BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
COMMONWEALTH OF KENTUCKY

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN ADJUSTMENT	)	Case No.
OF ITS ELECTRIC RATES AND FOR CERTIFICATES	)	2016-00370
OF PUBLIC CONVENIENCE AND NECESSITY	)	

-and-

ELECTRONIC APPLICATION OF LOUISVILLE	)	
GAS & ELECTRIC COMPANY FOR AN	)	Case No.
ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	)	2016-00371
AND FOR CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY	)	

DIRECT TESTIMONY

OF

PAUL ALVAREZ

ON BEHALF OF THE
OFFICE OF THE ATTORNEY GENERAL

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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 150963, Lakewood, CO 80215.

Q. What is your occupation?

A. I am the President of the Wired Group, a consultancy specializing in the optimization of distribution utility businesses and operations as they relate to grid modernization (including smart meters), demand response, energy efficiency, and renewable generation.

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, as well as the impact of self-generation, energy efficiency, and demand response on utility shareholders and management decisions. I also learned a great deal about utility program impact measurement and 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 the only two 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]

In 2012 I started the Wired Group to focus exclusively on distribution utility businesses and operations as they relate to grid modernization, demand response, energy efficiency, and renewable generation. Wired Group clients include utilities, regulators, consumer and environmental advocates, and industry associations. 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 <u>Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment</u>, a book that helps laypersons understand smart grid capabilities, optimum designs, 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.

[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.

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

A. Yes. I prepared testimony in 2016-00152, Duke Energy's Certificate of Public Convenience and Necessity (CPCN) for Smart Meters, on behalf of the AG. This Case is still pending before the Commission.

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

A. I have testified or developed evidence in cases before state utility regulatory commissions on smart meters, associated rate designs, grid modernization, and distribution utility performance measures in California, Colorado, Kansas, Maryland, and Ohio. 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.

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

A. I provide testimony recommending that the Commission reject the Companies' proposal to install an Advanced Metering System (AMS). This recommendation is based principally on the fact that the Companies' benefit projections are overstated, and that AMS costs are highly likely to exceed customer benefits if the Commission approves the AMS deployment. I present several supporting arguments, and my testimony is organized as described immediately below:

- The AMS customer benefits projected by the Companies are significantly overstated, unlikely to be achieved, and unlikely to exceed customer costs.

- The Companies can take additional actions to increase customer benefits delivered by AMS.
- These additional actions will not likely be sufficient to deliver a favorable benefit-cost ratio.
- In the event it approves the AMS proposal against my recommendation, the Commission can take action to reduce economic risks to customers.

Q. Before you present these arguments, can you please provide your overall impression of the state of AMS in the United States today?

A. Certainly. In general, I believe AMS can deliver economic benefits to customers in excess of costs under highly specific conditions. The conditions required to deliver benefits in excess of costs include utilities highly motivated to deliver benefits, engaged customers conveniently able to take required actions, regulators who oversee post-deployment benefit delivery, and wholesale markets available for various parties to capture available economic value. Unfortunately, I have not seen all these conditions exhibited in any AMS deployment to date. Research that my teams have conducted to measure benefits from AMS post-deployment indicates high variability in the level of benefits actually delivered, resulting in unfavorable benefit-cost ratios for customers.[3]

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[3] Benefit-cost ratios are typically expressed as a ratio of benefits to costs. For example, project benefits of $20 compared to project costs of $10 would be expressed as a 2:1 benefit-cost ratio ("favorable", or "positive" if greater than 1); project benefits of $5 compared to project costs of $10 would be expressed as a 0.5:1 benefit-cost ratio ("unfavorable" or "negative" if less than 1).

Q. Tens of millions of AMS meters have been installed in the U.S. in the past few years at a cost in the trillions of dollars. Are you suggesting this investment was wasted?

