metering was thoroughly analyzed.

Table 1. Comparison of Attributes of Modified Net Metering Policies in Selected States

State (Utility)	Mandatory TOD	Special Solar Rate	Incremental Fixed Charge	Minimum Bill	Capacity Fee	Excess Generation Credit	Legacy Rights Term
Arizona (APS)	Yes	No	No	No	$0.93/kW (avoid with demand rate)	Monetary export rate for all exports (10% limit on annual decline and 10-year rate lock-in)	10-year term
Arizona (TEP)	No	No	No	No	No	Monetary export rate for all exports (10% limit on annual decline and 10-year rate lock-in)	10-year term
California	Yes	No	No	No	No	Retail rate by TOU period	20-year term
Connecticut *"Netting Tariff" described here. Buy-all, sell-all option also will be offered.*	No	No	No	No	No	Monetary export rate set at retail rate	20-year term
Hawaii	No	No	No	No	No	Monetary export rate for all exports	Export rate fixed through 2022
Massachusetts	No	No	No	TBD	No	Retail less public purpose charges	N/A
New Hampshire	No	No	No	No	No	Retail less 75% of distribution rate	Up to 23 years (through 2040)
New York	No	No	No	No	$0.69 - $1.09/kW (public purpose	Retail rate for residential, small commercial, and BTM	N/A
Nevada	No	No	No	No	No	For residential customers, retail rate during the month. Monthly excess credited based on a declining schedule based on installed capacity; currently, 75% of retail rate for monthly excess (the lowest of the four compensation tiers)	20-year term

South Carolina (DEC/DEP) *Proposed memorandum of understanding on Solar Choice Net Metering*	Yes	No	No	$30	$3.95-$5.86/kW (15 kW or larger)	Imports and exports netted within each TOD pricing period; net exports credited at avoided cost	10-year term
Texas (EPE)	No	No	No	$30 (Standard); $26.50 (TOD)	No	Monthly credit at avoided cost	10-year or 25-year term
Vermont	No	No	No	No	No	Average retail + adders	10-year term

Q. WHAT OTHER OBSERVATIONS DO YOU HAVE IN COMPARING NET METERING MODIFICATIONS IN THE CONTEXT OF THE COMPANY'S PROPOSAL IN THIS CASE TO OTHER STATE NET METERING POLICIES?

A. Several things stand out. First, the Company has a comparatively low solar DG adoption rate relative to most IOUs in states identified in Exhibit BDI-4 that have established modified net metering policies or adopted net metering successor policies. This is significant because the policies that are appropriate for a nascent solar market like in the Company's service territory will inherently be different from states with higher levels of solar adoption.

Second, Kentucky's 45 kilowatt ("kW") maximum system size for net metering system eligibility is among the most restrictive. In comparison, the neighboring states of Illinois allows systems up to 2,000 kW, for example.

Third, Kentucky's 1% net metering cap is smaller than the net metering cap in most states. Like maximum system size restrictions, a net metering cap limits the growth of net metering, as well as any associated impacts – positive or negative – of solar DG.

Finally, most states have maintained net metering policies until after their net metering cap has been reached, and even then, the cap is often extended. In the present case, the Company has proposed major changes to net metering even though it is far below its net metering cap.

Q. WHAT OBSERVATIONS DO YOU HAVE REGARDING BEST PRACTICES USED WHEN CONSIDERING MODIFICATIONS TO NET METERING BASED ON YOUR REVIEW OF NET METERING IN OTHER JURISDICTIONS?

A. There are several commonalities among many jurisdictions in how they have considered modifications of net metering, many of which I think align with the directives of the Net Metering Act. At a high level, some of the "best practices" evident from these examples for policymakers to consider when evaluating modifications to net metering policies are:

- **Quantitative analysis is key:** Cost of service studies, cost-benefit analyses, and value of solar (or distributed energy resources more broadly) studies, or a combination thereof, have been used to quantify the impacts of net metering. These studies have been paramount in informing discussions of net metering policy changes, although they are not necessarily dispositive of the ultimate outcome, as larger policy considerations have also played an important role in shaping discussions. They can also be helpful in identifying policy solutions that align net metering customer incentives with broader grid benefits in a manner that does not discourage the adoption of DG. This is consistent with the Net Metering Act's delegation to the Commission to establish the compensation rate for exported electricity and its authority to set rates that are fair, just, and reasonable.

- **<u>Gradualism is an important ratemaking principle:</u>** After gathering robust evidence on net metering implementation, public utility commissions that have determined that changes should be made to existing net metering policies have adhered to the ratemaking principle of gradualism by implementing modest changes. For example, New Hampshire has maintained monthly retail rate netting, excluding non-bypassable charges, and implemented a reduced credit rate for the rollover credit at the end of the month, while it undertakes a multi-year study into DERs to collect additional data. Even states that ultimately ended retail rate net metering and replaced it with net billing, such as Utah and Louisiana, only did so after many years, multiple investigations, and a transition period where a modified policy was in place that limited the immediate financial impacts on prospective net metering customers.
- **<u>Iterative process:</u>** Net metering policy discussions are rarely resolved through one proceeding. Rather, the proliferation of rooftop solar has led many policymakers to study and evaluate net metering and successor policies on an iterative basis, incorporating new information as additional experience is gained and data is collected. This is consistent with the Net Metering Act's provision directing each utility to propose DG compensation rates in rate cases initiated by the utility.[57]
- **<u>Insufficiently supported utility proposals are rejected.</u>** Numerous utility requests to modify net metering policies or related rate design changes impacting net metering customers have been rejected by regulators across the U.S. when they have not been adequately supported and justified by the utility. Regulators have been reluctant to make drastic changes to net metering that could undermine customer adoption of

[57] KRS 278.466(3).

rooftop solar when the utility has not met its burden to demonstrate that its proposed changes result in just and reasonable rates and are in the public interest. In other words, regulatory determinations on net metering parallel those made in ratemaking as a whole, requiring utilities to meet the same burden of proof standard that applies more generally. Such a standard is critical for ensuring that adopted policies or rates are not discriminatory. This is consistent with the Commission's prior decisions described above in Kentucky Power's 2020 rate case in which the Commission deferred its decision on proposed Tariff NMS II, finding it had been insufficiently supported.

- **Retail rate net metering remains commonplace.** Despite numerous proceedings and legislation addressing net metering in states across the country, retail rate net metering remains one of the most widespread distributed generation policies currently in place in the U.S., with approximately 39 states offering net metering to residential and small commercial customers. The Commission was delegated the authority under the Net Metering Act to set the compensation rate for electricity fed back to the grid by a net metering customer, which it could set as the applicable volumetric retail rate.

Q. WHY HAVE SOME STATES ADOPTED MODIFIED NET METERING POLICIES OR NET METERING SUCCESSOR POLICIES IN RECENT YEARS?

A. Two factors are driving this trend. First, rooftop solar deployment has increased in recent years, driven by rapid cost declines. Most state net metering policies specify an aggregate capacity limit for net metering programs ("net metering cap"). Often, state legislatures and utility regulators have responded to utilities nearing or exceeding the specified net metering cap as a result of the proliferation of DG solar by increasing the net metering cap and/or by adopting policies to modify net metering or establish a pathway for adopting a net metering successor policy, which is often preceded by a study or formal investigation.

Second, utilities, their trade associations, and other aligned interests have waged a long-running campaign against policies encouraging the adoption of rooftop solar, particularly net metering.[58] Net metering allows a customer to purchase less electricity from a utility, which can result in a decrease in a utility's revenue. In addition, electric utilities earn profit by making capital investments, on which they are permitted the opportunity to earn a return on equity. Investment in generation facilities such as solar DG by utility customers can therefore compete with a utility's generation investments, with a reduced need in new utility generation assets corresponding to a reduced profit opportunity for the utility. In states without retail choice, rooftop solar is one of the few examples of a utility facing a form of competition, as utility customers are otherwise stuck with being served by the electricity generated or procured by their monopoly utility and cannot chose their supplier.

Q. IS THE COMPANY EXPERIENCING SUBSTANTIAL DEPLOYMENT OF NET METERING IN ITS SERVICE TERRITORY?

A. No. Currently, the Company only has 655 net metering customers[59] out of approximately 419,000 total customers in Kentucky, or about 0.16% of customers.

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[58] *See, e.g.,* Joby Warrick, "Utilities Wage Campaign Against Rooftop Solar," *Washington Post* (March 7, 2015); Hye-Jin Kim, Rachel J. Cross, and Bret Fanshaw, "Blocking the Sun: Utilities and Fossil Fuel Interests That Are Undermining American Solar Power," Frontier Group and Environment America Research & Policy Center (November 2, 2017); Gabe Elsner, "Edison Electric Institute Campaign Against Distributed Solar," Energy and Policy Institute (March 7, 2015); *See Generally,* Energy and Policy Institute, "Category: Net Metering," https://www.energyandpolicy.org/category/solar/net-metering/.

[59] LG&E February 24, 2021 Supplemental Response to Kentucky Solar Industries Association, Inc.'s Initial Requests for Information, A-14(c).

Q. ARE THERE RECENT EXAMPLES OF STATE UTILITY REGULATORS ELIMINATING OR MAKING SUBSTANTIAL CHANGES TO NET METERING FOR AN IOU WITH A LOWER NET METERING CUSTOMER ADOPTION RATE THAN THE COMPANY CURRENTLY HAS UNDER TARIFF NMS-1?

A. Not that I am aware of. Both KU and LG&E have net metering adoption rates of less than 0.2% of their customers. In contrast, major changes to net metering in other states have generally occurred only *after* significant amounts of solar net metering was deployed.

For example, in Hawaii, regulators ended net metering in October 2015,[60] when IOUs Hawaiian Electric Company, Maui Electric Company, and Hawaii Electric Light Company had 39,926 net metering customers, 8,922 net metering customers, and 9,233 net metering customers, respectively.[61] In comparison, these utilities had total customer counts in 2015 of 302,499 customers, 70,284 customers, and 83,860 customers, resulting in net metering customer adoption rates of 13.2%, 12.7%, and 11.0%, respectively.

In contrast, state regulators have often rejected or deferred consideration on net metering changes when IOUs do not have significant solar net metering deployment. For instance the Arkansas Public Service Commission ("Arkansas PSC") issued an Order on June 1, 2020, addressing implementation of Act 464 (2019). Even though Act 464 authorized the Arkansas PSC to make changes to net metering, it elected to maintain retail-rate net metering for the time being for residential and small commercial customers. The Order does allow utilities to propose net metering alternatives in the future for residential

[60] Docket No. 2014-0192, *Instituting a Proceeding to Investigate Distributed Energy Resource Policies* (Hawaii Public Utilities Commission).
[61] U.S. EIA Form 861M.

and small commercial customers, but not until after 2022.[62] At the time of this Order, Entergy Arkansas, Southwestern Electric Power Company, Oklahoma Gas & Electric, and Empire District Electric had 882 net metering customers, 264 net metering customers, 93 net metering customers, and 22 net metering customers, respectively. In comparison, the utilities had total customer counts of 713,072 customers, 121,474 customers, 67,599 customers, and 4,771 customers, respectively, resulting in net metering adoption rates of approximately 0.1%, 0.2%, 0.1%, and 0.5%, which are similar to the net metering adoption rates of LG&E and KU in Kentucky.

Q. HAVE STATE UTILITY REGULATORS DECIDED TO RETAIN THE FUNDAMENTAL POLICY DESIGN OF NET METERING AFTER CONDUCTING A REVIEW OR INVESTIGATION INTO THE POLICY?

A. Yes. In fact, maintaining the status quo net metering policy or only making modest modifications to net metering or related issues, such as rate design for DG customers, has frequently been the outcome of state proceedings that have addressed net metering policies in recent years. In states with relatively modest customer net metering adoption rates, regulators have typically preserved net metering in its current form, or only made modest changes that would not fundamentally alter the viability of solar net metering, <u>even when the utility regulator is acting to implement new legislation authorizing changes to net metering</u>.

Q. CAN YOU PROVIDE SPECIFIC EXAMPLES OF STATE UTILITY REGULATORS RETAINING THE FUNDAMENTAL POLICY DESIGN OF NET METERING AFTER STATE NET METERING LEGISATION WAS ENACTED?

[62] Docket No. 16-027-R, *In the Matter of Net Metering and the Implementation of Act 827 of 2015* (Arkansas Public Service Commission).

A. In 2014, the Oklahoma legislature enacted Senate Bill 1456, which is similar to the Net Metering Act in that it (a) provides for rates based on the full cost to serve DG customers, (b) prohibits DG customers from being subsidized by customers in the same class, (c) refers to fixed charges as a means of addressing potential subsidies (*i.e.*, referring to a fixed charge as "reflecting the actual fixed costs of the retail electric supplier"), and (d) provides for the subsidy prohibition to take effect on the effective date of the law.

When the Oklahoma Corporation Commission first considered the issue of potential cross-subsidization, it found that while OG&E's existing tariffs "could" create the opportunity for cross-subsidies that benefit DG customers, it was not persuaded that OG&E had demonstrated the existence of a subsidy based on the record in the case.[63] The OCC further stated that it was not convinced that OG&E's proposed DG tariffs—which included the imposition of demand charges—would result in charging DG customers "only the amount required to recover the full costs necessary" to serve them. The issue was referred to OG&E's then-pending rate case and, as part of the subsequent stipulation settling the case, the demand charges proposed by OG&E were removed.

More recently, the Arkansas PSC rejected major changes to net metering proposed by utilities even though it was implementing the Arkansas state legislature's Act 464 (2019), which granted it authority to make substantial modifications to the net metering policy. It decided that "Based upon the evidence currently showing very low levels of penetration of renewable distributed generation by solar facilities in Arkansas in the residential class and in any non-residential customers without a demand component, the Commission finds that the current 1:1 full retail credit for net excess generation should be

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[63] Oklahoma Corporation Commission, Order No. 651669, Cause No. PUD 201500274, p. 21, *available at*: https://imaging.occ.ok.gov/AP/Orders/occ5274851.pdf.

retained for now as the default Net-Metering rate structure," (footnote omitted).[64] The decision permits utilities to propose more substantive changes through filings submitted after December 31, 2022, but requires the utilities to justify such a proposal by using a "timely and properly designed cost-of-service study" that demonstrates the net metering alternative is "in the public interest and will not result in an unreasonable allocation of or increase in costs to other utility customers."[65]

Q. HAVE STATE REGULATORS EXPANDED NET METERING AFTER CONDUCTING A REVIEW OR INVESTIGATION INTO THE POLICY?

Yes. For instance, the Iowa Utilities Board issued an Order in July 2016 maintaining net metering after conducting an investigation into its net metering policy.[66] The Order created a three-year study process, while expanding the availability of net metering to all customer classes and increasing the maximum eligible system size from 500 kW to 1,000 kW.

More recently, the Georgia Public Service Commission modified the DG compensation policy in place for Georgia Power in December 2019 by changing the netting period from instantaneous (*i.e.*, net billing) to monthly (*i.e.*, net metering) for the first 5,000 participating rooftop solar customers or until the new installed capacity reaches 32 megawatts, whichever comes first.[67]

Q. HAVE STATE LEGISLATURES ACTED TO RESTORE NET METERING AFTER REGULATORS ISSUED DECISIONS REPLACING THE POLICY?

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[64] Order, Docket No. 16-027-R, *In the Matter of Net Metering and the Implementation of Act 827 of 2015* (Arkansas Public Service Commission June 1, 2020), p. 525.

[65] *Ibid*.

[66] Docket No. NOI-2014-0001, *Inquiry into Technical, Legal, and Policy Related to Distributed Generation* (Iowa Utilities Board July 19, 2016).

[67] Docket No. 42516, *Georgia Power Company 2019 Base Rate Case* (Georgia Public Service Commission February 6, 2020).

A. Yes, in two cases. In Nevada, the state legislature enacted Assembly Bill 405 in 2017, restoring retail rate net metering for small customers after the Public Utilities Commission of Nevada issued a decision in 2016 that severely reduced the financial benefits that would be realized by net metering customers, resulting in widespread backlash by customers and thousands of job losses.[68] Likewise, in Maine, the state legislature restored net metering in 2019 after utility regulators initially issued revised rules in March 2017 that replaced net metering with a buy-all, sell-all compensation structure.[69]

Q. WHY ARE OTHER STATES' POLICY DECISIONS ON NET METERING OR DG POLICY IN GENERAL RELEVANT TO THIS PROCEEDING?

A. All states and their Commissions value their autonomy. Their policy decisions are governed by their unique legal frameworks, policy priorities, and objectives. Despite these inherent differences, it is significant that after substantial focus on net metering policies in recent years, most states have elected to expand or maintain existing net metering policies, make only modest changes that retain the fundamentals of net metering, or establish a future process for considering changes to net metering while allowing customers to continue to net meter in the interim. When state policymakers have moved forward with changes to net metering policies, they have often done so after first experiencing significant growth in net metering adoption, and only then after studying or investigating the policy and its impacts, and carefully considering the appropriate changes after developing and weighing a robust record. Decisions in other states provide insight into the range of options available, common principles, and best practices.

