COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES CO. FOR AN ADJUSTMENT OF ITS ELECTRIC 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. 2020-00349

-and-

ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC CO. 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

PAUL J. ALVAREZ

On Behalf of the Kentucky Office of the Attorney General

March 5, 2021

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DIRECT TESTIMONY OF PAUL ALVAREZ

I. INTRODUCTION, QUALIFICATIONS, PURPOSE, AND PREVIEW

Q. Please state your name and business address.

A. My name is Paul Alvarez. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

Q. What is your occupation?

A. I am the President of the Wired Group, a consultancy specializing in distribution utility business planning, operations, investment, and performance measurement, including smart meters.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the Kentucky Office of the Attorney General (AG).

Q. Please describe your work experience and educational background.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S.

At Xcel Energy I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and metering policies). There I learned the economics of traditional monopoly ratemaking and associated utility economic incentives. I also learned a great deal about utility energy efficiency and demand response program impact measurement & verification (M & V).

I left Xcel Energy to lead the utility practice for sustainability consulting firm MetaVu in 2008. At MetaVu, I employed my M & V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are two of only three comprehensive, unbiased evaluations of smart grid post-deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[1] and an evaluation of Duke Energy's Cincinnati-area deployment for the Ohio Public Utilities Commission in 2011.[2]

[1] Alvarez et al, MetaVu. "SmartGridCity™ Demonstration Project Evaluation Summary". Report submitted to the Colorado Public Utilities Commission in the testimony of Michael G. Lamb, Exhibit MGL-1, proceeding 11A-1001E. Report dated October 21, 2011; filed December 14, 2011.

[2] Alvarez et al, MetaVu. "Duke Energy Ohio Smart Grid Audit and Assessment". Report to the Staff of the Public Utilities Commission of Ohio in proceeding 10-2326-GE-RDR. June 30, 2011.

In 2012, I started the Wired Group to focus exclusively on distribution utility business optimization. Wired Group clients include consumer, business, and environmental advocates. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I've educated new regulators and staff on grid modernization and distribution utility performance measurement.

Finally, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment, a book that helps laypersons understand smart grid capabilities, benefit prerequisites, and post-deployment performance optimization. I received an undergraduate degree in Finance from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at Northwestern University in 1991. Both degrees featured concentrations in Finance and Marketing.

Q. Have you appeared before the Kentucky Public Service Commission previously?

A. Yes, I have prepared testimony on behalf of the Attorney General regarding smart meters in three previous instances. The first instance was Duke Energy's Certificate of Public Convenience and Necessity (CPCN) for Smart Meters (Case No. 2016-00152). The second instance was in LG&E/KU's 2016 rate case, in which the Companies petitioned the Commission for approval to install smart meters (Case Nos. 2016-00370 and 2016-00371). As part of a global settlement in those cases, LG&E/KU ultimately withdrew their smart meter proposal. The third instance was in LG&E/KU's last request for a CPCN to install smart meters (Case No. 2018-0005). The Commission denied that request, which appeared to be prompted in part by my testimony questioning the Companies' projected benefits.

Q. What experience do you have before other state utility regulatory commissions?

A. I have testified or developed evidence presented in cases before state utility regulatory commissions on smart meters, associated rate designs, grid modernization, grid investment, and distribution utility performance measurement in California, Indiana, Iowa, Kansas, Maryland, Massachusetts, New Hampshire, New Jersey, North Dakota, North Carolina, Ohio, Oklahoma, Pennsylvania, and Washington. Brief descriptions of these proceedings, and case numbers for each, are provided in the "Regulatory Appearances" section of my Curriculum Vitae, attached as Appendix A. I have also consulted for clients engaged in state regulatory utility proceedings on these matters in Colorado, Florida, Hawaii, Michigan, South Carolina, and Virginia.

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

A. On behalf of the Attorney General, I provide testimony regarding the joint request by Kentucky Utilities and Louisville Gas and Electric Company ("Companies") for a CPCN to install Advanced Metering Infrastructure ("AMI") included in the Companies' instant rate case.

Q. What is your recommendation regarding the Companies' request for a CPCN to install AMI?

A. My recommendation is that the Commission approve the CPCN to deploy the Companies' proposed "AMI plus AMR gas-only" scenario, which is the scenario the Companies recommend, but only with reasonable and critical conditions for performance measurement, utility operations, and customer programs. These conditions are designed to minimize customer CPCN risk and maximize the benefits of the AMI deployment for customers. If the Commission decides to approve the CPCN without the significant and critical conditions I describe, available AMI benefits will be left on the table, and there is a high risk that AMI will not be deployed, "such that customers would never see an increase in revenue requirements associated with implementing AMI."[3] As a result, I cannot endorse CPCN approval without the reasonable and critical conditions described in this testimony.

Q. How is your testimony organized?

A. My testimony is organized in a way which supports the need for the significant and critical conditions for performance measurement, utility operations, and customer programs I recommend be attached to CPCN approval. The points my testimony will make include:

- AMI benefits are highly variable, not assured, and within the Companies' exclusive control and/or influence.
- Many sources of potential benefits are missing entirely from the Companies' AMI proposal.
- Some AMI capabilities are not in customers' interests to implement.

[3] See Direct Testimony of Kent W. Blake, page 16:21, Case Nos. 2020-00349 and 2020-00350.