A. No. There is certainly potential to secure benefits in excess of costs for AMS systems that have been installed. I simply suggest that the highly specific conditions required to do so have not yet existed. Investor-owned utilities (IOUs) are highly motivated to invest capital in their distribution grids, including AMS, and to recover associated costs and profits as permitted through monopoly regulation. This is particularly true today; competitive wholesale markets have revealed excess generation capacity, virtually eliminating utilities' generation investment and profit opportunities. As IOUs' ability to invest in generation falls, interest in investing in distribution (and AMS) increases. Other parties stand to gain from AMS investment as well, from information technology consultants and equipment manufacturers to governments hoping to stimulate jobs. However, there is no similar economic motivation for IOUs to secure post-deployment benefits from AMS. The throughput incentive discourages utilities from pursuing conservation; the Averch-Johnson effect[4] discourages utilities from avoiding new generation plant construction; and holding rate cases when costs are falling (as from an AMS deployment) transfers such benefits to customers from shareholders. Hence my skepticism of the Company's benefit projections, which I will support throughout this testimony.

[4] The Averch-Johnson effect, named after the authors of a 1962 paper "Behavior of the Firm Under Regulatory Constraint", describes IOU's capital investment incentive under cost-based ratemaking. To summarize, the Averch-Johnson effect relates IOUs' capital investment incentive – to grow rate bases more than may be required to deliver safe, reliable service – to the fact that IOU profits grow as the size of rate bases grow.

II. AMS BENEFIT PROJECTIONS ARE SIGNIFICANTLY OVERSTATED

Q. Please explain why you believe the Companies' AMS benefit projections are significantly overstated.

A. I have carefully examined the Companies' AMS benefit projections, including information provided in pre-filed testimony and through discovery. I find three of the Companies' specific benefit projections and/or assumptions particularly troubling, and I will address them individually:

- The Companies calculate benefits assuming AMS will last 21 years,[5] though almost all IOUs' benefit calculations assume a 15-18 year useful AMS life;
- The Companies' ePortal conservation benefit projections are dramatically overstated, for three reasons to be described further below; and
- The Companies' projections of non-technical loss recovery are overstated.

Q. Please describe your concern regarding the Companies' use of a 21-year AMS life to calculate AMS benefits.

A. It is rational to assume benefits over an asset's useful life[6] when calculating benefit projections. Assuming benefits will continue beyond an asset's useful life overstates benefits, as an asset is expected to be replaced and/or be otherwise unavailable beyond its useful life. In AMS business cases, some IOUs assume longer benefit periods than

[5] Case Number 2016-00371, Companies' responses to AG 1- 341-343; 345-346; and 348.

[6] The Financial Accounting Standards Board (FASB) defines useful life as "the period over which an asset is expected to contribute directly or indirectly to future cash flows." Financial Accounting Standard 142.

may be appropriate in order to increase benefit projections. Such increases are not generally warranted.

The generally-accepted useful life for AMS is 15 years. The table below lists the benefit periods of a number of recent AMS business cases with publicly-available information. I know of no AMS proposal approved by a regulator in which an IOU's benefit time period is as long as the Companies'. The longest I know of is 18 years.

IOU	State	Docket	Year	Benefit Years	Customers (millions)	Regulatory Approval?
Ameren	IL	12-0244	2012	18	1.22	Yes
ConEd	NY	15-E0050	2015	18	3.40	Yes
Massachusetts Electric	MA	15-120	2015	15	1.32	TBD
KU/LGE	KY	00370/1	2016	21	0.92	TBD

Q. Are there other reasons to believe AMS useful life should not exceed 15 years?

A. Yes. The Companies' own depreciation expert acknowledges, "The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential life of 25 years."[7]

Q. You believe the Companies' 21-year benefit period is too long. But what other evidence do you have that 15 years is appropriate?

[7] Case Number 2016-00371. Pre-filed direct testimony of Companies' witness John P. Spanos. Page 15, line 7. Nov. 23, 2016.

A. Actually, there is evidence that a 15-year life for AMS is *too long*. In discovery, the Companies reported that of the 1,677 AMS meters installed for the Companies' Responsive Pricing/Smart Meter Pilot from 2007-2009, only 376 are still in service as of December 31, 2016.[8] This yields a 7-9 year survival rate of only 22.4%. The Companies explain in discovery that most AMS meters were replaced due to an LCD display failure. While the AMS meter manufacturer has likely corrected such an issue by now, the issue is indicative of the more complex and sensitive nature of electronic meters compared to the traditional mechanical type, and why shorter useful lives are indeed appropriate and have become the industry standard.