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[68] *See, e.g.*, Jeff St. John, "Nevada's Solar Job Exodus Continues, Driven by Retroactive Net Metering Cuts," Greentech Media (January 8, 2016).

[69] Docket No. 2016-00222, *Commission Rulemaking Amendments to Net Energy Billing Rule Chapter 213* (Maine PUC).

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission reject the Company's proposed Tariff NMS-2, as the Company has failed to meet its burden of proof and has not demonstrated that it will result in rates that are fair, just, and reasonable.

To the extent the Commission determines changes are needed to the Company's Tariff NMS to comply with statutory changes enacted through the Net Metering Act, I recommend that the Commission only direct the Company to modify Tariff NMS to reflect the Net Metering Act's definitional change of net metering with respect to "dollar value" bill credits by specifying that the "dollar value" for electricity fed back to the grid by a net metering customer is the volumetric retail rate applicable to the net metering customer.

To the extent the Commission approves Tariff NMS-2 or establishes a new tariff in this proceeding separate from Tariff NMS applicable to new net metering customers, I recommend the Commission ensure the changes reflect both the long-term costs and the benefits of net metering, adhere closely to the principle of gradualism, be informed by the modified net metering best practices established in other U.S. jurisdictions, and protect new net metering customers by adopting Legacy Rights protections for these customers. Specifically, I recommend a 25-year Legacy period with respect to rate design, compensation rate, and other tariff terms and conditions. I also recommend that the Commission allow net metering customers to expand the size of a Legacy net metering facility up to the customer's forecasted annual electricity usage or 45 kW, whichever is less, without forfeiting their Legacy Rights. Regardless of whether the Commission adopts this recommendation, I recommend that it allow customers to replace components of a net metering system, such as solar panels, without forfeiting Legacy Rights, even if it results in modest increases in the total system capacity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit BDI-1: *Curriculum Vitae* of Benjamin D. Inskeep

Benjamin D. Inskeep

binskeep@eq-research.com

EDUCATION

School of Public and Environmental Affairs (SPEA), Indiana University, Bloomington, IN
M.S. in Environmental Science, 2012, Top GPA Award
Master of Public Affairs, 2012, Top GPA Award, Concentration: Environmental Policy

"IU at Oxford," University of Oxford, Oxford, United Kingdom
Six-week graduate school program on climate change governance and environmental regulation, 2011

Indiana University, Bloomington, IN
B.S., Psychology, 2009, with *Highest Distinction*, Honors Notation, and Phi Beta Kappa honors
Certificate, Liberal Arts and Management Program (honors-level interdisciplinary business program)

EXPERIENCE

Principal Energy Policy Analyst, February 2020 – Present
Senior Energy Policy Analyst, January 2019 - Present
Energy Analyst, May 2018 – December 2018
Independent Contractor, July 2017-April 2018
Research Analyst, March 2016 – June 2017
EQ Research LLC, Cary, North Carolina

- Lead EQ Research's CCA services focused on regulatory monitoring, compliance reporting, and customized research and analysis.
- Develop expert witness testimony, clean energy legislation, policy memos, regulatory public comments, policy reports, and market analyses with an emphasis on clean energy policy.
- Research, track, and analyze renewable energy legislation, regulatory proceedings, and stakeholder opportunities to participate in policymaking for client-facing policy tracking services.
- Manage EQ Research's services on U.S. electric utility rate cases including reviewing and summarizing all rate cases, researching and tracking anticipated rate cases and providing bi-weekly updates to clients on utility rate developments.
- Support and collaborate with a diverse regulatory team, including attorneys, policy analysts, businesses and environmental advocates, in ongoing regulatory proceedings.

Researcher, August 2017 – January 2018
Earth Island Institute, Indianapolis, Indiana

- Developed more than 100 wiki pages on existing and planned coal, LNG terminals and oil and gas pipelines for the CoalSwarm and FrackSwarm projects, which provide clearinghouses addressing the impacts of coal and fracking and moving to cleaner sources of energy.

Policy Analyst, June 2014 – March 2016
North Carolina Clean Energy Technology Center, N.C. State University, Raleigh, North Carolina

- Co-creator, lead author, and editor for *The 50 States of Solar*, a quarterly report series that comprehensively tracks state regulatory and legislative distributed solar policy developments.
- Created an internal database for tracking distributed solar regulatory and legislative policy proposals, and queried and analyzed the data to answer policy questions, identify trends, and develop reports.

- Tracked and updated summaries of more than 500 utility, local, state, and federal policies and incentives for the *Database of State Incentives for Renewables and Efficiency* (DSIRE).
- Led solar workshops and provided technical assistance to local governments, including solar financial and policy analysis, reports, case studies, fact sheets, and customer-facing solar guides as part of the U.S. Department of Energy SunShot Solar Outreach Partnership.

Doctoral Research Assistant, August 2012 – December 2013
SPEA, Indiana University, Bloomington, Indiana
- Completed three semesters of Ph.D. coursework, attaining a 4.0/4.0 GPA.
- Collaborated with Professor Shahzeen Attari in academic research projects on the psychology of energy and water use and conservation.
- Lead-authored peer-reviewed research on the most effective actions households can take to curb water use.

Climate Corps Fellow, June 2012 – August 2012
Environmental Defense Fund, Cary, North Carolina
- Quantitatively benchmarked the energy efficiency of 90+ North Carolina fire stations and authored case studies highlighting the most effective local fire station energy efficiency initiatives.
- Evaluated the cost-effectiveness of various local government energy efficiency measures to demonstrate the financial value of sustainability.

Sustainability Intern, October 2011 – April 2012
Office of Sustainability, Indiana University, Bloomington, Indiana
- Analyzed data on Indiana University's energy use to determine greenhouse gas emission trends.
- Collected and analyzed quantitative and qualitative sustainability metrics for sustainability ratings.
- Benchmarked the university's sustainability relative to peer institutions.

Research Intern, February 2010 – May 2010
The Nature Conservancy, Indianapolis, Indiana
- Synthesized research on the economic benefits of community green space as part of a white paper.

PUBLICATIONS

- Inskeep, B. **Pollinator-Friendly Solar in Indiana.** May 2020. Published by EQ Research.
- Inskeep, B. **Four Flavors of Grid Modernization in the Midwest.** April 12, 2019. Published by EQ Research.
- Inskeep, B. **States Charting Paths to 100% Targets.** March 15, 2019. Published by EQ Research.
- Makhyoun, M. and B. Inskeep, **Ten Things to Know about CCAs in California.** February 13, 2019. Published by EQ Research.
- Inskeep, B. **EQ Research's Q4 2018 GRC [General Rate Case] Update.** January 15, 2019. Published by EQ Research.
- Inskeep, B. **EQ Research's Q3 2018 GRC Update.** October 16, 2018. Published by EQ Research.

- Argetsinger, B. and B. Inskeep. **Standards and Requirements for Solar Equipment, Installation, and Licensing and Certification.** January 2017. Published by the Clean Energy States Alliance.
- Barnes, C., J. Barnes, B. Elder, and B. Inskeep. **Comparing Utility Interconnection Timelines for Small-Scale Solar PV, 2nd Edition.** October 2016. Published by EQ Research.
- Barnes, J., B. Inskeep, and C. Barnes [with Synapse Energy Economics]. **Envisioning Pennsylvania's Energy Future.** October 2016. Published by the Delaware Riverkeeper Network.
- Inskeep, B., et al. **The 50 States of Solar.** February 2015, April 2015, August 2015, November 2015, February 2016. Lead author & editor for five quarterly editions. Published by the NC Clean Energy Technology Center.
- Inskeep, B., et al. **Utility Ownership of Rooftop Solar PV.** November 2015. Published by U.S. DOE SunShot Solar Outreach Partnership.
- Inskeep, B., and A. Proudlove. **Renewable Cities: Case Studies.** Published by U.S. DOE SunShot Solar Outreach Partnership, October 2015.
- Inskeep, B., K. Daniel, and A. Proudlove. **Delaware Goes Solar: A Guide for Residential Customers.** June 2015. Published by U.S. DOE SunShot Solar Outreach Partnership.
- Inskeep, B., and A. Proudlove. **Homeowner's Guide to the Federal Investment Tax Credit for Solar PV.** Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Inskeep, B., and A. Proudlove. **Commercial Guide to the Federal Investment Tax Credit for Solar PV**. Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Daniel, K., B. Inskeep, and A. Proudlove. **Understanding Sales Tax Incentives for Solar Energy Systems.** Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Inskeep, B. and A. Shrestha. **Comparing Subsidies for Conventional and Renewable Energy.** Published by NC Clean Energy Technology Center, March 2015.
- Inskeep, B., K. Daniel, and A. Proudlove. **Solar on Multi-Unit Buildings: Policy and Financing Options to Address Split Incentives.** Published by U.S. DOE SunShot Solar Outreach Partnership, February 2015.
- Daniel, K., B. Inskeep, et al. **In-State RPS Requirements**. Published by NC Clean Energy Technology Center, November 2014.
- Inskeep, B. and S. Attari. **The Water Short List: The Most Effective Actions U.S. Households Can Take to Curb Water Use.** *Environment: Science and Policy for Sustainable Development* 56, No. 4, 2014: 4-15.

PARTICIPATION AT PUBLIC UTILITY COMMISSIONS

- **Kentucky Public Service Commission**, *October 2020 and February 2021*, Provided direct and supplemental testimony on behalf of Kentucky Solar Energy Industries on Kentucky Power Company's net metering proposal, Case No. 2020-00174.
- **Kentucky Public Service Commission,** *November 2019*, Provided comments on behalf of Kentucky Solar Energy Industries on the implementation of the Net Metering Act, Case No. 2019-00256.

- **Indiana Utility Regulatory Commission,** *September 2019*, Provided public comments as a ratepayer at Public Hearing against Indianapolis Power and Light's (IPL) proposed $1.2 billion grid modernization plan that would raise customer bills by $10.50.
- **Indiana Utility Regulatory Commission,** *May 2018,* Provided public comments as a ratepayer at Public Hearing against IPL's proposal in its rate case to increase it fixed customer charge from $17 to $27, which would have been the highest fixed charge among investor-owned utilities in the nation.

PRESENTATIONS

- **Indiana's Energy Transition**, November 2020
  Presentation at Hoosier Environmental Council's "Greening the Statehouse"
- **Energy Storage in Integrated Resource Planning**, September 2020
  Panelist on webinar hosted by the Energy Storage Association
- **DERs [Distributed Energy Resources] in the Midwest**
  Moderated panel at Solar and Storage Midwest, November 2019
- **Planning for the Solar Revolution**
  Poster presentation at Solar Power International, Salt Lake City, Utah, September 2019
- **Policy Considerations for Accelerating the U.S. Clean Energy Transition**
  Invited by Prof. Sanya Carley to give lecture to graduate energy economics class at Indiana University School of Public and Environmental Affairs, Bloomington, Indiana, March 2019.
- **Solar Equipment, Installation, and Licensing & Certification: A Guide for States and Municipalities**
  Webinar presentation on report findings sponsored by the Clean Energy States Alliance, February 2017.
- **Distributed Solar PV Trends in Net Metering and Rate Design**
  Invited to give presentation at Solar Asset Management Conference, San Francisco, California, March 2016.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at Kerr-Tar Councils of Government, Henderson, North Carolina, November 20, 2015.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at NC Clean Energy Technology Center, Raleigh, North Carolina, November 19, 2015.
- **North Carolina in Context: Regional and National Trends**.
  Panel presentation at University of North Carolina Clean Energy Forum, Chapel Hill, North Carolina, September 2015.
- **Net Metering Updates**.
  Panel presentation at Solar Power International, Anaheim, California, September 2015.
- **The 50 States of Solar: Trends in Net Metering Policies and Rate Design.**
  Poster presentation at Solar Power International, Anaheim, California, September 2015.
- **Net Metering and Rate Design Trends**.
  Panel presentation at Intersolar North America, San Francisco, California, July 2015.

- **Distributed Disruption: The Economics and Policy Behind the Distributed Solar PV Boom**. Invited by Prof. Sanya Carley to give lecture to graduate energy economics class at Indiana University School of Public and Environmental Affairs, Bloomington, Indiana, April 2015.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at Grand Valley State University's Michigan Alternative and Renewable Energy Center, Muskegon, Michigan, May 5, 2015.
- **The Water Short List: The Most Effective Actions to Reduce Household Water Consumption**
  Poster presentation at the International School on Energy Systems, Seeon, Germany, September 2014.
- **More Than a Drop in the Bucket: How U.S. Households Can Reduce Water Consumption by 70%**
  Presentation at the 13th Annual Association for SPEA Ph.D. Students Conference, Bloomington, IN, March, 2013.

AWARDS & HONORS

- 2012 Top GPA Award, M.S. in Environmental Science
- 2012 Top GPA Award, Masters in Public Affairs
- 2011 SPEA Merit Award
- 2006 Liberal Arts and Management Program Writing Excellence Award
- 2005-2009 Indiana University Honors Recognition Scholarship

VOLUNTEER SERVICE

Citizens Action Coalition, Indiana, February 2019 – present
Board Member

Solar Power International, 2014 – 2016
Education Committee Member for the largest solar conference in America

SPEA, Prof. Evan Ringquist Research Team, Bloomington, Indiana, 2011
Volunteer Researcher on Environmental Justice Research Project

The Nature Conservancy, Indianapolis, Indiana, 2010
Volunteer Researcher on Economic Development and Community Green Space

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REGULATORY ASSISTANCE PROJECT

NOVEMBER 2020

Demand Charges: What Are They Good For?

An Examination of Cost Causation

Mark LeBel and Frederick Weston, with contributions from Ronny Sandoval

Contents

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The analysis in this paper rests on the shoulders of earlier RAP publications, in particular:

Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Linvill, C., Lazar, J., Dupuy, M., Shipley, J., & Brutkoski, D. (2017). *Smart non-residential rate design*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

Weston, F. (2000). *Charging for distribution utility services: Issues in rate design*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/

That said, responsibility for the information and views set out herein lies entirely with the authors.

Executive Summary

Demand charges, rates that are applied to an individual customer's maximum short-term usage (typically 15, 30 or 60 minutes) in a billing period, have existed since nearly the beginning of the electric industry. While utilities often favor demand charges, economists have continually questioned whether they are an efficient form of pricing. With the widespread adoption of advanced metering, this is an opportune time to reconsider demand charges, even for industrial customers, and replace them with more efficient time-varying energy (kilowatt-hour) rates.

Traditional monthly demand charges have always provided a perverse incentive that does not reflect cost causation for shared system costs. Individual customer noncoincident peaks (NCPs) do not reflect the coincident peaks that drive *shared* generation and delivery capacity costs. The price signal that demand charges send — to lower individual customer NCP and to level a customer's load over time — is substantially different than a price signal to reduce usage at the time of coincident peaks. As a result, demand charges penalize customers for usage at times that do not impose particularly high costs and encourage them to waste effort and money shifting loads off their own maximum hour (and sometimes onto high-load system hours).

The historic exception to this rule is a customer that has a nearly 100% coincidence factor with the relevant peaks. The prototypical example of this in the mid-20th century was an industrial customer with very high load factors. Demand charges could be reasonable in the past only as applied to this specific category of customers. But, in today's electric system, even this justification for demand charges falls away. High penetrations of nondispatchable but variable renewable generation means that a 100% load factor is unlikely to be, from a system perspective, the most desirable load shape. Rather, flexible load — load that can respond to swift changes in the availability of supply, perhaps in the middle of the day for solar and late at night with wind — becomes cheaper to serve than unvarying loads in systems marked by high penetrations of variable supply.

Historically, demand charges have frequently been sized to recover most or all shared system capacity costs. Again, this may have been reasonable enough in the mid-20th century for certain customers, but it does not reflect the economics and engineering of a modern electric system. The choices that system planners make are trade-offs between different types of costs. Much "capacity" investment today aims to reduce energy costs and is not incurred to meet peak reliability needs. This means that a significant portion of investment in generation, transmission and distribution plant (and the associated operation and maintenance expense) cannot be reasonably described as demand-related or driven by peak reliability needs. Any pricing structures that reflect the marginal costs of peak system capacity should be sized properly to reflect these distinctions. That includes

demand charges, if appropriate, as well as time-varying energy pricing.

It is fair to ask whether a properly sized "peak window" demand charge solves these issues. Although such a charge is superior to traditional demand charges for the pricing of shared capacity costs, peak window demand charges nonetheless retain many of the shortcomings of their traditional counterparts. Customers who have high usage at many times throughout the peak period should be charged more for capacity than customers who have a single high usage interval in that same window. Time-varying energy pricing provides superior incentives to optimize usage at all relevant times. Simple time-of-use rates are fairer and more efficient than peak window demand charges and can be made even more so by overlaying them with pricing that is responsive to critical peak conditions.

A few analysts and economists have identified several narrower applications where pricing structures akin to demand charges could be appropriate and reasonably efficient: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. While more research into these applications might be merited, demand-based pricing would only be a second-best approximation of a more efficient but potentially more administratively complex time- and location-based pricing system.