- Customer CPCN risk merits better than "Bill Neutral" performance, as the Companies have asserted their recommended AMI deployment will deliver,[4] and the Commission should take the actions necessary to secure best outcomes.
- The Commission should only approve the CPCN if it attaches reasonable conditions to reduce customer risk and increase customer benefits. Customer risk will be lower, and benefits higher, if the Commission attaches recommended, critical, and reasonable conditions to AMI CPCN approval.

Q. Before you begin, can you summarize the differences between the Companies' present CPCN request to deploy AMI and previous requests?

A. The present CPCN request for AMI is indeed different from previous requests. In its Order rejecting the Companies' previous CPCN request for AMI, the Commission cited its concern that the Companies did not present compelling evidence that the proposed AMI deployment was a reasonable and least-cost alternative to the Companies' metering needs.[5] To their credit, the Companies have provided several improvements in the current CPCN to address the Commission's valid concern. For example, the Companies have provided detailed analyses which indicate that the Companies' recommended metering approach (AMI plus AMR for gas-only customers) has the potential to be least-cost. The Companies have also made several cost recovery proposals, to be employed in a future rate case, which attempt to ensure that the recommended metering approach could potentially be deployed, "such that customers would never see an increase in revenue requirements associated with

[4] Id.
[5] Kentucky PSC Case No. 2018-0005. Commission Order dated August 30, 2018. Page 10.

implementing AMI."[6] The AG is appreciative of these attempts by the Companies to address the Commission's concerns.

However, the AG is also appreciative of the Commission's interest in maximizing the benefits to customers of AMI technology, noted in the previous Order as "concerns regarding benefits to and options for (the Companies') customers".[7] The Commission's previous Order appears to me to express a concern that benefits available from AMI might fail to be seized by the Companies on behalf of customers. Indeed, the outcome described as highly probable by the Companies in the present CPCN (an AMI deployment with no increase in revenue requirements) still relies upon benefits which are highly variable, not assured, and under the Companies' exclusive control or influence. As a result, while I am highly complimentary of the Commission's approach to AMI in Kentucky to date, this testimony indicates that only a few reasonable conditions remain to assert which would guarantee the Companies' AMI deployment will be among the most successful for customers of any in the United States to date.

II. AMI BENEFITS ARE HIGHLY VARIABLE, NOT ASSURED, AND UNDER THE COMPANIES' EXCLUSIVE CONTROL AND/OR INFLUENCE

Q. Please explain why it is important for the Commission to understand that AMI benefits are highly variable, not assured, and under the Companies' exclusive control and/or influence.

[6] Witness Blake Direct, page 16 at 21.
[7] Commission Order in Case No. 2018-0005 dated August 30, 2019, page 11.

A. Grid modernization investments generally, and AMI investments specifically, are different than almost any other investment a utility can make. When a utility constructs a generating station, builds a substation, or installs a pole, the asset is either available for use on behalf of customers, and therefore used and useful, or it is not. Further, these assets are either required to deliver safe and reliable service, or they are not. There are no shades of gray. Smart meters are different; their primary function – measuring a customer's usage – is only a small part of a smart meter's capability, which could be fulfilled through less expensive means. The "smarts" of AMI meters are not required to deliver safe and reliable service; smart meters are only worth their incremental cost if the smart features are used to deliver *more benefits* to customers than their "dumb" counterparts. The manner in which the "smarts" of AMI meters are utilized varies widely from utility to utility, which in turn impacts the level of benefits delivered. There is nothing which forces a utility to maximize the benefits available from AMI, and I have observed missed opportunities in every AMI plan and AMI deployment I evaluate. Further, in the specific instance of the Companies' CPCN application, failure to secure projected benefits will result in a failure of the Companies stated objective: to deploy AMI "such that customers would never see an increase in revenue requirements associated with implementing AMI".[8]

Q. Why is there variability in how utilities utilize AMI capabilities?

A. Much of the variation is due to simple inertia. Change is difficult for people and organizations in the best of situations. With multiple priorities to address with limited resources, performance monitoring is a critical driver of change. In short, utilities will

[8] Witness Blake Direct, page 16:21.

maximize the benefits of AMI only if they want to, and monitoring is a good way to motivate them. If regulators wish to maximize AMI benefits for customers, post-deployment monitoring is essential.

Q. Can you share some examples of how AMI benefits can vary?

A. In this section of my testimony I will demonstrate sources of variation in the primary benefits the Companies must secure if they are to deliver on their intention of a "bill neutral" AMI deployment. I will also identify sources of variation the Companies' AMI business case does not consider, including:

- Additional sources of variation in conservation voltage reduction
- Additional sources of variation in e-Portal conservation
- Sources of variation in operational savings estimates
- Rate case timing as a source of benefit variation.

Q. Explain what you mean by the term "Bill Neutral".

A. "Bill neutral" is the short-hand term I use throughout this testimony to describe the intention of AMI cost recovery mechanisms the Companies propose in the CPCN. The Companies' intention is to manage the timing of AMI-related cost recovery such that, when netted against AMI-related benefits, "customers would never see an increase in revenue requirements associated with implementing AMI."[9]

Q. What is conservation voltage reduction, and how is it implemented?

[9] Direct Testimony of Witness, page 16:21.