As further evidence that a 15-year life for AMS may be too long, I cite AMS meter manufacturers' standard 5-year warranty offer, which the Companies confirmed in discovery.[9]

Q, By how much does the use of a 15-year life, rather than the 21-year life assumed by the Companies, impact the Companies' AMS benefit projections?

A. The impact on the Companies' benefit projections is extremely significant. In discovery, the Companies were asked to recalculate benefit projections over a 15-year useful life rather than the 21-year useful life assumed. In response, the Companies provided the information used to create the table below.[10]

[8] Case Number 2016-00371. Response to AG DR 2-94.

[9] Case Number 2016-00371. Companies' response to AG DR 1-328

[10] Case Number 2016-00371. Companies' response to AG DR 1-339

	Nominal Benefits	Present Value of Benefits
15-year useful life	$713.4 million	$343.4 million
20-year useful life[11]	$1,019.8 million	418.1 million
	($306.4 million)	($74.7 million)

Q. Please explain why you believe the Companies' ePortal benefit projections are dramatically overstated.

A. As the author of the paper cited by the Companies regarding ePortal benefit calculations,[12] I am familiar with the role of, and the research on, energy usage data feedback in energy conservation. I identify three significant errors, and one significant observation, in the Companies' ePortal benefit projections:

- The Companies' assumption regarding the rate at which customers will access the ePortal is extremely high and not supportable.
- The level of conservation benefit assumed per ePortal visitor is not supported by energy usage data feedback research.
- The Companies used customers' energy bills, rather than fuel costs, as the basis for ePortal conservation benefit projections.
- The Companies have no incentive to maximize the energy conservation potential of the ePortal benefits..

[11] Case Number 2016-00371. Exh. JPM-1, page 38.

[12] Smart Grid Consumer Collaborative. *Smart Grid Economic and Environmental Benefits.* Secondary research conducted by the Wired Group. October 8, 2013.

Q. Please explain why the Companies' assumption about the rate at which customers will access the ePortal is extremely high and not supportable.

A. The Companies assume 48% of customers will access its ePortal, and that 36% of these visitors will conserve energy through the use of the portal, yielding an effective ePortal customer access rate of 17.3% (48% x 36%). The 48% figure appears to originate from Company experience with its existing DSM-EE "AMS Customer Offering". The Company reported "My Meter Welcome Site" page views of 1,821 to 2,125[13] (depending on how one counts) from the 4,181 customers enrolled/4,072 AMS meters installed in the program,[14] which is roughly equivalent to 48%. However, customers participating in the AMS Customer Offering are the most engaged and interested energy consumers the Companies serve. Indeed, the 4,181 customers enrolled in the program since its inception (June, 2015) amount to a participation rate of less than ½ of 1% of the Companies' customers (916,220).[15] This level of participation is consistent with my experience, and much closer to what an ePortal offered to all customers might experience. For the Companies to have extrapolated the ePortal access rate of the most engaged customers – the top 1/2 of 1% -- to *all* Customers in the Companies' service territories is aggressive, to say the least.

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[13] Case Number 2014-0003. "Advanced Metering Systems 2016 Annual Report". January 31, 2017. Page 4.

[14] Ibid, page 3

[15] Case Number 2016-00371. Companies' response to AG DR1-329c.

In addition, the Welcome Site page view counts are much higher than the page views of all the other available "My Meter" applications with true conservation potential:[16]

"My Meter" page	Page views	Unique Page views
"Charts View"	59	56
"Data View"	50	47
"Notifications"	48	42
"Profile"	44	41

Considering that a single participant could likely access all four of these pages in a single My Meter visit, it's certainly possible that as few as 60 customers have ever used My Meter portal functions out of more than 900,000 customers served by the Companies.

Q. Please explain why the Companies' conservation benefit per ePortal visitor is not supported by energy usage data feedback research.