1. Introduction

Demand charges have existed almost since the beginning of the electric industry in the 1880s. They were originally called Hopkinson rates after John Hopkinson, a British engineer who described the concept in 1892. Hopkinson believed that costs of "plant and conductors"[1] — namely capacity costs — for an electric utility should be charged to customers based on the "greatest rate of supply the consumer will ever take."[2] Shortly thereafter, a meter was developed that could capture the highest kW power draw from the customer, defined over a period of an hour or half-hour, during an entire billing period (now typically a month). These rates became prevalent for industrial customers in the early 1900s.[3]

It did not take long, however, before economists called into question their putative cost-causation rationale. In 1941, future Nobel Prize winner in economics W. Arthur Lewis argued that the cost-causation case for demand charges was often based on "a simple confusion. … The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak."[4] In 1970, prior to becoming chairman of the New York Public Service Commission, Cornell University professor Alfred E. Kahn wrote that demand charges are "basically illogical."[5] More recently, University of California professor and California Independent System Operator board member Severin Borenstein opined that "it is unclear why demand charges still exist."[6]

Electric utilities and some consultants still make broad arguments for demand charges that are, at their core, the same as those made more than a century ago. In 2016, the Edison Electric Institute (EEI) asserted that "demand charges provide accurate price signals" and "better collect capacity costs [than other kinds of prices]."[7] EEI made this

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[1] Hopkinson, J. (1901). *Original papers: Vol. 1, Technical papers*, p. 257. Cambridge University Press.

[2] Hopkinson, 1901, p. 261.

[3] There was a debate within the electric utility industry about rate design in the 1890s. A time-of-use meter was invented nearly simultaneously with the demand meter, and some industry participants argued that time-of-use rates would be superior. See Hausman, W. J., & Neufeld, J. L. (1984). Time-of-day pricing in the U.S. electric power industry at the turn of the century. *The RAND Journal of Economics, 15*(1). This time-of-use meter disappeared from discussion relatively quickly, however, as an industry consensus formed around demand charges. Neufeld argues that demand charges were a part of utility strategy to discourage industrial customers from relying on distributed generation, known as "isolated plants" at the time. Neufeld, J. (1987, September). Price discrimination and the adoption of the electricity demand charge. *Journal of Economic History, 47*(3), 693-709. In addition, Samuel Insull, president of Chicago Edison (later Commonwealth Edison) and a major player in the industry, happened to own a part of the patent for the demand charge meter. See Yakubovich, V., Granovetter, M., & McGuire, P. (2005). Electric charges: The social construction of rate systems. *Theory and Society, 34,* 597-612.

[4] Lewis, W. A. (1941). The two-part tariff. *Economica, 8*(41), 252.

[5] Kahn, A. E. (1970). *The economics of regulation: Principles and institutions: Vol. 1, Economic principles*, p. 96. John Wiley & Sons.

[6] Borenstein, S. (2016). The economics of fixed price recovery. *The Electricity Journal, 29*(7), 10.

[7] Edison Electric Institute. (2016, February). *Primer on rate design for residential distributed generation,* p. 6. https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf

argument simultaneously for two different types of demand charges: (1) the traditional monthly noncoincident peak (NCP)[8] demand charge, based on an individual customer's NCP across an entire billing period, and (2) a peak window demand charge,[9] based on an individual customer NCP within a defined multihour interval, similar to the on-peak period for a time-of-use (TOU) rate.[10] In addition, there has been a push by EEI and many utilities to expand the application of demand charges beyond just the industrial and large commercial customer classes to small business and even residential customer classes.

Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general.[11] For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.

If there is a role for demand charges in today's electric system, it is much narrower than the one it performs for industrial customers in many jurisdictions. Modern versions of

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[8] A customer's noncoincident peak is its highest demand, in kilowatts, measured at the meter during the period in question. This customer demand can be measured based on different intervals, typically 15, 30 or 60 minutes. "Noncoincident" means that this demand does not necessarily occur at the time of a system peak.

[9] There is no standardized terminology for this type of demand charge where determination of the maximum demand for the billing period considers only a limited number of peak hours, similar to the peak period for a time-of-use rate. We find the "peak window demand charge" description more apt than the other alternatives.

[10] Less commonly, daily-as-used demand charges are part of the discussion, which we raise later in this paper. As the name implies, it is a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges. In this paper, we do not focus on contract (ex ante) demand charges, although they share many features with these other alternatives.

[11] There are other issues at play in the debate around demand charges, particularly whether residential and small business customers can understand and manage these types of rates and the related potential for inequitable bill impacts. See Chernick, P., Colgan, J., Gilliam, R., Jester, D., & LeBel, M. (2016). *Charge without a cause? Assessing electric utility demand charges on small consumers.* (Electricity rate design review paper No. 1). https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf; and Lazar J. (2015). Use great caution in design of residential demand charges. *Natural Gas & Electricity*. https://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf. The question of understandability of demand charges by residential and small business customers is a longstanding one. D. J. Bolton notes that a 1948 report by a government commission in Great Britain rejected demand charges for residential customers on two bases: (1) understanding of the rate and (2) the potential reaction to an overload encouraging higher usage levels going forward. Bolton, D. J. (1951). *Electrical engineering economics: Vol. 2, Costs and tariffs in electricity supply*, p. 255. (2nd ed. rev.). Chapman & Hall. We do not delve into these issues at length in this paper.

these charges need to be more rigorously fashioned to achieve economic efficiency and advance the public good than they have been historically. We examine three more nuanced cases where demand charges have been identified as a potentially efficient pricing mechanism: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. In these situations, pricing structures with some similarities to demand charges may be appropriate. In each of these cases, demand-based pricing would only be a second-best approximation of a more efficient time- and location-based pricing system.

Unless we reexamine fundamental ratemaking practices critically in light of the modern electric system and new technologies, we will miss major opportunities to optimize system costs, ensure reliability and improve societal outcomes. While utilities and some consultants have been pushing for new applications for demand charges, regulators and utilities should be moving in the opposite direction by replacing demand charges for industrial customers with more accurate pricing mechanisms.

2. Historic Cost-Causation Argument for Demand Charges

A frequently used but inaccurate cost-causation argument for demand charges begins with the observation that several of the most important cost categories can be denoted in kilowatts (kW) or megawatts (MW).

- Generation capacity is denominated in kW or MW, reflecting the maximum instantaneous power output of a given unit.
- Transformers are rated in kilovolt-ampere (kVA) or megavolt-ampere (MVA), a unit of apparent power[12] closely related to kW or MW.
- Conductors are rated in amps for the level of current that they can handle. For a given voltage, this leads to a maximum kW or MW power flow for that conductor (power equals current times voltage).[13]

From these engineering descriptions, which are accurate but potentially misleading, some analysts conclude that, because generation and delivery capacity can be measured in units of power (kW or MW), their costs are demand-related. Making the leap to retail rate design then becomes easy: Capacity costs are rated in kW, so prices should be reflected

[12] Apparent power is the combination of active and reactive power in an alternating current circuit that needs to be supplied to serve load. This includes the power components that are needed to energize the circuit but don't transfer useful power to the load.

[13] For three-phase power, power is current times voltage times the square root of 3.

in kW.[14] This is the essence of the argument made by EEI, but it rests on several fallacies.

Some earlier writers, including W. Arthur Lewis, D. J. Bolton and James Bonbright, are open to demand charges to a certain extent but are quite candid about their limitations and significant downsides. Important factors in this more nuanced determination include:

- The diversity and coincidence factors[15] of any group of customers who might face a demand charge.
- The relative metering costs for flat kilowatt-hour (kWh) rates, demand rates and time-varying rates.
- The ability (or lack thereof) for customers to economically shift certain types of load.
- The broad similarity of capacity and fuel costs for many generation alternatives (typically thermal steam units) prior to 1960.

Lewis acknowledged the metering problem in his 1941 article, "The Two-Part Tariff." He stated that "the two-part tariff [a demand charge and an energy charge] is superior to having a single undifferentiated price which discourages off-peak consumption, *but inferior to charging different prices at different times*, though it may sometimes be more convenient than the latter if the measurement and timing of consumption are costly."[16] In the early and mid-20th century, only simple kWh metering was economic for small customers (that is, the system benefit from the response to time-differentiated pricing did not exceed the cost of the metering necessary to support it), while more sophisticated metering could be justified for industrial customers.

In 1951 Bolton noted, with some approval, that demand charges were much more common for industrial customers than residential.[17] He observed that residential customers' peaks are more random, that is to say more diverse (spread out in time) and less likely to be correlated with system peaks: "A metered demand system for such a [residential] consumer would mean making a high charge for payment at times when it was most unlikely to matter."[18] He opined that the load of many large industrial customers is not

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[14] It is worth noting that these "kW" demand measurements are actually measured in units of kilowatt-hours per hour and simplified to be presented as measures of kW demand.

[15] Diversity of demand for a utility reflects the temporal differences in usage among customers. Peak coincident demand at any level of the system is less than the sum of customers' individual peaks because of these temporal differences. The calculated "diversity factor" provides a quantitative measure of these differences; conversely, a "coincidence factor" measures the extent to which these individual peaks do line up. These concepts are defined and discussed further in Section 3.1.

[16] Lewis, 1941, pp. 255-256 (emphasis added). Even in 1941, Lewis thought that it was no longer the case that demand metering would be cheaper than time-based metering, with one alternative being simple timers and another being "ripple control," where a utility sends a high frequency signal to flip an equipment switch.

[17] Bolton, 1951, p. 255. Bolton's proposed ideal "scientific tariff" features a TOU rate and no demand charges, where the on-peak price recovers demand-related costs. See Bolton, 1951, pp. 249-250.

[18] Bolton, 1951, p. 255.

particularly susceptible to shaping, because it is "motive power" (i.e., motors to run large equipment), and the electricity costs represent a small fraction of overall costs for these firms.[19] This type of industrial customer has strong incentives, given a set amount of productive capacity, to have the highest operating factor possible and thus a high load factor.[20] This industrial load pattern implies a significant likelihood that an individual customer's peak in a given month or year is closely linked to the customer's demand at the time of system peak.

Bonbright, writing originally in 1961, stated that traditional demand charges provide some benefits from "a tendency of existing customers to spread their loads over a longer period in order to minimize their demand charges, instead of bunching them during short period likely to coincide with the heavy loads of other customers."[21] Bonbright then went on to observe that electric rate design in those days "[was] far from ideal, and practical rate makers will do well to consider seriously its alleged infirmities viewed from the standpoint of its critics among the academic economists." He noted in particular that there was little sense in "the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof."[22]

Up until 1960, most generation options, with the exception of hydroelectric power, had very similar cost characteristics. Steam generation was the predominant capacity type, and there were few differences in cost among coal, oil and natural gas units. Even fuel prices were broadly similar. In such a system, there is a better case that all capacity is similarly situated to serve peak reliability needs and thus can be considered demand-related. As discussed later, this issue goes to the sizing of any demand charges if they can be shown to be a reasonable solution (in limited circumstances at best).

This combination of factors — (1) an industrial customer base with a relatively small number of customers, most of whom had high load factors, high peak-coincidence factors and high levels of consumption and (2) a large number of residential customers with lower coincidence factors and relatively low consumption per customer — provided a rough rationale for the rate designs that prevailed throughout most of the United States in the 20th century and are now lingering into the 21st. In pricing, this typically manifested itself in significant demand charges for large industrial classes to recover nearly all capacity costs and in fully volumetric energy rates for residential and small business customers.

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[19] Bolton, 1951, p. 238.

[20] Load factor is the ratio of an end user's actual energy usage in a period to its maximum potential usage in that period. It is calculated as follows: kWh/(peak demand x total hours), within the specified period.

[21] Bonbright, J. (1961). *Principles of public utility rates*, p. 311. Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

[22] Bonbright, 1961, p. 316.

In this historical context, this could be relatively fair and efficient for a narrow slice of customers that meet the relevant description. To the extent that other customers that could share capacity (e.g., churches and schools; offices and movie theaters) were faced with demand charges, these customers were treated unfairly and often paid significantly more costs than they caused.

3. Why Demand Charges Are Inefficient

Some of these arguments for demand charges held sway in the past, even though the better case for time-varying energy charges was well understood. Today, the features of the modern electric system undermine even the more nuanced historic case for demand charges altogether. This is true for large industrial customers as well as for residential and small business customers.

The original advocates of demand charges often focused on what they thought was a fair and efficient division of historic accounting costs. Modern economists, even those who still advocate for demand charges, recognize that this older perspective is in error and argue (correctly) that rate structures should be designed to efficiently optimize *future* costs.[23] This perspective leads one to the conclusion that rates should be reflective of forward-looking marginal costs. In utility regulation, this concept is translated into different operative regulatory language in different jurisdictions, calling variously for rates that discourage wasteful usage, reflect actual costs or ensure the causer pays those costs. But in each case, the underlying microeconomic principle is the same: Rate design should ensure that the actions customers take to minimize their own bills are consistent with the actions they would take to minimize system costs. The nitty-gritty of designing rates in this framework is how to fairly and efficiently reflect marginal costs in prices. The best way to conceptualize this is to examine how the customer responds to a given rate design — both its form and its magnitude. An efficient rate design will lead to customer behavior that optimizes system costs.

The marginal consumption incentives for customers in any system of time-varying rates are fairly straightforward: (1) discourage usage in periods of relatively high rates and (2) encourage usage in periods of relatively low rates. Prices that achieve these outcomes are charged in a way that is both (1) consistent (all kWh at a given time or system condition are treated the same) and (2) symmetric: If an increase in consumption causes a bill to rise by $10, then the same sized decrease causes a bill to decline by $10.

The incentives presented by a typical demand charge structure are somewhat more

[23] See, for example, Boiteux, M. (1960). Peak-load pricing. *The Journal of Business, 33*(2), 157-179. (H. W. Izzzard, Trans.); Kahn, 1970; and Crew, M. A., & Kleindorfer, P. R. (1979). *Public utility economics.* St. Martin's Press.

complex.[24] If a customer is perfectly flexible (indifferent as to when they take electricity from the grid) and has perfect foresight, a demand charge would clearly incentivize a 100% load factor within the relevant time frame (e.g., each month). Of course, such customers do not exist in the real world,[25] although there are some customers that come close to having 100% load factors because of the nature of their operations: 24-hour supermarkets, data centers and certain types of factories.

Because customers do not have perfect foresight and infinite flexibility, it is only possible to talk about the incentives created by a demand charge at a certain level of generality. The most obvious features of a demand charge are that it directly (1) discourages higher individual customer NCP demand and (2) encourages levelization of load within the relevant time period. The related key feature of all types of demand charges is that they act as a ratchet, even if the ratchet is not applied across multiple billing periods.[26] Once a certain level of demand has been reached, customers then face a *lower* marginal cost for the remainder of the period to which the demand charge applies, as long as they have a power draw between zero and their previous individual demand peaks.

When the demand charge impacts a particular consumption decision, it can be quite punitive — imagine paying $5 to $10 to make toast for a family, which is exactly what can happen with a poorly designed residential demand charge.[27] This shows up as a high marginal cost for a subset of hours and consumption decisions. But otherwise, if a particular consumption decision does not pose a substantial risk of setting the demand charge, then consumption becomes cheaper — defined solely by the other charges without any demand charge implications. This means that optimal customer decision-making under a demand charge is quite complex and depends on the level of foresight and the value of consumption across all of the relevant time periods. Of course, most customer decision-making will not necessarily be optimal but rather based on rules of thumb, particularly for residential and smaller commercial customers.

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[24] Sandford Berg and Andreas Savvides did some theoretical work that incorporated the granular incentives of a demand charge into a traditional economic model of consumption. See Berg, S. V., & Savvides, A. (1983, October). The theory of maximum kW demand charges for electricity. *Energy Economics (5)*4, 258-66. However, this was a two-period model with numerous simplifying assumptions. Such a simplified theoretical model does illuminate certain features of a demand charge, but the authors note numerous areas for further work. To our knowledge, this line of theoretical research has not been pursued.

[25] This is true in particular because customer "utility" from electricity is not solely about the amount of consumption. Customers also enjoy significant convenience benefits for certain usage timing, again assuming that on-site storage and energy management are not cheap and convenient enough to smooth these features out.

[26] Some rates that do not meet this criterion are occasionally described as demand charges, such as annual system coincident peak capacity charges. These types of charges may, however, be better thought of as a type of time-varying rate or perhaps in a third category of their own.

[27] A toaster is approximately 1 kW demand; see Home Energy Saver & Score: Engineering Documentation. (n.d.). *Default energy consumption of MELs*. http://hes-documentation.lbl.gov/calculation-methodology/calculation-of-energy-consumption/major-appliances/miscellaneous-equipment-energy-consumption/default-energy-consumption-of-mels. If a customer uses it for 15 minutes straight at the time of the customer's individual peak, the monthly demand billing determinant increases by 1 kW with a corresponding bill increase.