A. Conservation voltage reduction (CVR) is nothing more than an intentional reduction in the average voltage of a circuit throughout its length. Some customer loads, called reactive loads (such as lighting and heating elements), use less energy at lower voltages. Utilities implement CVR by installing remotely-controllable voltage regulators and capacitors along the circuit as needed, and by installing remotely-controllable load tap changers at a circuit's "head end" (where electricity begins its journey from substation to customer load). Line sensors (or smart meters) are used to monitor voltage along the line (to make sure voltage doesn't drop below 110 volts), and software (typically part of ADMS or DMS systems, but also available stand-alone) is used to analyze the voltage and control the equipment. Ideally, all this operates in the background 24 hours a day, 365 days a year. This system is described in Companies' Witness Wolfe's testimony as "Volt/VAR Optimization".[10]

Q. How can CVR benefits vary?

A. Generally speaking, a well-planned CVR system can achieve significant voltage reductions, and benefits in excess of costs for customers. But, as with most "grid modernization" endeavors, results vary by utility. CVR requires dedicated management time and attention to maximize. Utilities vary in the amount of attention applied, and to the percentage of voltage reduction deemed satisfactory. The optimum locations for voltage regulators and capacitors changes over time as loads change. The software which can be set to reduce voltage can also be used to increase voltage (and therefore sales volumes) just as easily. There is also the chance for simple human error; CVR disabled

[10] Direct Testimony of John K. Wolfe, Exh. JKW-1, pages 27-28.

for circuit maintenance or construction work can simply be forgotten to be re-established after the work is completed. Finally, I am highly concerned that the budget allocated for VVO – a meagre $5.6 million,[11] or only $19,600 per circuit – will be woefully inadequate for the 400 circuits on which CVR benefits were calculated.[12] The speed and extent of VVO (and thus CVR) deployment present yet additional variables which can impact CVR benefit levels.

Q. Did the Companies assume CVR variation in their sensitivity analysis?

A. Yes, the Companies assumed a range of energy reductions from 1.4% to 2.6% on the 400 circuits to which it proposes to apply CVR.[13] However, given the variation I describe, I believe a much wider range of 0% to 3% to be more appropriate. If this single modification to the CVR benefit range is made, the likelihood that the Companies' entire AMI business case becomes negative rises from less than 1 in 100, as the Companies assert,[14] to 10 in 100.[15] (Note: These are the Companies' estimates of the likelihood of a negative AMI business case; the incremental variability described throughout this section of testimony indicates the likelihood of a negative business case to be dramatically greater than that indicated by the Companies' sensitivity analysis.)

Q. Please describe the Companies' e-Portal and associated benefit estimates.

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[11] Id., page 28.
[12] See Attachment provided by Companies in response to AG-KIUC DR 2-73(a).
[13] The Companies propose to deploy CVR on 400 of the Companies' 1800 circuits. It is totally appropriate to deploy CVR on a subset of circuits due to the incremental cost of CVR per circuit. A number of factors, from energy distributed to voltage and power factor variation, determine the circuits for which the incremental costs of CVR (and VVO) are most appropriate. This is beyond the scope of my testimony, but presents yet another potential source of CVR benefit variability.
[14] Direct Testimony of Lonnie E. Bellar, Exh. LEB-3, page 28.
[15] See Attachment provided by Companies in response to AG-KIUC DR 2-76(c).

A. The e-Portal is a website populated by smart meter data which customers can access. The e-Portal provides a variety of tools customers can use to manage their energy use, from detailed (hourly) usage charts and comparisons to the usage of similar homes, to the ability to download detailed usage data or sign up for e-mailed usage alerts (when it appears likely a bill will exceed a customer's pre-determined amount based on usage in the billing period to date). The Companies' consultant examined the change in usage of customers who volunteered to participate in the Companies' Advanced Metering Program after joining. The consultant compared this change in usage to customers not-enrolled in the Program over the same time periods, finding that a drop in usage among participants of at least 1.4% could not be explained. The consultant then attributed this drop in usage to smart meters and e-Portal access.[16] Then, responding to my critique in the Companies' previous AMI applications – that the results of voluntary, motivated participants could not be extrapolated to the entire customer population[17] – the Companies in the current case cut the consultant's energy savings estimate in half, to 0.7%. In using this figure in its business case, the Companies claim again to take a conservative approach, assuming a range of energy savings from zero to 0.7%, with a base case of 0.35%.[18]

Q. Do you have a critique of the Companies' e-Portal benefit estimates?

A. My critique is that the Companies applied the 0.35% energy savings rate to 100% of its sales volumes – not just all residential customers, but to all commercial and industrial customers, as well. Both these assumptions are extremely inappropriate, and result in

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[16] Direct Testimony of Lonnie E. Bellar. Exh. LEB-3, Appendix E, pages 1 & 3.
[17] Direct testimony of Paul Alvarez, Case Nos. 2016-00370 and 2016-00371, p. 13; Direct Testimony of Paul Alvarez, Case No. 2018-00005, pp. 29-31.
[18] Direct Testimony of Lonnie E. Bellar. Exh. LEB-3, Appendix A, page 19.

vastly overstated energy savings benefits. Consider the number of residential customers who will actually access their e-Portal, and use it to conserve energy. Let's generously assume that 1 of every 8 residential customers will access their e-Portal, and that *each* such residential customer will reduce their energy use by the 1.4% identified by the Companies' consultant. The result is an energy savings of 0.175%[19] — only *one-half* of the 0.35% assumed in the Companies' base case. While the Companies claim that their customers are clamoring for these conservation tools, I note that just 25,200 customers[20] — 3% of the Companies' 800,000 residential customers —have asked to have smart meters/My Meter access. (My Meter is the Companies' current e-Portal.)

Q. You indicate that the Companies' e-Portal energy savings estimates are overstated, but how does that relate to benefit variability?