A. The secondary research report I authored for the Smart Grid Consumer Collaborative cited research indicating that conservation levels (energy use reductions) of 5% to 15% are available from energy usage data feedback.[17] These particular levels of

[16] Case Number 2014-0003. "Advanced Metering Systems 2016 Annual Report". January 31, 2017. Page 4.

[17] Darby, S. "*Literature review for the Energy Demand Research Project*." Environmental Change Institute, University of Oxford. In Home Displays, pages 13-19.

conservation were recorded in research of electric and gas customers with access to in-home energy displays, which conveniently, continuously, and conspicuously advised participants of their energy use in real time. The Companies' propose no such displays as part of their AMS or ePortal offering, and thus cannot claim significant conservation benefits from ePortal visitors.[18]

To their credit, the Companies assume only a 3% level of conservation benefit among those customers who access their energy usage data from a portal.[19] However, I know of no well-controlled study which indicates that accessing energy usage data via an internet-based portal delivers any statistically significant conservation benefits at all.

Q. Please explain why the use of customer bills, rather than fuel costs, as the basis for ePortal conservation benefits projections overstates those projections.

A. I note that the Companies base conservation benefits from the ePortal on the size of an average customer's bill.[20] While this approach may be appropriate in calculating conservation benefits for any individual customer in the short term, this approach is incorrect for calculating customer-wide benefits in the long term.

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[18] An in-home display is a device which can be placed in a conspicuous location in a customer's home. Energy usage is displayed prominently, continuously, and in near real-time. Contrast this to a website, which requires customers to 1) consider visiting the site; 2) sit down at a computer (which not all customers own); 3) register (to link their computer securely to their meter's data) and, finally, 4) examine usage data (which, quite importantly, is only available on a one-day lag in most AMS deployments). The difference in usage impact between an in-home display and a portal is readily apparent.

[19] Case Number 2016-00371. Exh. JPM-1, page 157.

[20] Ibid, page 157.

Q. Please explain.

A. The Companies base their conservation benefit assumptions on an average customer's bill.[21] By extension, this means the Companies assume a 3% conservation effect will deliver economic benefits to customers equal to 3% of the Companies' costs.

In reality, however, electric conservation only reduces the Companies' fuel costs. Conservation does not reduce any other costs. As fuel costs are passed along to customers on a dollar-for-dollar basis in Kentucky, reductions in Company fuel costs directly benefit customers in the short term and the long term. However, since conservation does not reduce the Companies' fixed costs, nor any other costs recovered through a rate assessed per kWh sold, the Companies' assumption that a 3% conservation effect will result in a 3% bill reduction is only correct in the short term, until the next rate case. At that point, after rates are adjusted for changes in the volume of kWh sold, the only conservation benefits customers will continue to enjoy are fuel cost reductions. As fuel costs are the only actual cost reductions from conservation, only fuel costs should be included in the Companies' ePortal conservation benefit projections.

Q. Thank you for describing the three errors in the Companies' ePortal benefit calculations. Please explain your significant observation.

A. My significant observation is that ePortal conservation is not in the Companies' best economic interest, as it will result in decreased sales. As difficult as achieving the

[21] Case Number 2016-00371. Exh. JPM-1. Page 157.

ePortal benefits projected by the Companies will be, due to the challenges I describe above, the Companies have no economic interest in overcoming these challenges. With no incentive and significant challenges, there is little hope the Companies will secure tens of millions of dollars in associated conservation benefits.

Q. Thank you for explaining the four deficiencies you perceive in the Companies' ePortal benefit projections. Is the impact of these deficiencies on the Companies' benefit projections significant?

A. Yes, they are very significant. In discovery, I asked the Companies to calculate ePortal benefit projections using assumptions I believe are more appropriate. Despite my hesitance to attribute any benefit at all to online usage data availability, but giving the Companies the benefit of doubt, I requested nominal and present value benefit projections on three sets of ePortal assumptions. The benefit projections calculated by the Companies for my scenarios,[22] along with the ePortal benefits originally projected by the Companies,[23] are presented in the table below.

[22] Case Number 2016-00371. Companies' response to AG2-99a, 99b, and 99c.