As the analysis in the subsections that follow shows, demand charges — whether of the traditional monthly variety or the peak window variety — are inefficient and inequitable for the pricing of shared system costs, as is the continued reliance on them. There are three interrelated reasons for this:

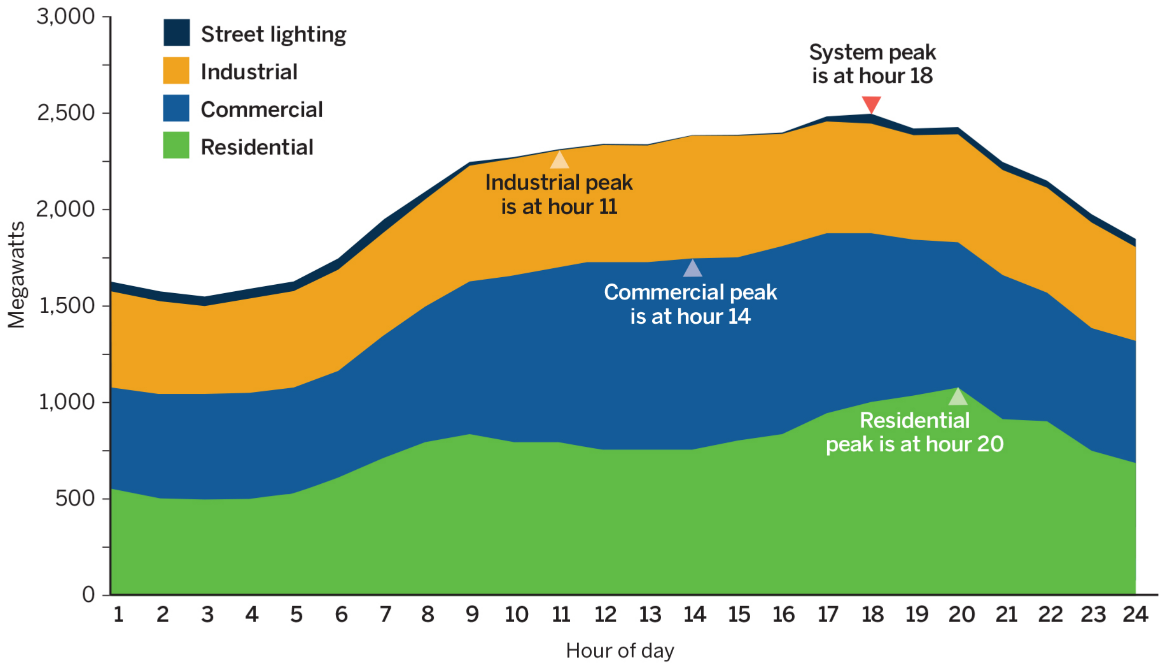
1. Traditional monthly demand charges provide an inaccurate price signal that is unrelated to high-cost periods for nearly all customers and which leads to inefficient customer efforts and investments in response to its incentives. The changes in the electric system due to dramatic increase in wind and solar generation mean that, from a system perspective, very high industrial load factors are not necessarily optimal.
2. Even in cases where a traditional demand charge could be justified, the sizing of demand charges to recover nearly all generation and delivery capacity costs reflects an outdated perspective of the engineering and economics of the electric system. Modern cost allocation and rate design must reflect the trade-offs between different types of expenses and investments. Much capacity investment is designed to reduce energy costs and line losses and should be charged on that basis.
3. Although a reasonably sized peak window demand charge is superior to a traditional monthly demand charge, time-of-use and other kinds of time-varying rates remain more efficient and equitable. These time-varying rate options are enabled by the dramatic decrease in the cost of sophisticated metering over the past two decades.

3.1 Individual Peaks Are Not the Same as System Peaks

Virtually all of the electric system consists of capacity that is shared among customers. With the exception of facilities that serve one or a very few customers, each component of the system is sized to meet an expected peak coincident demand of the customers it serves. The costs incurred to meet peak coincident demand, both short-run variable costs and capacity investment, are a significant portion of overall system costs. As a matter of economic efficiency, it is crucial that prices reflect the marginal costs of meeting the coincident system peak. Peak coincident demand is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as *diversity* of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might, or might not, coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads, through a shared transmission network. Figure 1 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

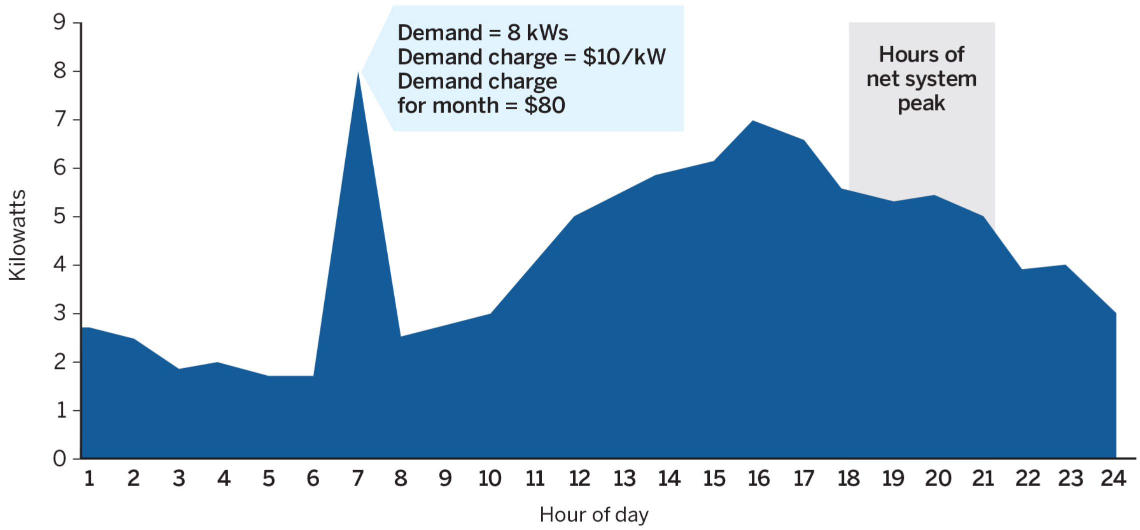
Figure 1. Diversity at the customer class level



Diversity can be quantified as the ratio of the sum of the subgroup peaks to the relevant coincident peak — the diversity factor. In this illustrative example, the diversity factor of the customer classes is 1.1. Diversity factors cannot go below 1 because in the extreme case where all subgroups peak at the same time, the sum of the subgroups equals the overall coincident peak. As long as customers peak at different times, diversity factors are higher as you consider smaller subgroups. Load diversity across individual customers is even greater than across customer classes.

Traditional monthly demand charges impose a rate on each customer that is independent of the system peak, as illustrated in Figure 2 on the next page. These demand charges provide little, if any, incentive to minimize a customer's contribution to system peak, unless a strong correlation exists between the customer's peak and the system's, a circumstance known as a high coincidence factor. In this illustrative example, a residential customer has an electric water heater that runs for nearly a full hour in the morning and a substantial cooling load in the afternoon.

Figure 2. Illustrative monthly noncoincident peak demand charge for an individual residential customer



Demand charges encourage customers to flatten their own load curves relative to their individual maximum usage but do not necessarily encourage them to consume energy in ways that optimize system costs. If we assume that Figure 2 shows customer usage before a traditional monthly demand charge is imposed, we could expect significant changes in usage after application of this charge. It would be reasonable to expect this customer to attempt to reduce the 8 kW demand reached at 7 a.m. In the case of an electric water heater, the individuals living in the house could change their behavior or adjust the settings on the water heater. If the customer could reduce that morning peak, then there would be some incentive to reduce the afternoon peak caused predominantly by cooling load. In this case, the customer would benefit by moving some portion of that load away from hour 16 to other hours, including possibly during the system peak from hours 18 to 21. Furthermore, this customer could increase overall kWh consumption since the marginal cost would be lower at times (often including the system peak) when there is little risk of triggering a higher demand charge.

More generally, a flat individual customer load shape may not, in fact, be what is best for the system and is in fact worse than a low load factor with predominantly off-peak usage. The clearest illustration of this is street lighting load, which, for most systems, falls entirely outside the system peak hours and has a roughly 50% load factor. If we designed and sized a demand charge for street lighting on the same basis as a typical demand charge for industrial customers, it would force this low-cost off-peak load to pay as much for system capacity as an industrial customer using the same amount of power during the peak periods. This is virtually never done, however, and street lighting is treated as a separate rate class without any demand charges.

D. J. Bolton summarized the basic problem facing utilities and regulators in the middle of the 20th century:

> The aim should always be the improvement of the *system* load factor, and the only justification for an elaborate tariff is that it shall contribute directly to this end. … If these costs are passed on to the consumer as they stand, in the form of a two-part [maximum demand] tariff, the fixed charge will be levied on the consumer's individual [maximum demand] instead of his effective demand on the system. The consequence will be that low-load-factor consumers will be overcharged (since they are given insufficient credit for their greater diversity) whilst the high-load-factor consumers are under-charged.
>
> The weakness of such a tariff when applied to the small individual consumer is that it treats load factor as a variable and diversity factor as a constant. … But, in practice, diversity factors vary from consumer to consumer almost as much as load factors, and moreover, in the opposite direction.[28]

In other words, diverse customers can efficiently *share* capacity, and rate design should recognize this fact. As Bolton mentioned, it is often the case that small users have *lower* load factors but more diversity and thus less impact on peak. This is still true today because many small residential users have lower levels of heating and cooling usage (smaller residences) and often have similar appliances (microwaves, toasters, dishwashers and dryers) that are used more sporadically than larger residential customers. This means that the load factor for each individual appliance is lower, but the power characteristics are similar for each usage of an appliance.

As described in Section 2, demand charges may present a rough price signal to control peak system demand for customers with a high system-peak coincidence factor. In that case, controlling a customer's individual peak does systematically reduce the overall coincident peak. One case where this could be true historically is large industrial customer classes, where individual customer usage is driven by large equipment that is constantly used throughout every working day of the year. Even for this type of customer, however, there remains the question of whether load can be shifted from peak hours to off-peak hours. A critical peak energy price would produce a superior price signal, to actively reduce usage at critical peak hours, rather than maintain steady usage at those hours if such a shift is possible. Indeed, industrial customers in Texas, faced with significant, narrowly focused transmission charges based on four coincident peak hours, use specialized consultants to help them identify, in advance, the hours to which those

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[28] Bolton, 1951, p. 107-108 (emphasis in original). Bolton was writing at a time when, in operations, customer demand was taken largely as a given and much of the resource mix was dispatchable thermal generation. In those circumstances, improvement of system load factor would, all else again being equal including overall kWh consumption, lead to a reduction in total system costs.

charges will be applied and reduce usage sharply in those hours.[29]

For a diverse customer class, however, the share of customers who face this demand charge price signal at system peak times is random and inconsistent. In almost any hour, whether near system peak or the lowest-load hours of the year, some customers will face the demand charge price signal. Also, a substantial number and, at times, a majority of customers (e.g., those customers who have already hit their peaks in the billing period) face a lower marginal cost at system peak times. While this is very blunt and inaccurate, it could be a sharper price signal than a traditional flat kWh rate in some circumstances, although a customer's likelihood of facing those circumstances would vary randomly. In contrast, a well-designed TOU rate provides the broadly correct incentive for all marginal consumption choices by all customers, sending a consistent price signal for on-peak and off-peak periods; a critical peak pricing rate can be even more precise, focusing on specific hours when the electric system is under stress.[30]

The undesirable effects of demand charges are made worse by ratchets across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. For example, billing demand may be the greater of this month's noncoincident maximum load and 80% of maximum in the previous 12 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to system peak, there remains little incentive to minimize usage at a time of system peak.

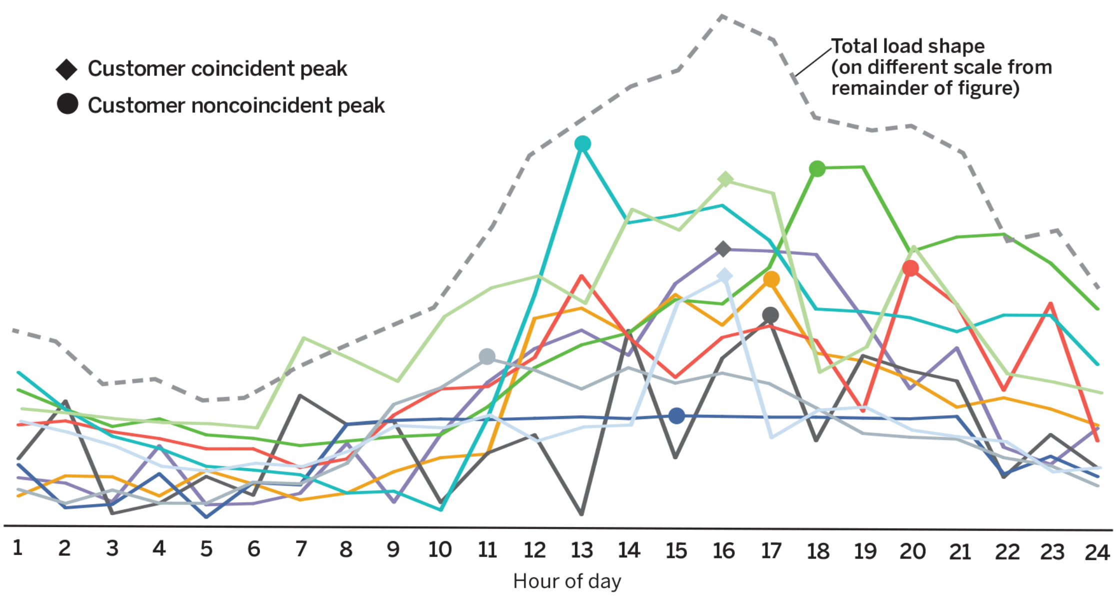
It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. Even at this level, there can be significant diversity among customers sharing a single transformer.

[29] Zarnikau, J., & Thal, D. (2013, September). The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market. *Utilities Policy, 26*, 1-6.

[30] To be more precise, we should say a "relevant component of the system" since different components of the system may hit peaks at different times. It's not unusual to see a systemwide peak occur at a particular hour on a particular day, but for individual elements of the subtransmission and distribution systems to hit peaks at other times. Expressing these peaks in prices and capturing each user's causal relationship to them is a challenge of time-varying rate design and, to the extent that this reflects different peaks in different areas of the system, may require locational distinctions as well. Precision is valuable, but complexity may produce inferior customer response.

Figure 3 shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. The total load shape is on a different scale than the individual customer loads.

Figure 3. Summer peak day load from 10 residential customers on one line transformer

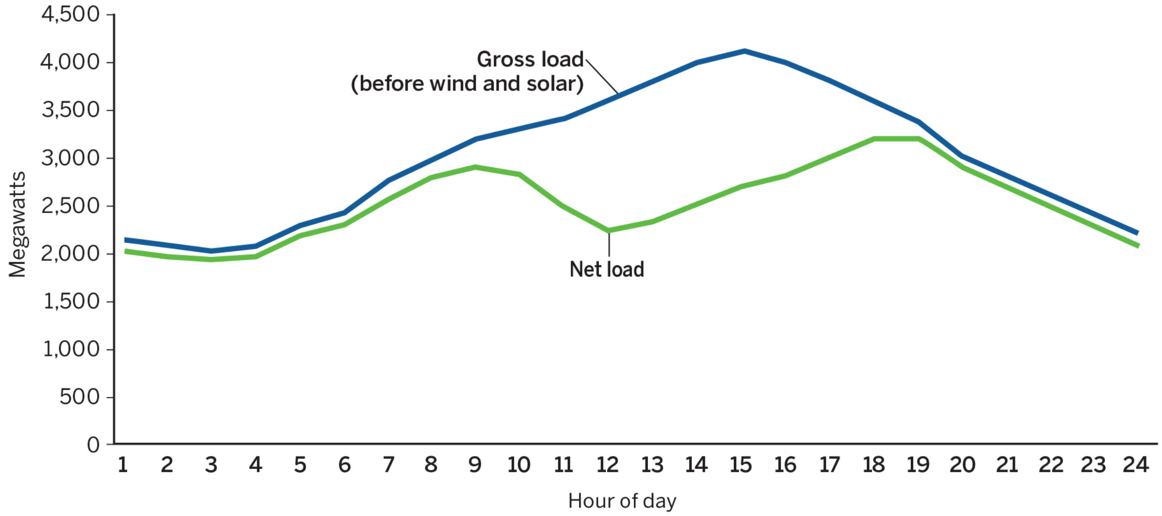


Source: Confidential load research sample

This demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day, which translates into a diversity factor of 1.16. This is just the variation on a particular high-load day. Although not shown in this figure, this coincident peak is only 64% of the sum of the annual NCPs for the individual customers, which translates into a diversity factor of 1.56.

At least two features of the modern electric system are changing the traditional argument that high-load-factor industrial customers should be subject to demand charges. First, the timing of traditional peaks and valleys, and by extension their effect on both short-run variable costs and longer-term capacity needs, is changing due to the increased prevalence of variable renewable resources. In regions where solar generation has increased rapidly, the “duck” curve is now a familiar phenomenon, as shown in Figure 4. Second, relatively low-cost on-site energy storage means that *all customers* have the potential for economically shiftable load and can respond to time-based price signals.

Figure 4. Illustrative net load curve



In such a situation, the benefits of shifting energy intensive industrial load from early evening to midday could be quite large. But this could mean *an increase* in the customer load factor, which is substantially discouraged by demand charges.