A. The Companies' actions have a great degree of influence over how many customers actually access the e-Portal, and use it to conserve energy. Promotional efforts can vary by count, frequency, channels, incentives, creativity, messaging, and other characteristics. As an example of the impact of utility promotions on participation, one need look no further than the Companies' residential time-of-use pricing options, which have a grand total of 174 customers enrolled in them.[21]

Q. Why should the Companies' 0.35% energy savings estimate not be applied to commercial and industrial customers?

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[19] One-eighth of customers (12.5%) multiplied by 0.14% energy savings rate equals 0.175%.
[20] Direct Testimony of Eileen Saunders, pages 24-25; Direct Testimony of Lonnie E. Bellar, pages 56-57.
[21] Companies' 2019 U.S. Energy Information Administration Form 861. Form 6C, column A (Residential).

A. For a host of reasons. First, it is clearly inappropriate to apply the conservation impacts from residential program research to commercial and industrial customers; their energy use, loads, discretion, and characteristics are entirely different. Second, larger energy users have had interval energy usage data of the type smart meters provide – either through interval data recorders attached to their meters, or through their own building energy management, building automation, and process automation systems – for decades. Detailed energy usage data made available by smart meters offers nothing new to these customers. Third, large energy users have been dedicating resources to conservation for decades; it is unlikely the installation of a smart meter, or access to an e-Portal designed for residential customers, will amount to any appreciable increase of commercial and industrial customer conservation. Customers outside of General Service and residential rates comprise 29% of LG&E's sales volume and 26% of KU's sales volume,[22] meaning that the Companies' e-Portal conservation benefits are probably overstated by at least another 25% or so.

Q. Can you elaborate more about variability in utilities' operational savings benefits?

A. Yes. In my experience, utilities always over-estimate the headcount reductions AMI will be able to deliver, as well as the speed at which these headcount reductions can be achieved. For example, in meter reading, the Companies assume they will reduce headcounts from 197 to 4, or 98%;[23] my experience evaluating actual AMI deployments indicates a 98% reduction is not possible, and that even a 95% reduction is extremely difficult to secure. Savings in distribution operations are emblematic of the AMI benefit over-estimation in

[22] See Attachment provided by Companies in response to AG-KIUC DR 2-71.
[23] Companies' response to AG-KIUC DR 2-79(a).

which utilities typically engage; though savings of $200,000 annually are projected, no headcount reductions at all are planned.[24]

Q. You mentioned that savings delays are also common. Why is that a problem?

A. During deployment, cost savings delays are not a problem. I appreciate how the Companies have offered to establish a regulatory liability in the amount of projected savings during the deployment, and to amortize those credits as revenue requirement reductions post-deployment.[25] In this manner, delays during the deployment period present no losses for customers, as the Companies are at risk for securing savings of the size and timing projected. However, it does point out the important difference between the timing of benefits as recognized by the Companies, and the timing of benefits for customers when recognized in a rate case. Rate case timing is another source of benefit variability.

Q. Please explain this.

A. I expect the Companies will file a rate case as promptly as possible upon completion of the AMI deployment to begin cost recovery. Using past experience as a guide, it is likely the Companies will use a forecasted test year in that rate case. In my experience, forecasted test years are based in part on actual, historic accounting data for a certain period, adjusted for known differences. The issue is that the actual accounting data from the historic period used as a basis for the forecasted test year will not reflect all O&M cost reductions, as meter readers and meter services personnel will still be reading old meters and serving customers with old meters that year. Unless an adjustment is made to eliminate such costs in the

[24] Id., response to subpart (c).
[25] Direct Testimony of Kent W. Blake, Page 16:22.

forecasted test year costs, full benefits will not be reflected as rate reductions until the rate case *following* the rate case in which AMI meter cost recovery begins. This subsequent rate case could be five years later, ten years later, or longer. Other potential AMI benefits, from reductions in the bad debt reserve rate to increases in sales volume forecasts from improved theft detection, are also missed by customers in this manner. In fact, two to three years may be required before all the operating benefits from a completed AMI deployment are reflected in a rate case test year's books and records, thus presenting yet another source of benefit variability for customers.

Q. How do you recommend the Commission address AMI benefit variability?

A. The best way is to measure the actual benefits the Companies deliver, thereby holding them accountable for the "bill neutral" AMI deployment they offer. This is done through certain reporting requirements, such as department headcounts, as I explain further in my testimony, as well as careful review of forecasted test year cost and sales volume forecasts in the rate case in which AMI cost recovery is requested. But in addition, it is important to recognize that benefit variation represents a risk to customers. The Companies have made no commitment to deliver the level of benefits projected in their AMI business case[26] (other than the risk for cost savings shortfalls during the deployment period just mentioned). As a result, it is the *customers* who bear all the risk that their utility company will deliver projected benefits (beyond the deployment period), while the Companies bear none of that risk. Though the Companies project a small "cushion", significant benefit shortfalls of the type I've described will be paid through customer rate increases. I believe

[26] See Companies' response to AG-KIUC DR 2-59.

customers should be compensated for bearing this risk. In addition to measuring benefits, the best thing the Commission can do to compensate customers for CPCN risk is to ensure the Companies maximize all potential AMI benefits to the fullest extent possible. I have identified several potential benefits the Companies do not mention in their AMI business case. I describe these missed opportunities to compensate customers for CPCN risk in the next section of testimony, along with recommendations to maximize these benefits for customers.