[23] Case Number 2016-00371. Exh. JPM-1. Page 38.

Scenario	Description	Nominal Benefit	Present Value Benefit
Alvarez Likely	2% portal access, 3% conservation effect, fuel cost benefit only	$5.5 million	$2.2 million
Alvarez Stretch Goal	5% portal access, 3% conservation effect, fuel cost benefit only	$13.8 million	$5.5 million
Alvarez Highly Unlikely	5% portal access, 5% conservation effect, fuel cost benefit only	$23.0 million	$9.2 million
Companies' Original	17% portal access, 3% conservation effect, full bill benefit	$166.3 million	$66.6 million
Reduction, Highly Unlikely vs. Companies' Original:		($143.3 million)	($57.4 million)

Q. Please describe the concept of non-technical loss.

A. Non-technical loss, also known as unaccounted-for energy, is energy that is not billed. Theft and meter malfunction are the largest sources of non-technical loss.[24]

Q. Please describe your concerns regarding the Companies' non-technical loss recovery benefit projections.

[24] Case Number 2016-00317. Exh. JPM-1. Page 35.

A. In the AMS business cases I have reviewed, the benefit projections for non-technical loss (NTL) recovery are among the most variable of any AMS capability. However, of all the AMS business cases I have ever reviewed, the Companies' non-technical loss recovery benefit projections are among the most aggressive. The Companies assume both a high level of non-technical losses to begin with (2%), as well as a high loss recovery rate (36%).[25] In the table below I have summarized the non-technical loss and recovery rate assumptions of recent AMS business cases with publicly-available information.

	State	Docket	Year	Stated Theft & Recovery Assumptions	PV of NTL Recovery (millions)	Recent Year 12 months' electric revenues (billions)[26]
Ameren	IL	12-0244	2012	Theft = 1%; recovery = 25%	19.8	1.683
ConEd	NY	15-E0050	2015	Theft = 1%; recovery = 25%	870.0	8.172
Mass Electric	MA	15-120	2015	Theft = 1.5% Res, 1.0% Comm'l; recovery n/a	168.7	2.522
KU/LG&E	KY	2016-00370/371	2016	NTL = 2%; recovery = 36%	195.3[27]	2.438[28]

[25] Case Number 2016-00371. Exh. JPM-1. Page 158.

[26] SEC Forms 10-K unless otherwise noted. Ameren 2015; Consolidated Edison 2015.

[27] Case Number 2016-00371. Exh. JPM-1. Page 38.

[28] Case Number 2016-00371. Companies' response to PSC DR 1-54 for KU + LG&E, tab "SCH C-1".

Also of significant interest on this issue is a presentation provided by the Companies in discovery to the Association for Community Ministries. This presentation appears to be the final product of a work team, assisted by Accenture Consulting, assigned to develop a business case for smart meters/grid for E-On/US, former owners of KU/LG&E. Dated May 6, 2009, the report estimates the 25-year present value of combined "system losses" and "revenue protection" benefits to be only $28 million.[29] It is notable that just a few years ago, a team investigating the net technical loss recovery benefits from AMS for KU/LG&E found those benefits to be less than 15% of the benefits cited by the Companies in the current AMS business case. I should also point out that "system losses" could mean technical (as opposed to non-technical) losses, making the AMS non-technical loss recovery benefit appear even more aggressive relative to the 2009 E-On/US estimate.

Q. How great an overstatement do you believe is included in the Companies' non-technical loss recovery benefit projection?

A. It is difficult to say. Both the amount of non-technical losses and the ability to recover them are true unknowns, not just for the Companies but for the entire industry. The research cited by the Companies in their non-technical loss recovery benefit indicates that non-technical losses probably range between 1.65% and 2.15% among U.S. electric utilities.[30] A simple average of this range is 1.9% in non-technical losses to

[29] Case Number 2016-00371. Companies' response to ACM DR 1-33. Page 14.