3.2 A Significant Portion of Capacity Investment Is Not Demand-Related

Traditional cost allocation terminology makes a distinction among demand-related, energy-related and customer-related costs. This terminology may obscure more than it illuminates. In particular, the term "demand-related" is often used to imply that demand charges are a proper pricing method for recovering costs so designated. Moreover, "demand-related" has typically referred to system peak demand and not individual customer peaks.[31] Other terminology, such as "peak-related," is more descriptive of the concept and avoids confusion with the use of "demand" in other contexts (such as "demand for energy").

[31] See Bolton, 1951, p. 132 (describing demand-related costs as "a cost proportional to system demand") and pp. 143-144 (describing how to spread costs across a wide number of potential system peak hours). In rate design, these same costs might be recovered through demand charges for certain customer classes. When determining the rate in dollars per kW, the total costs are then divided over the larger denominator of individual NCP demand, without accounting for load diversity within the class. This reduces the dollars per kW as charged to each customer from the dollars per kW used to assign costs to each class. This reduction is labeled differently in different jurisdictions, such as an "effective demand factor." However, this reduction is passed through to all customers and does not correct for differences in the timing of individual customer peaks. Customers who have demand highest at peak times receive a discount, and those who have demand highest at other times are overcharged.

Advocates for demand charges sometimes assert that most or all capacity costs are demand-related, which maximizes the size of the demand charge (if one is at all justified).[32] This leads to the large magnitude of the demand charges for industrial customer classes in many states. However, significant portions of capacity costs are not demand-related but are in fact incurred to meet energy needs. Investments in generation, transmission and distribution in the modern electric system may serve either of the two primary objectives of system planners, but the degree to which demand plays a role in each objective is different. These two goals are: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. In many respects, reliability concerns arise predominantly at peak system hours.[33] Meeting system load at least cost, by its very nature, must consider usage patterns across every hour of the year. To meet these two objectives, system planning, investment and operation must jointly consider not only the engineering and physics of the electric system but also the economics of the relevant choices. We see this tension in the evolving landscape of capacity resources.

With respect to generation, most capacity costs may have been demand-related prior to the invention of the modern combustion turbine in the 1960s. In an electric system dominated by largely homogenous steam generation capacity, a MW of capacity built for peak demand could be used equivalently year-round.[34] In such a situation, generation capacity costs could be allocated and charged predominantly at peak times.

The existence of multiple different types of generation capacity, storage and demand response changes this analysis significantly.[35] Aggregate supply (generation, storage and demand response) must be sufficient for systemwide coincident peaks, as well as contingencies across many other hours of the year, such as when outages (unforced and even planned, such as nuclear refueling) combine with other circumstances (e.g., unusual weather) to push demand up against the limit of available resources.

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32 See Faruqui, A., & Davis, W. (2016, July). Curating the future of residential rate design. *Electricity Daily*, 23. http://files.brattle.com/files/7137_curating_the_future_of_rate_design_for_residential_customers.pdf. The authors state that "a large share of a utility's costs are actually driven by investment in infrastructure, such as generation capacity and transmission and distribution (T&D) networks. These costs are not directly related to the amount of energy that is consumed; they are, instead, driven by various measures of maximum electricity demand." See also the description of an idealized rate design that "recover[s] capacity costs through demand charges" in Faruqui, A. (2019, June 1). 2040: A pricing odyssey. *Public Utilities Fortnightly*, p. 56.

33 Reliability can be thought of as having two dimensions, in terms of both system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

34 Even this historic scenario is a substantial oversimplification due to significant level of hydro generation in many areas.

35 Bonbright recognized this briefly in a footnote; see Bonbright, 1961, 354, fn 15. By 1970, this was a better understood and less theoretical concept so that Kahn spent multiple pages discussing it; see Kahn, 1970, pp. 97-98. M. A. Crew and P. R. Kleindorfer formalized mathematical models of optimal pricing with multiple different types of generation capacity; see Crew & Kleindorfer, 1979.

The optimal mix of resource types depends on the broader load patterns. Different generation technologies have different capabilities and different cost characteristics and should not be blindly lumped together as "capacity" for cost allocation and rate design purposes. The kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the kind of capacity that one would build to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period) is proving much cheaper than building *any* kind of generation resource that is seldom used. In order to be economic, capacity that serves only short-term needs must have low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon.

So there is a trade-off between capacity costs and energy costs. Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework.[36] Under any reasonable version of the demand-related classification, it is important to recognize that the capacity costs placed here are to serve relatively short-period peak reliability needs.

Even the appropriate short-period peak reliability capacity costs should be charged on a broader basis than the absolute peak hour of the year for several reasons. One is that, while planners and operators generally have a good idea of when a system peak is likely to occur, they by no means know for sure. Consequently, there is a reliability value to capacity in many hours that should be reflected in prices.[37] A second is that the actual peak can be influenced by pricing structures. For example, if a system peak could be reliably predicted for the 5 p.m. hour on a given day, charging a higher price at that single hour could just push that same peak to 4 p.m. without a meaningful reduction. This is the "whack-a-mole" problem. Taking both of these issues into account, some writers have referred to the relevant set of peak hours as the "potential peak" period.[38] This is a major consideration in the determination of on-peak hours for a TOU rate or a peak

[36] See Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.) (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[37] The operating reserves demand curve mechanism in the ERCOT wholesale market is one means of establishing that value across the entire year. In many areas, the loss of load probability is relatively high for only 50-100 hours per year, which is the typical design criteria for critical peak pricing and demand response programs.

[38] Bolton, 1951, p. 143.

window demand charge. A related challenge is that different elements of the system (e.g., generation, transmission and distribution) may peak at different times, which should be accounted for to the extent possible.

Generation capacity also has some reliability value in off-peak hours. Generation reliability issues may come primarily at peak times but certainly not exclusively. This can be because of generator outages (both planned and unplanned), unusual weather, transmission outages, other operating constraints or a combination of the above. D. J. Bolton commented in 1951 that there had been several times that load needed to be shed in off-peak seasons because of generator maintenance, which was "a definite indication of demand-related expenses on account of generating plant" even in off-peak seasons.[39] A loss-of-energy-expectation study calculates the year-round generation reliability risks and is one of the best ways to allocate demand-related generation capacity costs (but not energy-related generation capacity costs) over the entire year.[40] A probability-of-dispatch method, alternatively, assigns the total costs of generation resources to the hours in which each resource provides service.

Many of these same considerations apply to the transmission and distribution system, and an analyst should look to the underlying purposes and benefits of system investments to allocate and charge them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. The transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In many situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy and should be classified on that basis. Last, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year.

Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering options for transmission and distribution networks that have implications with respect to line losses, another clear energy-related benefit.[41] There are generally two types of losses incurred across the transmission and distribution system: no-load losses and load losses. No-load losses are incurred primarily to energize transformers (both station transformers

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[39] Bolton, 1951, p. 143.

[40] Lazar et al., 2020, p. 132.

[41] See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

and line transformers). Smaller transformers consume less energy in this respect, but overloaded transformers incur high load-related losses, so optimal transformer sizing saves energy.

The system planning considerations for load losses, also known as resistive losses, are more complex. These losses occur as electrical current flows through each element of the system. These losses manifest themselves in the form of heat and reduce the amount of useful power that can supply customer loads. This relationship is represented by the formula:

Load losses (in kW) = $I^2 \times R$

Where I = current (in amps) and R = resistance (in ohms)

Load losses can be decreased by reducing the resistance or reducing the current. Installing conductors with thicker metal wires is a simple way to reduce resistance, but these larger conductors are more expensive. Investments that reduce the current can, however, be much more effective because losses go up with the square of current. Any investment that reduces the current by 50% will reduce load losses by 75%, and any investment that reduces the current by 90% will reduce load losses by 99%. Since the current required to supply load is highest during peak demand periods, system losses are greatest during peak demand periods. There are several different types of capacity investments that reduce current substantially:

- **Higher voltage lines:** There is a direct relationship between the voltage of a line, the current passing through the line and the power delivered.
    - Current (in amps) = power (in kW)/voltage (in volts)
    - As a result, increasing the voltage by a factor of 10 reduces the current by 90%, which in turn reduces load losses by 99%.
- **Siting substations closer to loads:** By siting substations closer to loads, one can reduce the losses incurred by having conductors at lower voltages supply loads across long distances — the latter condition resulting in higher currents and relatively higher losses.
- **Converting single-phase distribution lines to three-phase power:** Three-phase power requires one additional conductor and additional space for the arrangement of the lines. For three phase lines, current = power/(voltage x $\sqrt{3}$). At the same voltage, current drops by 42.3% and load losses are reduced by two-thirds.
- **Distribution level control of voltage and reactive power:** Capacitor banks, smart PV inverters, voltage regulators and other more distributed assets across the system can compensate for voltage and reactive power needs at a local level that would

otherwise need to be met through the supply of upstream resources delivered through the grid — the latter condition resulting in higher currents and greater incurred losses.

- **Optimizing the location and size of line transformers:** Siting transformers closer to customers allows for shorter secondary lines that have low voltage and thus higher losses per foot. For some areas, this may require additional transformers, which comes at a cost. Smaller transformers also have lower no-load losses. Unfortunately, smaller transformers have lower rated capacities and thus higher load losses for a given level of current. Conversely, larger transformers have higher no-load losses but lower load losses. These complex economics should be analyzed to account for trade-offs between capital costs and energy losses. Modern advanced metering infrastructure (AMI) systems provide the ability to prepare heat maps on each transformer, enabling optimal sizing to minimize costs and losses.[42]

All of these factors should be accounted for in both cost allocation and rate design. Energy-related benefits from transmission and distribution capital investments are quite extensive. In a relevant sense, nearly all transmission lines are built with a substantial purpose of minimizing line losses for the delivery of large volumes of energy. Choice of the voltage level for a transmission line, either for a new line or upgrading an old line, involves higher capital costs for higher voltages with the counteracting benefit of lower losses. These costs are energy-related costs, not capacity-related costs. Furthermore, many of these energy benefits from investments to minimize line losses are not static over the course of the year. They increase dramatically at times of system peak because current delivered over the system is much higher, and marginal system losses at the time of peak can be 15-20% in many utility systems.[43] In addition, these benefits can be compounding because they are not limited to fuel costs or wholesale purchases. A more efficient transmission and distribution system can lower generation capacity requirements as well, including reserves.

All of these economic and engineering phenomena should be properly reflected in any analyses of cost causation. More specifically, these distinctions must be passed into rate design or else it gives rise to opportunities for customers to take inappropriate advantage by gaming the rates, with bill savings that far exceed any long-term reduction in system costs. The experience of the British Central Electricity Generating Board, a wholesale provider, provides a stark example of this in the late 1960s. The central board charged the regional boards for generation capacity costs based solely on a narrow peak window. In response, the regional area boards built their own combustion turbines at significantly lower cost to generate during these peak hours. This forced the central board to change its

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[42] See Lazar, J. (2018, October 18). *Smart grid and community benefits — with no rate increase? How Burbank made it happen.* Regulatory Assistance Project. https://www.raponline.org/blog/smart-grid-and-community-benefits-with-no-rate-increase-how-burbank-made-it-happen/

[43] Lazar & Baldwin, 2011, p. 4.

wholesale rates, charging for only marginal capacity costs in a short peak and charging for the bulk of capacity costs in a broader period.[44] The key insight in this scenario is that demand-related costs charged to peak times should only reflect the marginal costs of relatively cheap generation, storage or demand response capacity costs incurred for short-period peak reliability purposes.

Modern examples of this pricing problem can be found in the current practices of several independent system operators and generation and transmission suppliers. For example, ERCOT currently charges on the basis of the highest hour in each of the four summer months for recovery of embedded transmission system costs to distribution service providers. This type of pricing mechanism is inappropriate for transmission costs and furthermore distorts the operation of the wholesale energy markets by over-incentivizing a wide range of customer actions.[45] Similarly, many electric cooperatives, charged by their generation and transmission suppliers on the basis of NCP demand imposed on the wholesale supplier, have installed water heater control systems to mitigate this demand at much lower cost than the avoided demand charges. Since the generation and transmission demand charges include the cost of baseload units and transmission, they greatly overstate the value of localized NCP load reductions. While these are wholesale examples, the same economic proposition also extends to retail rates.

3.3 Time-Varying Energy Rates Are More Efficient Than Peak Window Demand Charges

Once one acknowledges the time-dependent nature of cost in the generation and delivery of electricity to end users on a shared system, one must necessarily acknowledge the superiority (as matters of economic efficiency and fairness) of prices that reveal to those end users that temporal variability in cost to those that do not. The question, then, is simple: What should those prices look like? In some sense, a peak window demand charge does recognize this time dependency. However, a comparison of the incentives presented by time-varying demand charges and time-varying kWh charges reveals why time-varying kWh charges are the better approach.

There are several types of time-varying energy rates to be considered today.[46] Key design choices for these rates include the number of time periods, whether the price for each time period is set long in advance or can itself vary based on system conditions and market

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[44] Kahn, 1970, pp. 97-98.

[45] See Hogan, W., & Pope, S. (2017, May). *Priorities for the evolution of an energy-only electricity market design in ERCOT*, pp. 69-79. Harvard University and FTI Consulting. https://hepg.hks.harvard.edu/publications/priorities-evolution-energy-only-electricity-market-design-ercot-0. We do not endorse the proposed solution of Hogan and Pope but agree with the transmission pricing problem that they describe.

[46] From this definition we exclude seasonal rates and kWh prices that vary from billing period to billing period. These kinds of rates can also reflect the cost-causation basis of rates but provide little or no incentive to manage usage within a billing period.

outcomes, and the actual prices for each time period.[47] The simplest is known as a time-of-use or time-of-day rate, which utilizes a small number of preset time periods and prices within each billing period. The most sophisticated time-varying rates are typically described as real-time prices, which are updated at short, regular intervals (e.g., hourly) based on prices in wholesale energy markets.

There are also options that combined preset time periods with pricing that varies based on system conditions in a predictable manner. With critical peak pricing, or the related peak-time rebate alternative, higher prices for times when the grid is stressed are set well in advance, but the days (and perhaps the hours) where these higher prices apply are actively chosen in response to system conditions. Variable peak pricing, as currently offered by Oklahoma Gas & Electric,[48] adds another layer of price differentiation by allowing more preset options for the on-peak price period. The on-peak price depends on market conditions: low, standard, high and critical. This choice between four different alternative on-peak prices allows for a higher level of precision in marginal incentives. All of these variations share a common goal — to improve the load shape for a utility by decreasing peak period load and shifting some of that to off-peak periods.

In this context, it is most natural to compare peak window demand charges with simple TOU rates because many of the key parameters can be kept constant. For both of these options, the peak time periods and the prices charged are set well in advance and can be set to recover the same categories of costs. Holding those two variables constant, peak window demand charges are inferior to time-varying kWh charges in that same peak window, as a general method for charging peak capacity costs, for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

Peak window demand charges can certainly elicit customer response and incentivize them

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[47] The options that are available in practice depend on metering technology, which has evolved substantially over time. In the early part of the 20th century, TOU rates could be implemented with meters that operated on timers, where one track would record on-peak usage every day and another track would record off-peak usage every day. No distinction based on weekends or holidays was possible. By 1941, more sophisticated versions were available with remote controls that could switch the meters between tracks on command. Since that time, many more innovations have occurred to enable different types of time-varying rates. Three-period TOU rates became common for large industrial customers in France beginning in the 1950s. With advanced metering infrastructure and a sophisticated data collection and billing system, the possibilities are nearly endless. Even without AMI, simple TOU meters have long been available that track on-peak and off-peak usage based on programmed timers, which can exclude weekends and holidays from on-peak periods.

[48] Oklahoma Gas & Electric. (2018, June 18). *Standard pricing schedule: R-VPP variable peak pricing.* https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

to shift load from inside to outside that window.[49] Nevertheless, peak window demand charges share many of the faults of traditional monthly demand charges, just on a different scale. Once again, the key distinction is between the consistent and symmetric marginal incentive of a time-varying kWh rate and the arbitrary effects driven by the demand charge's ratchet.

A close examination of customer behavior reveals why energy-based prices are preferable to demand charges even within a peak window. In any system with significant customer diversity, a large number of customers will not have their individual peaks at the time of the system's peak. Still, it could be that a substantial number of customers peak at the time of the system peak. The proportion of one to the other matters if demand charges are to have a significant linkage to the system peak. Customers who are at risk of setting the individual peak for the demand charge face a high marginal price for consumption, but those who are not face a lower marginal price. This proportion will vary from service territory to service territory and over time as technology evolves.

Customer behavior under a peak window demand charge would likely even vary based on completely arbitrary factors. That could be whether certain customers are at the beginning of their billing period or whether a significant event that led a customer to incur a largely unavoidable peak (e.g., hosting a party during a peak window) happened before that very high-load time. This randomness can be entirely avoided. The fair and efficient solution is to continue to treat all consumption as marginal, a condition that is achieved by time-varying kWh rates.

In the absence of technology that automates response to changes in prices, the ratchet problem for peak window demand charges may be diminished by the inability of customers to respond accurately to its incentive structure. It is unlikely that people going about their daily lives can do more than respond to the broad incentives provided by either an on-peak kWh price in a simple TOU rate or a peak-window demand charge. In both cases, the easiest answer may very well be just "consume less during the peak window period."[50] This could mitigate the harm posed by the ratchet, but it also begs the question about the underlying rationale if there is no customer response.