III. MANY SOURCES OF POTENTIAL BENEFIT ARE MISSING ENTIRELY FROM THE COMPANIES' AMI PROPOSAL

Q. Please preview this section of testimony.

A. As described in the previous section, AMI benefits are highly variable, not assured, and under the Companies' exclusive control or influence. I've also testified that customers bear the risk for any shortfalls from the benefits projected. I believe the Commission should compensate customer CPCN risk by requiring the Companies to maximize all available AMI benefits. In this section, I will describe potential benefits missing entirely from the Companies' AMI proposal, as well as recommendations for maximizing these benefits, including:

- (Universal) Peak-Time Rebate Programs
- Revenue Assurance Programs
- Reliability Benefits
- Miscellaneous AMI data access and usage features which can benefit customers
- Inclusions in the proposed AMI regulatory liability which can benefit customers.

Q. What are peak-time rebate programs?

A. In my estimation one of the largest potential benefits from AMI, second only to meter reading cost savings, is to encourage customers to shift usage away from coincident system peak periods. The outsized benefits of system peak reduction include avoided spending in generation, transmission, and distribution capacity. Despite the potentially enormous benefit of AMI-enabled system peak reduction programs, the Companies do not mention them in their AMI proposal.

Peak-time rebate (PTR) is a program with a critical peak price feature which encourages customers to shift usage away from system peak periods. However, PTR encourages such shifts without the dramatic price spikes typically employed in rates with critical peak price features. Instead of price spikes, which penalize customers for using energy during peak periods, PTR provides an incentive to conserve energy during such periods. The incentive takes the form of a bill credit to customers who demonstrate conservation when requested. The larger the conservation demonstrated during system peaks, the larger the size of the bill credit.

Q. What is meant by a "universal" peak-time rebate program?

A. A peak-time rebate program is made "universal" by enabling all residential and small commercial customers with a smart meter to earn a rebate without requiring any special sign-ups or enrollments. A peak-time usage baseline is established (and modified over time) for each customer; each customer's usage during the peak event is compared to the baseline; any reductions from the baseline are quantified for each customer; and any associated rebates are paid to every customer demonstrating a reduction. There is no special rate (such as the Companies' "RTOD" rate) for which customers must enroll. Other than any PTR rebates earned, bills are calculated as they would normally be calculated based on the rate for which the customer is already enrolled. Thus, the ability to earn a rebate applies universally to all residential and small commercial customers.

Q. How do PTR programs work?

A. Each day, vertically-integrated utilities forecast the demand they expect the following day. On a limited number of days each year, a utility facing an exceptionally high capacity forecast issues a critical peak day alert to customers the prior afternoon or evening. (The hours for the critical peak period are generally standardized, such as 1-7 pm for a summer day, based on utility-specific load profiles, though alerts could conceivably advise periods tailored to specific events.) Customers then have the option to conserve during the peak period hours. The degree of conservation is calculated for each individual customer by comparing usage during the critical peak period to usage on a similarly hot recent day (or days) on which no alert was issued. This serves as the customer's baseline. Critical peak events could also be called on cold days, though the algorithms used to calculate baselines and conservation amounts would have to be different.

Rebates are generally paid at a high rate, such as $1 per kilowatt hour, to reflect their high avoided cost value. However, it is important that rebate amounts are calculated to accurately reflect avoided costs on a utility-specific basis, net of program administration and marketing costs. Higher rebates encourage greater customer usage behavior change, and are desirable, but care must be taken to ensure that non-participating customers do not end up subsidizing the rebates. Careful calculation of rebate amounts based on utility-specific avoided costs should render rebate size a non-issue.

Q. What are the advantages of peak-time rebate programs?

A. There are several. First, PTR programs can be offered universally, meaning there need be no sign-up requirement. One-hundred percent of customers could have an opportunity to earn a rebate immediately upon smart meter installation. This leads to quicker benefit realization for customers, and greater conservation during critical peak events, which are key drivers of system peak reduction and AMI benefit size. It also leads to comparatively lower marketing costs, which are significant for rates incorporating onerous price spike features.[27] Second, and quite important, there are no penalties for failing to conserve during peak periods, as there are with price spike rate designs. This feature is critically important for customers who lack the ability to respond to a critical peak event signal, including but not limited to: (i) low-income customers who may not have the ability (due to medical necessity) or the opportunity (due to a lack of discretionary loads); and (ii) customers who commute to work and lack the ability to remotely reduce consumption in their homes. The combination of these features makes universal PTR a best practice for "all-at-once" AMI deployments such as the Companies have proposed. PTR can also provide a reason for customers to look forward to smart meters, rather than to oppose smart meters.

[27] In my experience as a demand-side management program developer and program development manager, it was not uncommon for promotion costs to be $25-$50 per program participant. For a program with onerous critical peak price features, I would expect recruiting costs to be at the high end of this range, or even higher. In my experience, high recruiting costs per participant for opt-in rates or programs can render that rate or program cost-ineffective.

Q. Are there drawbacks to universal peak-time rebate?

A. There is some evidence that a small number of customers who reduce usage during peak hours fail to receive rebates, and that a small number of customers who do not reduce usage during peak hours do receive rebates. While I recognize the potential for such measurement errors, I note that "free drivers" and "free riders" are present in every time-varying rate, and that these drawbacks are more than outweighed by universal PTR programs' effectiveness, high and quick participation levels, low marketing costs, low-income suitability, and opportunity to maximize the benefits of an AMI deployment.[28]

Q. What are Revenue Assurance programs?

A. Revenue assurance programs are either customer programs or operational practices implemented by utilities to reduce bad debt expense and detect unbilled revenue (theft). Smart meters can help secure these benefits, but only if accompanied by enhanced utility programs or operations. Prepayment programs, for example, result in no bad debt. The Companies discuss offering a prepayment program in their AMI proposal, but no associated reduction is included in their AMI benefit estimates.[29] As all customers cover bad debt write offs in rates, this is a potential smart meter benefit. But the Companies did not include bad debt reductions as a benefit in their AMI business case.