[30] 2008, EPRI, "Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future" p. 1-18.

be recovered, which is only slightly below the Company's assumption of 2% (though 1.9% is well above the 1% to 1.5% cited in recent AMS business cases, as indicated in the chart above). In addition, it seems that a 25% non-technical loss recovery rate is more typical among IOUs than the 36% assumed by the Companies; so splitting the difference with a 30% recovery rate seems appropriate. Using these more conservative assumptions, I compare the nominal and present values I estimated to the Companies' estimates in the table below.

	Nominal Value	**Present Value**
Projections using more conservative assumptions (1.9% theft, 30% recovery)	$362.9 million	$182.9 million
Companies' Benefit Projection (2.0% theft, 36% recovery)	$488.5 million	$195.3 million
Reductions from Companies' benefit projections	($125.6 million)	($12.4 million)

Q. Have you found other AMS benefits projected by the Companies to be overstated?

A. No. Given my experience, I believe the other AMS benefit projections are reasonable. However I point out that certain AMS benefits, such as operating expense reductions and the afore-mentioned non-technical loss recovery, will not result in reduced customer rates without a rate case in which full benefits are reflected in test year accounting records. The Companies can manipulate this opportunity to shareholder advantage and customer detriment. I will return to this issue later in my testimony, as it has significant potential to negatively impact customer benefits from an AMS deployment.

Q. What about the Companies' cost projections? Do you believe those are reasonable?

A. Yes. Given my experience, I believe the Companies' AMS cost projections to be reasonable, with one fairly significant exception. The Companies do not appear to have included profits and other carrying costs on in-service meters which will be retired prematurely in the event of an AMS deployment. Absent a Commission ruling prohibiting the collection of profits and other carrying costs on these stranded assets, the Companies will attempt to recover associated carrying costs and profits in some future rate case. My estimate, based on information provided by the Company in discovery,[31] is that carrying costs and profits on these assets will be $26.3 million on a nominal basis and $15.4 million on a present value basis. I believe these costs should be included in the Companies' AMS cost projections, and I believe the Commission should prohibit recovery of profits and carrying costs on stranded assets if it approves the Companies' AMS proposal against my recommendation. I will return to this issue

[31] PSC 2016-00371. Companies' response to AG DR-2, Q 70. Attachment Tab "Outputs-Recommendations".

later in my testimony. The table below summarizes the adjustment to the Companies' benefit-cost analysis:

	Nominal Value	Present Value
Stranded Asset Carrying Cost Estimate	$26.3 million	$15.4 million
Stranded Asset Carrying Costs Estimated by the Companies	$0.0 million	$0.0 million
Increase in the Companies' cost projections	$26.3 million	$15.4 million

I have one more concern related to the Companies' cost projections. While the cost projections appear reasonable based on my experience, I have observed that actual AMS deployment costs frequently, if not usually, exceed budgets. I have also observed that regulators almost never disallow recovery of AMS cost overruns. I will also return to this issue later in my testimony, as it has the potential to negatively impact customer benefit-cost ratios.

III. THE COMPANIES CAN TAKE ACTIONS TO IMPROVE CUSTOMER BENEFITS

Q. Are there actions the Companies can take to improve the benefits delivered by an AMS deployment?

A. Yes. I believe there are two valuable programs the Companies could implement which provide an opportunity to increase the benefits delivered from an AMS deployment by a significant, but highly variable, amount. I list them below, and will address each individually:

- Make “Peak Time Rebate” a default rate feature available to all residential and small commercial customers and rates, along with performance measures;
- Require a High Bill Alert program, denoted in $, along with performance measures.

Q. What is a “Peak Time Rebate” rate feature?

A. A Peak Time Rebate is a rate feature that rewards customers for reducing energy use during peak demand periods. I recommend Peak Time Rebates be made available to all residential and small commercial customers without any kind of special registration or enrollment; that way, any customer can choose to reduce energy use during peak demand periods, and get paid for doing so, without any requirements or inhibitors.