A modest subset of residential customers may be able to respond to the next rule of thumb presented by a peak window demand charge: to operate as few end uses as possible simultaneously. Fully responding to the incentives posed by a demand charge requires

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[49] See, for example, Stokke, A., Doorman, G., & Ericson, T. (2009). *An analysis of a demand charge electricity grid tariff in the residential sector.* (Discussion Paper No. 574). Statistics Norway, Research Department. https://ideas.repec.org/p/ssb/dispap/574.html

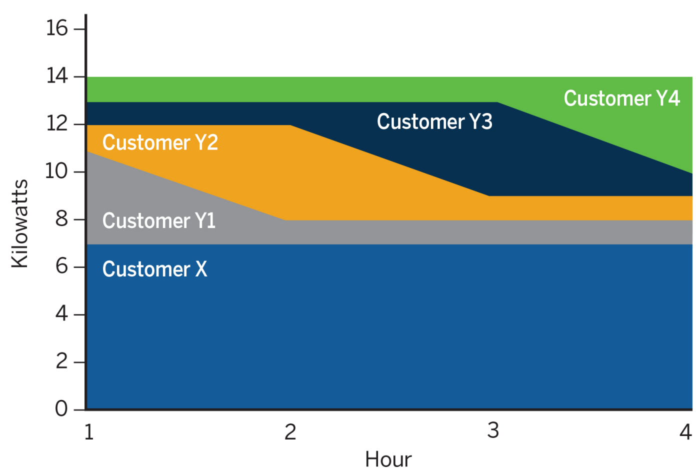
[50] For example, the Mid-Carolina Electric Cooperative has a three-hour peak window demand charge for residential customers. On the relevant page of its website, the peak window demand charge is labeled as an "on-peak charge." None of the advice given to manage this rate is specific to the actual working of a demand charge and could equally apply to a three-hour on-peak kWh rate. Mid-Carolina Electric Cooperative. (n.d.). *Rate structure.* http://www.mcecoop.com/content/rate-structure

customers to track their demand and know whether they are currently at risk of setting a high demand for the billing period — too much to ask of many residential and small business customers.

However, energy management technology, enabled by software and "supercharged" by on-site storage, will be able to adjust usage in a far more responsive manner than ordinary people could manage alone. Such energy management is likely feasible today for larger customers and could very well be widely feasible for smaller customers in the next few years. At least one company, Energy Sentry (http://energysentry.com/index.php), has developed a residential "demand controller" that automatically sheds less critical loads (water heaters, clothes dryers) when priority loads (microwaves, coffee makers, hair dryers) are activated. Such technology would allow customers to respond more effectively — *from their perspective* — to the incentives provided by a demand charge. But that is not to say that the overall efficiency of the electric system will be improved, since customer responses to demand charges do not typically optimize use of the system.

Peak window demand charges also create intraclass cost allocation problems, which are linked closely to the above efficiency concerns. Peak window demand charges still overcharge the low-load-factor customer and undercharge the high-load-factor customer. This is illustrated in the case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Such a hypothetical is shown in Figure 5 for a four-hour peak period.

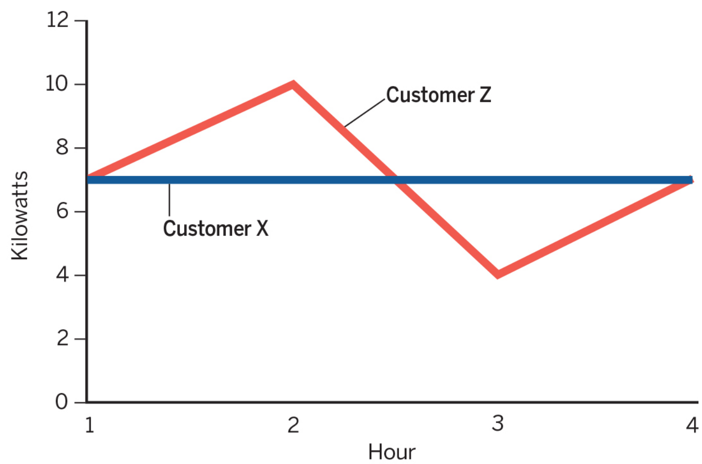
Figure 5. Customer load comparison illustrating ability to share capacity



Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as Customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, Customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that Customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Time-varying energy-based charges solve this problem.

Peak window demand charges, though an improvement on monthly NCP demand charges, still come up short in the effort to send accurate information to consumers about peaks and other high-cost events. The occurrence of a peak cannot be known in advance, and, indeed, its timing depends in part on price structure. Shifting hours within a peak period does not necessarily lower the overall peak. Figure 6 is a comparison of two customers with equal kWh consumption in the peak period, one with a flat consumption throughout that period and another that varies.

Figure 6. Comparison of two customers



Compared with Customer X with a flat load pattern, Customer Z with the varying load pattern likely increases the chance of a system peak in hour 2, but by the same token likely decreases the chance of a system peak in hour 3. But the reverse can be said for Customer X compared with Customer Z: Customer X raises the likelihood of a system peak in hour 3 and decreases the likelihood of a system peak in hour 2. Advocates of demand charges consistently fail to explain why these types of discrepancies are justified by cost considerations.

Even well-designed TOU rates do not necessarily reflect critical peak times very well. For example, a four-hour weekday on-peak window for only the highest demand months will include around 200-400 hours annually. These will necessarily contain some days with higher peaks than others and only a limited number of hours that define utility capacity needs for reliability purposes at peak. Simple TOU rates do not distinguish in this regard between the moderate peaks (e.g., ordinary days in the summer) and the very highest peaks (e.g., extremely hot days in the summer). In short, the implication is that simple TOU rates do not provide a sharp enough incentive on actual peak days.[51] In any case, we are no longer bound to simple TOU pricing. Dynamic rates, including critical peak pricing, peak-time rebates, variable peak pricing and real-time pricing, all better address peaking issues because they provide higher marginal prices at the times of maximum system stress. By concentrating customer attention on the hours that actually drive costs, the more dynamic rates produce better results for the electric system and society.

By its very nature, a demand charge cannot present symmetric and consistent marginal incentives in the same way as a time-varying kWh charge. Compared to traditional demand charges, properly sized peak window demand charges have a better cost causation

51 This is referred to as the needle-peaking problem in Crew & Kleindorfer, 1979, p. 186.

basis because they can be linked to the time periods that drive higher system costs. Daily as-used demand charges[52] applied to peak windows could be a further improvement on peak window demand charges, and, better yet, these peak window daily-as-used demand charges could fluctuate according to system conditions. However, this is only an improvement because it converges on the better solution, a system of time-varying kWh rates. Given the rate design possibilities that AMI offers, what reason is there to retain demand charges at all?

4. What Might Be Left for Demand Charges?

The foregoing demonstrates that the typical argument for demand charges, as used for generation, transmission and shared distribution capacity, is substantially flawed. Even so, we want to investigate if there are any circumstances, however limited, for which demand charges are an efficient rate design.

Some theorists have identified a different and, in our minds, much narrower set of rationales for demand charges. The case for time-varying rates relies substantially on the diversity of load and the lack of a direct relationship between individual customer peaks and the system peaks that drive costs. A diverse set of customers may, in the aggregate, create a predictable load profile much of the time. But what if this diversity goes away in an unpredictable manner? Or, for that matter, in a predictable one? Is there something about the causation of costs in special and *limited* circumstances that warrants charging for peak incurrences of short-term (e.g., 15-minute) demand for individual customers? To answer this question, we consider three cases that, on their faces, might present a marginal-cost justification for demand charges. The first is one that we have carved out from the beginning: capacity costs that are not shared, such as dedicated transformers and service drops, which we term "dedicated site infrastructure."[53] This illustrates some important issues relevant to any broader theoretical case for demand charges. The second is the cost associated with uncertainty in customer behavior. The third is timer peaks, a phenomenon where customers shift usage in response to hours with lower prices.

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52 RAP authors, writing with partners from Synapse Energy Economics, previously recommended daily-as-used demand charges for standby service to large combined heat and power customers, as an alternative to monthly standby demand charges. The purpose was to recognize that different combined heat and power customers would have scheduled and forced outages on different days and could share the same capacity to provide their standby service. This was certainly an improvement on monthly demand charges for such customers, but, in light of the progress made in metering and time-varying energy-based rate structures, there's every reason to think today that such time-varying energy rates are equally appropriate to customers with on-site generation. Johnston, L., Takahashi, K., Weston, F., and Murray, C. (2005, December 1). *Rate structures for customers with onsite generation: Practice and innovation*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy06osti/39142.pdf

53 RAP has previously recommended a small transformer or site infrastructure demand charge for secondary voltage customers, particularly those customers with dedicated site infrastructure. See Lazar, J., & Gonzalez, W. (2015, July). *Smart rate design for a smart future*, pp. 53-54. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

4.1 Dedicated Site Infrastructure

Dedicated transformers and service drops for individual customers are, by definition, not shared infrastructure. The relative importance of this category of cost will vary by customer class. Larger commercial and industrial customer classes, as long as they are taking secondary voltage service, will often have dedicated transformers for each customer or a dedicated transformer bank for customers taking three-phase power. Dedicated transformers will be rare for residential customers in urban and suburban areas, but single-family homes will almost always have a dedicated service drop. The largest industrial customers may have their own primary line (effectively serving as a dedicated service drop) or a dedicated substation (effectively serving as a dedicated transformer). In rural areas, each customer will typically have a dedicated transformer, at which point transformers are customer-specific site infrastructure.

For these customer-specific site infrastructure costs, there is no diversity of demand between the customer meter and point of connection with the shared system. As a result, individual customer NCPs are certainly relevant to the sizing of these components. One might conclude from this that a demand charge can provide a reasonable pricing incentive here. The time period for such a demand charge should have nothing to do with a shared peak since there is no sharing of the infrastructure. Nor should it be limited to peak windows since the peak for an individual customer could occur at any time. The cost of these components may be no more than about $1/kW/month, a fraction of typical demand charges.[54]

There are also other ways of efficiently pricing this category of costs. A similar set of customer incentives may be presented by a connected load charge for a set amount of local capacity. Such a connected load charge can help with efficient sizing, but only if it's accompanied by a fee for overages or the automatic tripping of circuits when demand would cause an overage. Even then, a connected load charge provides no incentive for customers to manage their usage efficiently; that is, there are no cost savings to be gained by keeping their demand below the level of the predetermined connected load. A charge that establishes the relationship of the customer's individual peak demand to the sizing of these components might, however, give the customer some incentive to minimize peaks.

It is worth examining this issue at the level of engineering and planning. What type of customer behavior would minimize the risk of transformer overload and degradation? Or what type of customer behavior would allow utilities to size dedicated transformers more efficiently?

Capacity ratings for the different elements of the electric system are set with many

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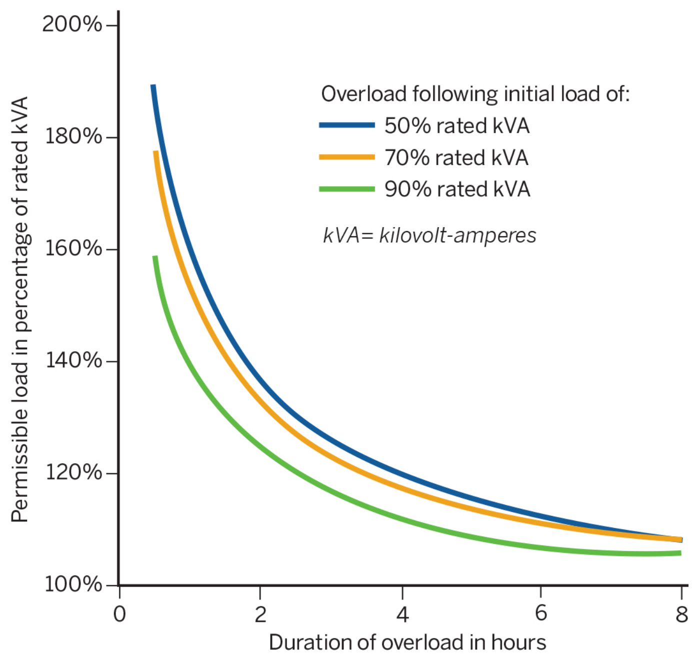
[54] Seattle City Light, for example, has a large general service rate with specific charges for transformer investment; these are $0.27/kW/month. Seattle City Light. (n.d.). *City Light rates.* https://www.seattle.gov/light/rates/summary.asp

engineering limits in mind. Many of the most important considerations revolve around the heating — and overheating — of components, particularly transformers and conductors. This has a number of different implications. For example, effective delivery capacity can be higher in the winter than the summer or higher in the cool nighttime than during the sunny daytime. The capacity ratings for individual system elements are for sustained loads in typical conditions, but loadings can exceed those ratings on a regular basis without necessarily incurring significant damage. As Tom Short colorfully puts it, a conductor rated 480 amps "will not burst into flames at 481 [amps]."[55]

Figure 7. Permissible transformer overloads for varying periods



Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

Figure 7[56] demonstrates the maximum overload that a transformer can take without shortening its operating life, by examining two primary variables: (1) the initial load prior to any overload and (2) the duration of an overload. If a transformer has had light loads (50% of its rating), it can sustain a short-term overload of nearly 190% or a four-hour overload of just over 120%.

The important question then is what kind of rate design incentivizes optimal customer behavior with respect to this equipment. Panagiotis Andrianesis and Michael C. Caramanis have developed an algorithm for dynamic nodal locational marginal costs for distribution systems that offers an intriguing approach to pricing for these customer-specific facilities. For line transformers, the pricing formula is a real-time price per unit of energy that follows the transformer thermal response dynamics, which is essentially the temperature of the cooling oil in each transformer.[57] Similarly, a critical peak energy charge could apply for the few hours per year when a transformer is

[55] Short, T. A. (2004). *Electric power distribution handbook*, Section 3.5, p. 140. CRC Press.

[56] Bureau of Reclamation. (1991). *Permissible loading of oil-immersed transformers and regulators.* https://www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf

[57] Andrianesis, P., & Caramanis, M. (2019). *Distribution network marginal costs: Part 1, A novel AC OPF including transformer degradation.* arXiv. https://arxiv.org/abs/1906.01570

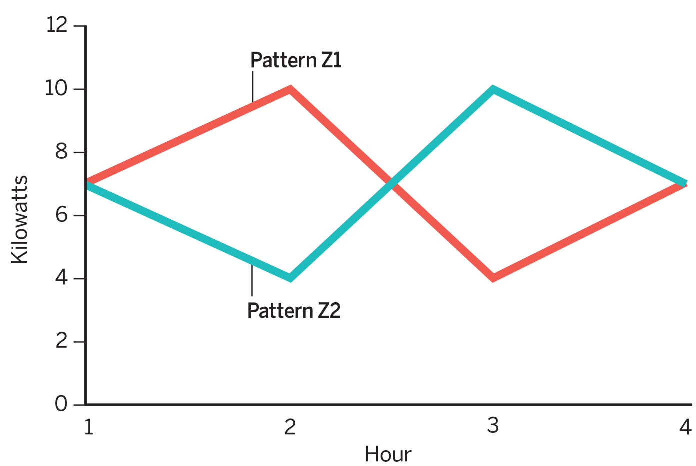
stressed but would require real-time monitoring and pricing to be applied on a transformer-by-transformer basis.

This type of short-run marginal cost pricing does not resemble a demand charge and has the virtue of linking closely in time the incurrence of high marginal costs to the prices charged. These approaches are quite sophisticated and could be costly to administer. To achieve a rate that is more feasible now, a simpler structure would be necessary. A daily-as-used demand charge or a traditional monthly demand charge, based on 15-minute or 30-minute peaks, could certainly discourage the extremely high short-term peaks that would damage a transformer. Those options might not do enough, however, to discourage a sustained, multihour overload.

4.2 Risks of Customer Variance at Peak Times

Load diversity isn't static and can fluctuate in ways that are both predictable and unpredictable. Predictable changes often occur around the weather, one of the few variables that simultaneously affects all customers in a given area. Regarding unpredictable changes, consider a simple hypothetical illustrated in Figure 8.

Figure 8. Two hypothetical load patterns randomly chosen by customers



If there are 10 "random-load" customers who flip a fair coin to determine whether their load profile corresponds to either Z1 (heads) or Z2 (tails) in Figure 8, the average load in each hour across a large number of trials will be 70 kWh.[58] However, system planning must not only deal with the expected average load but rather the chances of higher load. Unfortunately, in any given trial of this scenario, the probability of five heads and five tails — leading to a demand of 70 kW in every hour — is only 24.6%. There is a small but nonzero chance that every customer gets either heads or

[58] In this illustrative example, we consider each customer to have a flat load within each hour. This means that kW and kWh are largely interchangeable as units. Similar examples could, however, be constructed with demand varying in smaller increments (e.g., 30, 15 or 5 minutes), and similar results could be obtained.

tails, leading to a 0.2% probability of a peak load of 100 kW. The full spectrum of potential results for this hypothetical scenario with 10 random-load customers is shown in Table 1.