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[28] In a series of rate cases following AMI deployments, the Maryland PSC ordered all investor-owned utilities in Maryland to offer universal PTR. See, as examples, the BG&E, Pepco, and Delmarva universal Peak Time Rebate programs described at https://www.bge.com/WaysToSave/ForYourHome/Pages/EnergySavingsDays.aspx; https://www.pepco.com/WaysToSave/ForYourHome/Pages/MD/PeakEnergySavingsCredit.aspx; and https://www.delmarva.com/WaysToSave/ForYourHome/Pages/DE/PeakEnergySavingsCredit.aspx

[29] While on the subject of prepayment programs, for future reference, I ask the Commission to consider lower rates for such programs. Lower bad debt, collections, and working capital costs, to the extent such costs are reduced by prepayment programs, should be reflected as lower rates for prepayment customers.

Similarly, smart meters can help detect unbilled revenues. Smart meters are equipped with tamper detectors which can indicate theft. Interval data can be analyzed to identify instances of meter bypass (in which a thief bypasses his or her meter with wires for a portion of a billing period). For poly-phase customers, smart meter data can be used to determine when energy use on a phase ceases being recorded (leading to unbilled revenue). All these potential AMI benefits require modifications in the Companies' operating procedures and practices to secure, and to maximize. But the Companies did not include unbilled usage reductions among projected AMI benefits.

Q. Why do you claim the Companies have not identified reliability improvements as an AMI benefit? Mr. Wolfe's testimony dedicates multiple pages to this topic.

A. Yes, Mr. Wolfe's testimony includes descriptions of how AMI capabilities could be used to improve reliability. But he provides no estimate of the system-wide SAIFI and SAIDI[30] improvements the Companies will deliver as a result of the AMI deployment. Without quantified SAIFI and SAIDI improvement estimates, Mr. Wolfe's descriptions of how AMI data could be used to improve reliability constitute nothing more than descriptions of how AMI data could be used to improve reliability. In my experience with evaluating the reliability benefits of AMI, the results have been disappointingly small. As a result, I conclude reliability benefits – at least ones for which the Companies could be held accountable for achieving – are missing from the Companies' AMI proposals.

[30] SAIFI measures average service outage frequency; SAIDI measures average service outage duration.

Q. What are the miscellaneous features the Companies have excluded from their AMI business case?

A. The Companies did commit to implementing these AMI features in discovery, but I wish to bring those commitments to the Commission's attention. One of these features is the opportunity to use AMI data to improve demand-side management (DSM) program impact measurement accuracy.[31] More accurate DSM program impact measurement helps ensure that programs which are not cost-effective are discontinued. More accurate DSM program impact measurement also helps ensure that lost revenue adjustments are appropriate to *actual* sales volume reductions. Another important feature to which the Companies committed in discovery is compliance with Green Button's Connect My Data standard.[32] The Connect My Data standard specifies a common way for customers to authorize third parties to access their smart meter data, as well as a common approach for third parties to access the smart meter data of authorizing customers on a routine, automated basis from utilities. The Connect My Data standard compliance enables customers to choose the energy management software, smart phone app, or service provider of their choice with minimal friction, and is therefore ideal for prompting market development and innovation. Five state regulatory commissions have mandated Connect My Data standard compliance for investor-owned utilities with smart meters, including California, Colorado, Illinois, New York, and Texas.[33]

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[31] Companies' response to AG-KIUC DR 2-73.
[32] Companies' response to AG-KIUC DR 1-220.
[33] California PUC D.13.09.025 dated September 19, 2013; Colorado PUC 16A-0588E, Decision filed July 25, 2017, p. 7; Illinois Commerce Commission 14-0507, Order dated July 26, 2017; New York PSC 14-M-0101, Order dated April 20, 2016, p. 61; Texas Administrative Code Title 16, Part 2, Chapter 25, Section 25.130 (Advanced Metering).

Q. What are the "inclusions in the proposed AMI regulatory liability" which could benefit Customers?

A. While I have been exposed to accounting issues throughout my career, regulatory accounting is a specialty I believe is best left to the experts. AG-KIUC revenue requirements witness Mr. Lane Kollen describes multiple benefits he testifies should be included in the AMI regulatory liability the Companies have proposed to accrue AMI-related benefits owed to customers during deployment. My accounting expertise is sufficient to recognize and endorse the benefits Mr. Kollen describes as missing from the Companies' recommended AMI deployment scenario, though the actual descriptions and calculations of these missing benefits are better suited to Mr. Kollen's expertise. In summary, these benefits relate to the fall in revenue requirements as the Companies' existing meters are retired, and which will accrue to the Companies as excess revenue, unless specifically included in the AMI regulatory liability as a condition for CPCN approval established by the Commission.

Q. Why do you believe the Companies have omitted all these potential AMI benefits from their AMI proposal?

A. Only the company can know the answer to this question. But it stands to reason that a regulated utility will sometimes act in its self-interest, and, in so doing, may limit the quantified benefits to those necessary to secure approval. Fewer quantified benefits allow fewer opportunities for a regulator or stakeholder to hold the utility accountable for performance. For example, regarding universal peak-time rebate, I would not want to bring to the Commission's attention any program which might reduce coincident system peak, thereby avoiding investments to increase capacity which grow rate base (and earnings per share). As a result of these tactics, however, the observable margin for error is uncomfortably small from a customer perspective. I discuss this and other rationale for the Commission to set conditions for CPCN approval later in my testimony. But before I address this topic, I address AMI capabilities which are not in customers' best interest, and which should also be the subject of CPCN approval conditions I recommend the Commission establish.