Table 1. Peak load and probabilities for 10 random-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Peak load (kWs)	Probability
10 heads or 10 tails	10	0	100	0.2%
9 heads or 9 tails	9	1	94	2.0%
8 heads or 8 tails	8	2	88	8.8%
7 heads or 7 tails	7	3	82	23.4%
6 heads or 6 tails	6	4	76	41.0%
5 heads and 5 tails	5	5	70	24.6%

The cumulative odds of a peak of 88 kWh or higher is 10.9%, and a peak of 82 kWh or higher is 34.4%. In this hypothetical scenario, it is clearly beneficial to have customers flatten their load curves to 7 kW every hour within this time period. Table 2 shows the range of possible results and associated probabilities for six random-load customers corresponding to either pattern Z1 or Z2 and four flat-load customers with a demand of 7 kW in each hour.

Table 2. Peak load and probabilities for six random-load and four flat-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Flat load: Number of customers	Peak load (kWs)	Probability
6 heads or 6 tails	6	0	4	88	3.1%
5 heads or 5 tails	5	1	4	82	18.8%
4 heads or 4 tails	4	2	4	76	46.9%
3 heads and 3 tails	3	3	4	70	31.3%

The risk of a peak of 88 kW or higher drops from 10.9% to 3.1%, and the risk of a peak of 82 kW or higher drops from 34.4% to 21.9%. If the customer choices are uncorrelated, this type of risk goes down as the number of customers increases.[59] However, if the customer choices are correlated, between hour 2 and hour 3 in this hypothetical, the risk does not necessarily decrease with a higher number of customers.

[59] The ratio of the variance to the expected total decreases in proportion to the square root of the number of customers.

This simple example is the essence of the argument made by Michael Veall.[60] He demonstrates that, for a given level of average customer demand during a peak, higher variance customers lead to a risk of higher peaks, particularly if they are correlated. This, in turn, results in a need for higher capacity planning margins. Veall constructs a detailed economic model of optimal peak period pricing. He states that the traditional monthly demand charge does not reasonably address this issue, but rather a peak window demand charge can serve as marginal price on a customer's variance. He notes additional caveats: "If there are many small users with uncorrelated demands, the effects of an individual user's variation on total system variation will be small. But if users are large or their demands are correlated, variance charges are important."[61] Finally, Veall's result demonstrates that, if a peak window demand charge is to be imposed, it should be paired with an on-peak kWh rate.[62] The logic around risk and Veall's theoretical model present an argument for a peak window demand charge that is substantially different from those that utilities put forward. And again, we see a more defensible justification for peak window demand charges for larger-volume customers. But the key question of correlations and *levels of risk* has been neglected in the discussion around demand charges and is only a theoretical possibility in Veall's model. Furthermore, Veall's model does not consider the possibility of more granularly dynamic time-varying kWh rates.

Marcel Boiteux, the influential French economist and executive for Électricité de France (EdF), does discuss risk and uncertainty in a 1952 paper, written jointly with his colleague Paul Stasi.[63] When it comes time for tariff design, Boiteux and Stasi describe two different zones of the shared electric system: (1) the "collective network" and (2) the "semi-individual network, whose capacity depends particularly on the uncertainties of consumption of each customer."[64] With respect to the collective network, they find that the "uncertainties of individual consumption" are small enough to be ignored.[65] And, finally, their analysis of the "semi-individual network" is dominated by risk and the irregularities of individual customer's loads. This leads them to a justification for a complex system of subscription-based contract demand charges, with higher prices for contracted demand in

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[60] Veall, M. (1983). Industrial electricity demand and the Hopkinson rate: An application of the extreme value distribution. *The Bell Journal of Economics, 14*(2), 427-440.

[61] Veall, 1983, p. 429.

[62] Veall, 1983, p. 431. Veall notes that this on-peak kWh price could, in principle, even be negative, which would be a curious result.

[63] Boiteux, M., & Stasi, P. (1964). The determination of cost of expansion of an interconnected system of production and distribution of electricity. In J. Nelson (Ed. & Trans.). *Marginal cost pricing in practice.* Prentice Hall. (Original work published in 1952).

[64] Boiteux & Stasi, 1964, p. 117.

[65] Boiteux & Stasi, 1964, p. 117

peak periods and lower prices in other periods. However, Boiteux and Stasi offer little but generalities as to the demarcation of the semi-individual network:

> The extent of the zone within which the uncertainties of individual demands have a very marked influence on the collective cost is greater in proportion to the irregularity of the demands considered, and to the correlations among these demands. This extent depends also on the density of consumption, for the number of customers supplied from a given node plays an important role in the "reduction of uncertainties."[66]

Based on these considerations, Boiteux and Stasi largely describe the generation and transmission system (150-220 kV) as the "collective network" and the distribution system (15-60 kV) as the "semi-individual" network.[67] They are discussing these issues in the context of the then-new Tarif Vert for high voltage industrial customers, and the discussion could be read in a manner that is limited to those customers. This could mean that the dividing line for the semi-individual network could vary by the size of customer. Whether residential customer fluctuations are correlated in a significant and pertinent way is another empirical question Boiteux and Stasi do not address. It is unclear whether the irregularities of individual residential customers would ever be significant enough to matter at a level higher than a shared transformer.

4.3 Timer Peaks

Michael A. Crew and Paul R. Kleindorfer (1979) raise another area where a demand charge could theoretically be efficient, which they describe as the secondary preferences of customers, given the structure of time-varying rates, and the shifting of demand to notionally off-peak times. This is colloquially known as a timer peak. This occurs if customers increase their usage substantially during hours with low rates or more specifically right at the time when low-priced hours begin.[68] In the worst-case scenario, TOU rates can theoretically just shift the system peak without reducing it if enough usage is shifted to hours with low prices. The same is true of coincident peak window demand charges. This outcome can be avoided by managing the number of periods in the rate, the hours covered by each period and the relative prices. One utility has designed a TOU rate in which each customer chooses a three-hour peak period of 4-7 p.m., 5-8 p.m. or 6-9 p.m. All of these customers have 6-7 p.m. in their peak period; two-thirds of them have 5-6 p.m. and 7-8 p.m. in their peak period; and one-third have either 4-5 p.m. or 8-9 p.m. in their

66 Boiteux & Stasi, 1964, p. 123

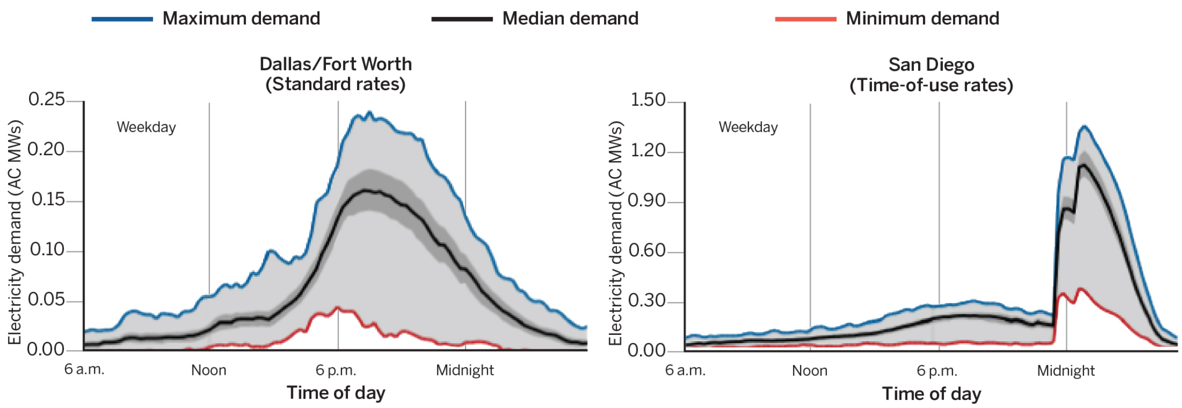
67 Boiteux & Stasi, 1964, p. 110.

68 Bonbright mentions this as a possible objection to time-of-use rates. See Bonbright, 1961, p. 362, fn 23: "In Chapter 10 of his book already cited in footnote 10, Davidson suggests this type of rate [time of day and time of season] as preferable to the familiar Hopkinson-type rate. But among the objections to it is the danger that its sharp breaks will create surges in the loads imposed on a power station or on a distribution line."

peak period. This provides the utilities with the most powerful pricing signal during the most likely peak hour but substantial peak reduction in the adjacent hours.[69] Another simple solution is to apply different hours to different classes or subclasses. For example, single-family residences may have their tariff shifted one hour earlier than apartments, or secondary general service one hour later than primary general service.

If the more general system peaks are not impacted significantly enough by this phenomenon to warrant changing the structure of the rate, more granular and local issues can theoretically arise. Figure 9 shows a set of results from a San Diego Gas and Electric rate for electric vehicles, where the "super off-peak" rate begins at midnight.[70]

Figure 9. Real-world illustration of timer peak with EV charging on TOU rate



Source: Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the Electric Vehicle Market*

This is a rational customer response to a TOU rate, at least for specific end uses. If an electric vehicle is parked at home in the evening and will not be used again until morning, then the customer has a significant amount of flexibility to choose when charging will begin. The very beginning of the lowest price period is an obvious time to start charging. While this may not present an issue at the generation and transmission level, assuming midnight remains an off-peak period, bunching of EV charging could lead to issues at the more local level.

Again, thinking about a line transformer helps focus the analysis. If five single-family homes are served by one shared transformer and all five of those homes have EVs that start charging at midnight, then impacts at the line transformer level are a possibility. Furthermore, what if those houses have other timed usage that starts at the beginning of the lowest price period? Sending a secondary price signal that discourages households

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[69] Salt River Project. (n.d.). *SRP EZ-3 price plan.* https://www.srpnet.com/prices/home/ez3.aspx

[70] Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the electric vehicle market*, p. 16. M.J. Bradley & Associates. https://www.mjbradley.com/sites/default/files/MJBA_Accelerating_the_Electric_Vehicle_Market_FINAL.pdf

from turning on all of their major end uses at midnight could be effective. A daily-as-used demand charge can send such a signal if it were applied across 24-hour periods. A more traditional monthly demand charge, however, will send that signal in a much more attenuated way. A connected load charge based on a contract demand for the cost of connection, with fees for overages, similar to the Électricité de France Tempo rate for residential customers,[71] would send a similar price signal as well.

There are other ways to deal with this phenomenon besides price signals with demand-charge features. The beginning of the off-peak period with the lowest price could be staggered for different customers, for example, beginning at 10 p.m. for one-third of customers, midnight for another third and 2 a.m. for the last third. For customers with long-duration controlled loads, like water heaters or electric vehicles, this would be easy for the customer to manage and beneficial to the utility. To maximize the benefits of such an approach, one would need to have a relatively even split among those three options for the customers on each shared transformer. Load management programs and smart devices could deal with this type of issue as well. For some loads, particularly water heating and EV charging, we anticipate advanced devices that will enable the utility to manage loads to minimize costs and enable customers to benefit from even lower off-peak rates for enabled devices.

One could even question how much of a problem this poses to the longevity of the shared transformers in question. The ambient temperature has almost always cooled off by midnight, and several hours of low or moderate loads could allow the transformer to cool from significant levels of usage during the day or early evening. In certain circumstances, it could be more convenient and cost-effective to upgrade any potentially affected transformers, particularly where multiple water heaters or EV chargers are served from a single transformer.

5. Conclusion

Demand charges, of either the traditional monthly NCP or peak window variety, are not efficient, as a general matter, for shared system capacity costs because:

- For the vast majority of customers, any peak reduction signal in a traditional monthly demand charge is weak and inaccurate.
- Traditional calculations for demand charges have included far too many costs as demand-related. Ideally, utility commissions will adopt a new time-based classification

[71] Electricite de France. (n.d.). *Tarif Bleu: Regulated sale tariff for electricity*. https://particulier.edf.fr/en/home/energy-and-services/electricity/tarif-bleu.html

and allocation framework for generation, transmission and shared distribution costs.[72] Failing that, the numerous energy benefits from capacity investments should be properly accounted for — that is, reflected in energy, not demand, charges.

- Simple TOU rates are superior to peak window demand charges in their own right, but AMI enables time-varying energy charges, such as critical peak pricing, peak-time rebates and variable peak pricing, that much more accurately target times of system stress and reward end users for shifting their loads to off-peak times.

Although we have shown the significant downsides to using current forms of demand charges, in very limited circumstances there might be cost- and efficiency-related justifications for certain types of demand charges. But such charges would be significantly lower than those prevailing for industrial customers in the United States today. Dedicated site infrastructure is a small portion of utility system costs, and typical demand charges would not necessarily provide an optimal signal to control these costs. The primary concerns around timer peaks are almost certainly limited to local infrastructure.

As for the general risk of customer variance and correlation, little work has been done to investigate the statistical bases of this more sophisticated case for demand charges. We think that it is unlikely that such an analysis would find that a substantial demand charge would be fairer or more efficient than time-varying energy charges. Lastly, there is a better case for demand charge-like structures for large customers, who are more likely to have significant dedicated site infrastructure. One might also argue that high variance at peak times among these customers has a more significant chance of influencing the overall system peak. Any such demand charges may not look like Hopkinson rates and would likely be only a second-best solution to a sophisticated system of time-varying energy charges.

The economic and regulatory principles that underlie these judgments are not new. The inescapable essentials of microeconomic theory are at work here. Boiteux, Bonbright and Kahn follow these principles and theories, as do the other scholars and practitioners we cite. In 1964, Paul Garfield and Wallace Lovejoy[73] also stepped into the fray. They converted principles of economic efficiency and fairness into straightforward criteria for assessing the merits of cost allocation methods and rate designs for generation and delivery capacity costs:

- All utility customers should contribute to capacity costs.
- The longer the period of time that customers preempt others' use of capacity, the more they should pay for the use of that capacity.

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[72] Lazar et al., 2020.

[73] Criteria adapted from Garfield, P., & Lovejoy, W. (1964). *Public utility economics,* pp. 163-165. Prentice Hall.

- Any service that makes exclusive use of a portion of capacity should be assigned all of the costs for that portion of capacity.
- The allocation of capacity costs should change gradually with changes in the pattern of usage.
- More capacity costs should be allocated to on-peak usage than off-peak.
- Interruptible service (or other forms of utility restrictions and control) should be allocated less in capacity costs as the degree of restriction increases.

Only time-varying energy charges can meet all of these objectives simultaneously. Demand charges for shared costs are demonstrably less efficient and less equitable than they.

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Exhibit BDI-3

State Net Metering Legacy Rights Policies

State	Transition Year from Net Metering to Modified Net Metering or Net Metering Successor	Legacy Period for Net Metering	Legacy Eligibility Deadline for Net Metering	Legacy Period for Net Metering Successor or Modified Net Metering
AR	TBD; not before 2023	20 years from date of Phase 3 Order (June 1, 2020)	Applies to customers submitting a signed Standard Interconnection Agreement to the utility by December 31, 2022	TBD
AZ	2017, or in rate case order issued thereafter	20 years from date of interconnection	Effective date of rate case decision establishing the applicable RCP rate (August 17, 2017 for APS)	10 years from date of application
CA	2017, or when utility reached 5.0% cap, for moving from "NEM 1.0" to "NEM 2.0"	20 years from interconnection year	Interconnection before July 1, /2017, or date when utility cap reached, whichever comes first	20 years from interconnection year
CT	2022+	20+ years (expires December 31, 2041)	December 31, 2021	TBD
HI	2015	Indefinite (lifetime of system)	October 12, 2015	NEM Successor export rates fixed through 2022
IA	Utilities may propose changes after July 1, 2027, or when the NEM cap is reached	20 years	Iowa Utilities Board Order adopting changes to compensation rate	20 years from time of operation
IL	TBD	Indefinite (lifetime of system)	TBD	TBD
IN	July 2022 at the latest	Up to 15-30 years (expires July 1, 2047 for all NEM customers enrolled by December 31, 2017; expires July 1, 2032 for NEM customers enrolled after 2017 through July 1, 2022)	System operating before July 1, 2022 (or earlier for utilities reaching net metering cap)	TBD
KS	Post-July 2014 NEM customers can be subjected to additional charges or alternative rate designs	15 years (Pre-July 2014 customers have a Legacy period through 2029 against reduced rate for monthly excess and additional charges)	System operating prior to July 1, 2014	N/A

State	Transition Year from Net Metering to Modified Net Metering or Net Metering Successor	Legacy Period for Net Metering	Legacy Eligibility Deadline for Net Metering	Legacy Period for Net Metering Successor or Modified Net Metering
KY	TBD. No sooner than in the final decision in the utility's first rate case filed on or after January 1, 2020.	25 years	Date of PSC Order approving changes in utility rate case to NEM or rate design	TBD
LA	2020	15 years (expires December 31, 2034)	Interconnection application and installation completed by December 31, 2019	None specified
MI	2017 (DTE) TBD (Consumers Energy pending rate case)	10 years	Based on final order date in utility's rate case establishing NEM successor tariff.	None specified
NH	2017	At least 23 years (expires December 31, 2040)	June 23, 2017	Up to 23 years (expires December 31, 2040)
NY	2022	Indefinite (lifetime of system)	January 1, 2022	20 years
SC	2021	Up to 10 years (Expires May 31, 2029 for all customers that enroll after May 16, 2019 through May 31, 2021; if enrolled before May 16, 2019, expires December 31, 2025)	Interconnection application filed on or before May 31, 2021	TBD
UT	2017	At least 18 years (expires in 2035)	September 29, 2017	Up to 15 years (expires 2032)