IV. SOME AMI CAPABILITIES ARE NOT IN CUSTOMERS' INTEREST TO IMPLEMENT

Q. Please provide a preview of this section of testimony.

A. In this section of testimony I address AMI capabilities which are not in customers' interest to implement. I bring these to the Commission's attention so that the prohibition of these capabilities can be considered by the Commission as additional conditions for CPCN approval. The AMI capabilities which are not in the interest of residential and small business customers to implement include 1) adding a demand charge component to these customers' rate structures; and 2) making time-of-use rates mandatory for these customers.

Q. Why are demand charges inappropriate as a component of residential and small commercial customers' rate structures?

A. Demand charges have been in place for industrial customers for over 100 years. Demand charges were initially promoted as a way to efficiently divide historic accounting costs. But, as modern economists now recognize, the best way to design rates is in such a way as to optimize future costs, and more precisely, future marginal (incremental) costs of the system the customer uses.[34]

While some utilities may prefer demand charges as an attempt to reduce their economic exposure to changes in sales volume, there are *better* ways to do that, such as improved sales forecasting; moreover, utilities *always* have the option of filing a rate case to address such changes. Others might argue that demand charges better reflect the cost of a customer's use of the system. But this generalization makes assumptions that simply are not true, including 1) that an individual customer's peak is the same as a system peak; and 2) that all capacity investment is related to demand.[35] Most industrial and commercial customers who are subject to demand charges are capable of taking measures to avoid spikes in power bills such as can occur during times of peak usage. However, residential loads are much more diverse such that imposition of a demand charge would impose significant hardships. Further, if structured as a coincident peak demand charge, the demand charge would force many to either reduce their consumption during times of peak usage, or to incur major hikes in their electric bills. Given that critical residential loads (air conditioning, electric space heating, and refrigeration) depend on electricity, being forced to reduce consumption during peak load hours would force adversities upon many residential customers, especially the elderly and customers with health conditions. Some residential customers will likely pull the plug on their refrigerators, raising the threat of food spoliation. The result would thus be major inequities and impracticalities for many

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[34] LeBel M and Weston F. "Demand Charges: What Are They Good For? An Examination of Cost Causation". Whitepaper by the Regulatory Assistance Project. November, 2020. Page 11. (Note: this citation is provided as a though-leading treatise on demand charges. The AG does not take a position on all issues presented in the paper.)
[35] Id., pages 13-25.

customers. To summarize, for all the customer hardship and confusion they will cause, demand rates will simply not deliver the economic benefits some people claim are available. Although in the current case the Companies are not seeking permission to implement a residential demand charge, the AG is providing notice that he will vehemently oppose any such effort by any Kentucky utility subject to the Commission's jurisdiction.

Q. Do you have an opinion regarding time-varying rates?

A. There are difficulties here too. Research indicates that time-varying rates without a critical peak price feature are not very useful for reducing coincident peaks,[36] which is where most of the potential value from time-varying rates lies. While a critical peak price feature can be added to time-varying rates, for the reasons described earlier, critical peak prices are not equitable, and are regressive on certain types of residential and small commercial customers. This leads me to conclude, as recommended earlier, that the universal approach to peak-time rebate represents the best balance among competing priorities. Adding demand charges to residential and small commercial rates, or making time-varying rates mandatory, are not good uses of AMI capabilities.

[36] Faruqui A and Palmer J. "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity." EDI Quarterly. Volume 4, No. 1. April, 2012. Figure 2, page 4.

V. CUSTOMER CPCN RISK MERITS BETTER THAN "BILL NEUTRAL" AMI PERFORMANCE, AND THE COMMISSION SHOULD TAKE THE ACTIONS NECESSARY TO SECURE BEST OUTCOMES

Q. Why do you believe the Companies' assurances regarding a "Bill Neutral" AMI deployment are insufficient?

A. First of all, as described in Section II of my testimony, AMI benefits are highly variable, not assured, and are under the Companies' exclusive control and/or influence. As discussed, I am particularly concerned about the achievement of conservation and coincident peak reduction benefits. Second, the margin of error is very small. It would not take much in the way of cost increases or benefit shortfalls for AMI deployment to be something other than bill neutral (meaning, resulting in rate increases).

Q. How small is the margin of error, exactly?

A. According to the Companies' projections, the recommended AMI + AMR Gas Only proposal will save just $53 million compared to the status quo over 30 years.[37] As the Companies estimate the costs of the proposal at $681 million, a combination of benefit shortfalls and cost over-runs amounting to just 7.8% of cost will be enough to violate the goal of a bill neutral AMI deployment. Some other relevant anecdotal statistics include:

- $53 million over 30 years is just $1.77 million annually.
- $1.77 million is just 1/2% of the $310.5 million[38] annual rate increase the Companies have requested in the current rate case.

[37] Direct Testimony of Lonnie E. Bellar. Exhibit LEB-3, Table 6, page 26.
[38] Direct Testimony of Paul W. Thompson. Page 22:15.

Q. Why should the Commission expect better than "Bill Neutral" performance from the Companies' AMI deployment, and take actions to secure this outcome?