Exhibit BDI-4

Modified Net Metering ("NEM") and Net Metering Successor Policies

State	Compensation Mechanism	Transition Year from Net Metering to Modified Net Metering or Net Metering Successor	Compensation for Excess Generation	NEM Cap	System Size Restrictions
AR	NEM through at least December 31, 2022. TBD thereafter.	TBD; not before 2023	NEM: Monthly excess credited to customer's next bill at retail rate. SB 145 (2019) NEM/Net Billing: For non-demand rate customers, all exports credited at the utility's avoided cost rate plus an "additional sum" to be determined by the PSC, which may not exceed 40% of the avoided cost rate.	N/A	Residential: 25 kW Non-Residential: 1 MW (PSC discretion to increase to 20 MW)
AZ	Net Billing	2017 (e.g., APS), or in rate case order issued thereafter	Monetary credit for all exports during a month at the Resource Comparison Proxy (RCP) rate, set at less than the retail rate, to be succeeded eventually by a value of solar rate. Non-solar DG: NEM (not included in RCP decision). APS: NEM customers now only have access to certain rate structures, involving a time-of-use (TOU) rate (with $0.70/kW grid access charge) or several demand rates.	N/A	None (system may not exceed 125% of customer's total connected load)
CA	NEM "2.0" (i.e., NEM, excluding $/kWh non-bypassable charges (NBCs), and requiring service under a TOU rate)	2017, or when utility reached 5.0% cap	Exports to the grid credited at close to the retail rate. NEM 2.0 customers pay non-bypassable charges (~2-3 cents/kWh), levied based on gross consumption during the metered interval, with NBCs excluded from monthly carryover. The metered interval is 15 minutes for non-residential customers and 1 hour for residential customers for the purpose of NBCs. NEM 2.0 requires customer enrollment on a TOU rate.	NEM 1.0: 5% aggregated customer peak demand NEM 2.0: N/A (until NEM Successor Tariff adopted)	NEM 1.0: 1 MW generally NEM 2.0: No size cap

State	Compensation Mechanism	Transition Year from Net Metering to Modified Net Metering or Net Metering Successor	Compensation for Excess Generation	NEM Cap	System Size Restrictions
CT	NEM currently and under future “Netting Tariff” option.	2022+	NEM: Currently, monthly excess credited to the customer's next bill at the retail rate. HB 5006 (2019) provides for a transition to a system where the customer may choose net billing or a buy-all, sell-all arrangement. Under net billing the netting period may be zero (real-time), one day, a fraction of a day, or up to one month (i.e., monthly would be traditional NEM). In 2021, regulators ruled that monthly netting would continue to be offered under a future “Netting Tariff” option.	N/A	2 MW
HI	Options (1) Non-Export (2) Buy-All, Sell-All (3) Net Billing	2015	Net Billing Option: All exports compensated at time period differentiated rates, but no credit for exports that take place from 9AM-4PM. Excess kWh (not including any exports during the zero credit period) are banked to the following month.	15% per circuit distribution threshold	100 kW for IOUs
IA	NEM currently. Net Billing no earlier than 2027 or after cap is reached.	Utilities may petition after July 1, 2027, or when the NEM cap is reached	NEM: Monthly excess credited to customer's next bill at retail rate. Net billing or inflow/outflow crediting using a Value of Solar rate to be established after NEM 1.0 cap is reached, or through a proceeding initiated on or after July 1, 2027.	5% statewide DG penetration	1 MW
IL	NEM currently. Net Billing after utility NEM cap is reached.	TBD	NEM: Monthly excess credited to customer's next bill at retail rate (non-competitive rate classes) as a kWh credit. Net Billing: Hourly netting of imports and exports, with hourly exports compensated at supplier avoided cost or PPA rate.	5% of utility's peak demand in previous year	2 MW

State	Compensation Mechanism	Transition Year from Net Metering to Modified Net Metering or Net Metering Successor	Compensation for Excess Generation	NEM Cap	System Size Restrictions
IN	NEM currently. Net billing beginning July 1, 2022, or sooner if cap is reached.	July 2022 at the latest	NEM: Monthly excess credited to customer's next bill at retail rate as a kWh credit. Net billing: Compensation for excess generation equal to 1.25 multiplied by "the average marginal price of electricity paid by the electricity supplier during the most recent calendar year"	1.50% utility's summer peak load	1 MW
KS	NEM currently. *Mandatory demand charges on NEM customers was struck down by state supreme court in 2020. Grid Access Charge was rejected by regulators in 2021.*	Post-July 2014 NEM customers can be subjected to additional charges or alternative rate designs, but none currently apply.	Retail rate. (Monthly excess generation credited at he monthly average system cost of energy.)	1% of utility's retail peak demand during previous year	Residential: 15 kW (25 kW pre-July 2014) Non-residential: 100 kW (200 kW pre-July 2014) Schools: 150 kW
KY	NEM currently. 2021+: TBD	TBD. No sooner than in the final decision in the utility's first rate case filed on or after January 1, 2020.	TBD. Exports will be compensated at the "dollar value" specified by the PSC in utility-specific proceedings.	1% of utility's single hour peak load during the previous year	45 kW
LA	Net Billing	"Phase I" Modified NEM: December 2016 "Phase II" Net Billing: January 2020	NEM: Monthly excess credited to customer's next bill at retail rate (closed to new customers). Phase 1 NEM: Monthly excess credited to customer's next bill at the avoided cost rate. Phase 2 Net Billing: All exports compensated at the avoided cost rate.	0.5% of the utility's monthly jurisdictional retail peak load	Residential: 25 kW Commercial and agricultural: 300 kW

State	Compensation Mechanism	Transition Year from Net Metering to Modified Net Metering or Net Metering Successor	Compensation for Excess Generation	NEM Cap	System Size Restrictions
MI	NEM/Net Billing	2017 (DTE) 2021 (Consumers Energy)	NEM: Monthly excess credited at the retail rate. Net Billing: Hourly exports compensated as a monetary credit at avoided cost. As adopted for DTE, the rate is power supply minus transmission.	0.75% of utility's peak load during previous year	150 kW
NH	NEM currently, with modified net excess generation rate	2017	100 kW or less: Monthly excess credited as a monetary credit set at the sum of 100% of the energy service and volumetric transmission charges plus 25% of the volumetric distribution rate. Non-bypassable charges assessed on gross grid consumption during a month and excluded from the monthly credit. 100 - 1,000 kW: Monthly excess credited at the default energy rate.	100 MW	1 MW
NY	NEM currently for residential and small commercial customers, with additional charge based on system size beginning in 2022	2022	For residential and small commercial customers, monthly excess credited the customer's next bill at the retail rate. After January 1, 2022, a $/kW-DC customer benefit contribution charge will be assessed on NEM customers.	N/A	Solar: 25 kW for residential; 2 MW for non-residential; 100 kW for farm service. Varies by technology
SC	NEM currently. Solar Choice Net Metering beginning June 1, 2021.	2021	NEM: Monthly excess credited to the next bill at the retail rate. Solar Choice Net Metering: TBD.	N/A	20 kW for residential; 1,000 kW for non-residential
UT	Net Billing	2017	Excess as measured over 15-minute interval is credited at 90% of the average class rate (9.2 cents/kWh currently for residential) as a monetary credit. For larger rate classes the credit is at 92.5% of the average retail rate.	N/A	Residential: 25 kW Non-residential: 2 MW

Exhibit BDI-5

Key Examples of Jurisdictions Studying and Investigating Net Metering ("NEM")

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Arizona (Arizona Public Service)	Distributed Renewable Energy Operating Impacts and Valuation Study (2009)[1] The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2013[2], 2016[3])	E-01345A-13-0248 (2013 APS Lost Fixed Cost Recovery Charge) E-00000J-14-0023 (2014 Investigation into the Value of DG) E-01345A-16-0036 (2016 APS Rate Case) RE-00000A-17-0260 (2017 NEM Rulemaking)	Retail rate net metering retained, with a small monthly fee on APS net metering customers, through 2017. The Arizona Corporation Commission adopted a net billing policy for APS beginning in 2017. The export rate under APS's net billing is $0.1045/kWh through September 30, 2021.
California	The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California (2010)[4] Evaluating the Benefits and Costs of Net Energy Metering in California (2013)[5] Net-Energy Metering 2.0 Look-Back Study (2021)[6]	R.14-07-002 (2014 NEM "2.0" rulemaking) R.20-08-020 (2020 NEM successor tariff rulemaking)	Retail rate net metering (NEM 1.0) retained through 2017. NEM 2.0 in effect from 2017-2022 (est.). NEM 2.0 includes mandatory service under a TOD rate and retail rate credits minus non-bypassable charges. A new NEM Successor Tariff is now being developed in R.20-08-020 to take effect in 2022 (est.).

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1 https://appsrv.pace.edu/VOSCOE/?do=DownloadFile&res=J8PAM033116121012
2 https://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf
3 https://images.edocket.azcc.gov/docketpdf/0000168554.pdf
4 https://emp.lbl.gov/publications/impact-rate-design-and-net-metering
5 https://www.growsolar.org/wp-content/uploads/2012/06/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf
6 https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467448

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Colorado	Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System (2013)[7]	14M-0235E (2014 DG Cost Benefit Investigation) 16AL-0048E, 16A-0139E, 16A-0055E (2016 Cases Resulting in NEM Settlement) 18AL-0097E (2018 Roll-over Provisions to Xcel's NEM Agreed to in Rate Case) 19R-0096E (2019 Electric Rule Changes)	Retail rate NEM retained. A 2016 proposal by Xcel Energy to implement a Grid Usage Charge of up to $44.79 on residential customers was withdrawn as part of a settlement, resulting in NEM customers retaining retail-rate crediting.
Connecticut	Value of Distributed Energy Resources (2020, Draft)[8]	15-09-03 (2015 Investigation into NEM kWh Banking) 18-06-15 (2018 DG Tariff Development re Public Act 18-50) 19-06-29 (2019 Value of Distributed Energy Resources Study) 20-07-01 (2020 Development of Tariffs for Residential Renewable Energy re Public Act 19-35)	Retail rate NEM retained after multiple proceedings and despite legislation allowing for NEM changes. A 2018 law would have ended NEM but was revoked through a 2019 law. In February 2021, the Public Utilities Regulatory Authority ("PURA") retained retail rate net metering under a new "Netting Tariff" option. (A Buy-All, Sell-All option was also created.) PURA determined monthly netting was appropriate, even though Public Act 19-35 granted PURA discretion to impose other intervals, including instantaneous netting. NEM systems allowed to be "oversized" relative to historic usage to accommodate future load growth from EV and electric heating adoption.

[7] https://bit.ly/2ZIhfet.
[8] https://bit.ly/3aQTbMS

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Iowa	PV Valuation Methodology (2016)[9]	NOI-2014-0001 (2014 DG investigation) TF-2016-0321, TF-2016-0323 (2016 Alliant and MidAmerican NEM pilots) TF-2020-0235, TF-2020-0237 (2020 Alliant and MidAmerican DG Tariffs)	A 2014 DG investigation retained and expanded retail rate NEM, establishing utility NEM "pilots" for IOUs to study impacts of retail rate NEM over several years. SF 583 (2020) maintained NEM through 2027, after which a value of solar methodology will be used to determine compensation for exports.
Maryland	Value of Solar Report (2017)[10] Benefits and Cost of Utility Scale and Behind the Meter Solar Resources in Maryland (2018)[11]	RM 41 (2011 NEM Rulemaking) PC 40 (2015 Public Conference on Small DG Deployment) PC 44 (2016 Transforming Maryland's Distribution Systems) PC 48 (2017 Investigation re Costs and Benefits of DG for Electric Cooperatives)	Retail rate NEM retained after multiple proceedings and studies. 2018 Study found NEM benefits exceed costs.

9 https://www.growsolar.org/wp-content/uploads/2016/03/PV-Valuation-in-Iowa.pdf
10 https://bit.ly/3aJXsS8
11 https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Massachusetts	Value of Distributed Generation: Solar PV in Massachusetts (2015)[12] Massachusetts Net Metering and Solar Task Force Final Report to the Legislature (2015)[13]	16-64 (2016 Transition to "Market Rate" NEM and a Minimum Monthly Reliability Contribution ("MMRC") 16-151 (2016 IOUs' Petition re Revised Model NEM Tariff) 17-105; 17-146 (2017 Storage NEM Eligibility) 18-150 (2018 National Grid Rate Case Proposing MMRC) 19-24 (2019 IOUs' Revised Model NEM Tariff)	Near-retail rate NEM retained for residential customers. A reduced credit rate applies to certain other categories of customers. IOU proposals to implement a demand-charge or fixed-charge based MMRC have been denied by regulators or overruled through subsequent legislative changes. (2016 legislation allowed utilities to propose an MMRC, and 2018 legislation amended those provisions.)
New Hampshire	Value of Distributed Energy Resources Study (Anticipated Q1 2022)[14]	DE 16-576 (2016 Investigation on Alternative NEM Tariff Development) DE 16-873, DE 16-864 (2016 Liberty Utilities Large NEM Methodology) DE 18-029 (2018 Unitil Alternative NEM Tariff) DRM 19-158 (2019 NEM Rulemaking) DE 20-136 (2020 Eversource NEM Cost Recovery)	Retail rate NEM retained for customers <100 kW, with reduction to the credit rate for monthly net excess generation. Non-bypassable charges assessed on gross grid consumption during a month and excluded from the monthly credit. Value of DER Study is ongoing and will provide detailed information regarding costs avoided by NEM under general conditions, as well as at specific times and at particular locations.

[12] https://acadiacenter.org/resource/value-of-solar-massachusetts/
[13] https://www.mass.gov/doc/final-net-metering-and-solar-task-force-report/download
[14] *See* New Hampshire Public Utilities Commission, Docket No. DE 16-576.

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
New York	An Analysis of the Benefits and Costs of Increasing Generation From Photovoltaic Devices in New York (2012)[15]	14-M-0101 (2014 Reforming the Energy Vision) 15-E-0703 (2015 NEM Cost-Benefit Study) 15-E-0751 (2015 NEM Successor and Value of DER Phase I) 15-E-0751 (2017 NEM Successor and Value of DER Phase II) 17-01276 (2017 VDER Phase 2 Value Stack Working Group) 17-01277 (2017 VDER Phase 2 Rate Design Working Group)	Retail rate NEM retained for residential, small commercial, and behind-the-meter systems. In 2022, a \$0.69/kW to \$1.09/kW customer benefit contribution charge will apply as a means of ensuring funding for public benefit programs, but retail-rate NEM will continue. Value of DER (VDER) implemented for other customers. Gross exports accrue as a monetary credit at a utility-specific VDER rates composed of energy, generation capacity, distribution capacity (including possible local adder) and environmental value. System distribution capacity locked in for 3 years, local distribution capacity for 10 years, and environmental value for 25 years.

15 https://www.nyserda.ny.gov/About/Publications/Solar-Study

State (Utility)	NEM Studies	Recent NEM Dockets	NEM Outcome(s)
Utah	Value of Solar in Utah (2014)[16]	14-035-114 (2014 RMP Net Metering Cost-Benefit Investigation) 16-035-T14 (2016 RMP Temporary NEM Tariff) 17-035-61 (2017 Credit Rate for DG Customer Energy Exports)	In 2015, the Utah Public Service Commission rejected Rocky Mountain Power's (RMP) proposal that net metering customers be converted into a separate customer class but directed RMP to file a cost-of-service study on net metering customers in its next rate case. In September 2017, the PSC adopted a NEM "Transition Program" as a result of a settlement agreement. DG customers were compensated at fixed rates, which varied by rate schedule, and were equal to 90% of the average energy rate for residential customers and 92.5% for other customers, for any net kWh exports at the end of 15-minute increments, capped at 170 MW for residential customers and 70 MW for other customers. In October 2020, the PSC approved RMP's request to lower the export credit rate from \$0.092/kWh to \$0.05969/kWh in summer and \$0.05630/kWh in winter.

16 https://pscdocs.utah.gov/electric/13docs/13035184/255147ExAWrightTest5-22-2014.pdf

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit

Case No. 2020-00350

AFFIDAVIT OF BENJAMIN INSKEEP
VERIFICATION

JURISDICTION)
)
County of Marion)

The undersigned, Benjamin Inskeep, being first duly sworn, states the following: The prepared pre-filed Direct Testimony, and the Exhibits attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the pre-filed Direct Testimony if ask the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further, Affiant saith not.

Benjamin Inskeep

Benjamin Inskeep

SUBSCRIBED AND SWORN to before me this 4th day of March, 2021.

Amy Harris

NOTARY PUBLIC

My Commission Expires: 07-09-2027

AMY HARRIS
NOTARY PUBLIC
SEAL
STATE OF INDIANA
Commission Number NP0721226
My Commission Expires 07/09/2027