A. First, performance better than "bill neutral" is available from an AMI deployment, as indicated by the missing benefits described in Section III of my testimony. If this is the case, I would urge the Commission to pursue this outcome. Second, the Commission's mission, which is "to foster the provision of safe and reliable service at a reasonable price . . . while supporting (utility) operational competence by overseeing regulated activities," supports this pursuit.[39] And third, as described earlier, if the CPCN asks the customers to assume the risk that AMI benefits could be less than costs, resulting in bill increases, the Commission should help ensure that *all* available benefits are pursued as a reward for assuming that risk.

VI. THE COMMISSION SHOULD ONLY APPROVE THE CPCN IF IT ATTACHES REASONABLE CONDITIONS TO REDUCE CUSTOMER RISK AND INCREASE CUSTOMER BENEFITS

Q. Will you please summarize your testimony to this point?

A. I recommend that the Commission approve the CPCN, but only upon addition of several key, reasonable conditions which should be well within the Companies' ability to provide. My testimony describes the following realities:

- AMI benefits are highly variable, not assured, and within the Companies' exclusive control.

[39] Kentucky PSC website page "About the Public Service Commission". Accessed via Internet at https://psc.ky.gov/Home/About#AbtComm

- Many sources of potential benefit are missing entirely from the Companies' AMI proposal.
- Some AMI capabilities are not in customers' interests to implement.
- Customer CPCN risk merits better than "Bill Neutral" AMI performance, and the Commission should take the actions necessary to secure *best* outcomes.

Q. What actions could the Commission take to secure best outcomes from the Companies' AMI deployment?

A. The Commission could establish critical conditions for CPCN approval. I recommend these conditions include: 1) that the Companies develop missing benefits; and 2) that the Commission establish annual AMI benefits measurement reporting for ten years. In establishing these two reasonable conditions, this Commission will have ensured the Companies' AMI deployment is the most successful of any AMI deployment by a U.S. investor-owned utility to date from a customer perspective.

Q. What missing benefits do you recommend the Commission require as conditions for CPCN approval?

A. The Commission should establish the following requirements as conditions of CPCN approval:

- The Commission should require the Companies to implement a universal peak-time rebate program. The program should enable all customers to earn rebates without registration, and rebates should be available immediately upon AMI installation.

- The Commission should require the Companies to develop benefit estimates in dollar terms from AMI-related capabilities to reduce bad debt and unbilled revenues by year, as the Companies have for other AMI-related capabilities.
- The Commission should require the Companies to develop SAIFI and SAIDI benefit estimates from AMI-related capabilities by year.
- The Commission should require that AMI data be used to estimate the impact of demand-side management programs on an ongoing basis.
- The Commission should require that the Companies maintain compliance with Green Button's Connect My Data standard.
- The Commission should require that the excess revenue requirements described in AG-KIUC witness Mr. Kollen's testimony be included among the regulated liabilities accrued, and credited to customers, post-deployment; and
- The Commission should prohibit the Companies from using AMI to implement demand charge components and/or mandatory time-of-use rates for residential and small commercial customers.

Q. What reporting requirements do you recommend the Commission establish as conditions for CPCN approval?

A. The Commission should require the Companies to report on each of the following metrics annually for 10 years (the Commission may require reporting from some types of programs indefinitely):

Program	Measures
Conservation Voltage Reduction	By circuit: 1) Average voltage at which energy is delivered throughout a circuit, baseline (3 years prior to deployment); 2) Average voltage at which energy is delivered throughout a circuit (each year).
e-Portal	By year: 1) unique number of customers who have accessed their usage dashboard; 2) unique number of customers who have accessed their own usage dashboard more than once; 3) customers enrolled in the high bill alert feature; 4) customers with a completed Property Profile.
Operational cost savings	Year-end headcounts in 1) meter reading; 2) meter services
Rate case timing	In any year in which a rate case is filed to recover AMI costs, ensure the following are reflected: 1) reductions in test year costs for non-recurring spending in meter reading and meter services; 2) increases in sales volume forecasts from AMI-related unbilled revenues; and 3) reductions in the bad debt reserve rate due to AMI.
Universal Peak-time Rebate	1) Count of customers earning a rebate; 2) Count of rebates issued per event; 3) Total amount of credits ($) issued per event
Unbilled Revenue, theft	1) Number of theft incidents detected; 2) Average days from theft alert to investigation; 3) Average days from investigation to resolution (billing); 4) kWh billed (of valid theft incidents detected)
Unbilled Revenue, bad phase	1) Count of meters identified with bad phase; 2) Average days from identification to meter replacement; 3) kWh billed on bad phases
SAIFI	1) Failing transformers identified in advance; 2) SAIFI improvement from transformers replaced prospectively.
SAIDI	1) SAIDI improved by faster outage reporting; 2) SAIDI improved by faster outage diagnosis; 3) SAIDI improved through nested outage detection.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES CO. FOR AN ADJUSTMENT OF ITS ELECTRIC 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. 2020-00349

-and-

ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC CO. 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 PAUL J. ALVAREZ

State of Colorado)

Paul J. Alvarez, being first duly sworn, states the following:
The prepared Pre-Filed Direct Testimony and Schedules attached thereto constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief his statements made are true and correct. Further affiant saith naught.

Paul J. Alvarez

SUBSCRIBED AND SWORN to before me this 17th day of February, 2021

NOTARY PUBLIC

My Commission Expires: March 17th, 2024

RAVEN FURLONG
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20204010679
MY COMMISSION EXPIRES MAR 17, 2024

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Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

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Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

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Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

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Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

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Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.