The Maryland PSC ordered just such an approach in Maryland,[32] and the Massachusetts DPU is currently considering such an approach for IOUs in that state as part of smart meter proceedings. Though the details can vary by utility, here is the general framework for such a rate feature:

1. A peak period (typically 3-6 pm or 4-8 pm weekdays, depending on the characteristics of a system's peak) is established by the Companies.
2. Using hourly smart meter usage data, a baseline for energy use during a representative hot day is established for each customer every few weeks from June through September for the peak period hours.
3. On a limited number of days each summer, generally 10 to 12, the Companies may call a "peak demand event" the day before abnormally high loads or supply shortages are anticipated by the Companies. Mass media and social media are used to alert the communities served by the Companies that the next day will be a peak demand event. Customers who register can also receive a text message, e-mail, or automated phone call notification, though such registration should not be required to qualify for rebates on demonstrated usage reductions during peak demand events.
4. By comparing a customer's usage during the peak demand event hours to a customer's most recent representative hot day baseline, the Companies quantify any statistically significant reductions using algorithms. For customers whose billing periods incorporate more than one peak demand

[32] As an example, see Baltimore Gas & Electric's website at https://www.bge.com/WaystoSave/ForYourHome/Pages/EnergySavingsDays.aspx

event, an average can be employed to improve the accuracy of the reductions quantified by the algorithms.

5. For quantified reductions, measured in kWh reduced, the customer is paid a rebate per kWh via a line item bill credit. This rebate rate per kWh is set at a fairly high amount to reflect the high capacity value of energy reductions during peak demand events. As one might expect, the higher the reward, the greater the response customers will collectively exhibit during a peak demand event. Most research indicates a rebate rate per kWh that is 7-10 multiples of the routine rate per kWh will elicit the intended customer response without skewering the benefit-cost ratio of the program,[33] though the right balance is unique to each IOU and customer population.

Q. Why will the default application of a Peak Time Rebate (PTR) rate feature improve the AMS benefit-cost ratio for customers?

A. Reducing energy use during peak demand periods offers a significant amount of value to all customers, including those who do not conserve during peak demand events, in terms of avoided capacity costs. Research indicates there may also be other sources of value to all customers, including a limited conservation effect (as customers "learn"

[33] Faruqui et al. *Time-Varying and Dynamic Rate Design.* Paper prepared for the Regulatory Assistance Project. Figure 3, "Pilot Impact versus Price Ratio (without Enabling Technology)". July, 2012. Page 29.

that energy use can be modified"),[34] and a reduction in the market price of capacity (the so-called "demand reduction-induced price effect, or DRIPE).[35]

Q. What is the potential impact of a default application of a PTR rate feature to the benefit projections of an AMS deployment?

A. The economic benefits to customers of a default application of a PTR rate feature are potentially large, but highly variable. There are several determinants of PTR rate feature benefit, including the number of customers aware of a peak demand event, the number of those who choose to reduce energy usage during the event, the size of the average usage reduction, and the value the market places on avoided capacity. However, I have completed some informal estimates to provide a rough idea of the potential economic benefit available from the default application of a PTR rate feature under different scenarios, and summarized those estimates in the table below. Note that the assumptions following the table are key drivers of benefit size as well. Also note that my estimates include no estimates of any energy efficiency or DRIPE impacts that might be available from the default application of a PTR rate feature.

Scenario	Customers Reducing	Size of Reduction	Nominal Value, 15 yrs.	Present Value, 15 yrs.
Best Case	20%	20%	$164.1 million	$97.5 million
Likely Case	15%	15%	$70.0 million	$40.9 million
Worst Case	10%	10%	$2.8 million	$0.5 million

[34] King and Delurey. *Efficiency and Demand Response: Twins, Siblings, or Cousins?* Public Utilities Fortnightly. March, 2005.

[35] U.S. Department of Energy. Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them. Report to the U.S. Congress. February, 2006.

Assumptions common to each scenario:

Assumption	Value	Source
Avoided Capacity (per kW-year)	$99.92	Companies' DSM & IRP
Discount Rate for PV (WACC)	6.62%	Companies' GRC
Annual Benefit Escalation	2.20%	Companies' AMS business case
Launch yr. (3) mktg./admin cost	$5.5 mil	OAG
Subsequent yr. mktg./admin cost	$2.75 mil	OAG
Launch yr. (3) % of ann. benefit	75%	OAG
First 2 years' benefit/cost	$0	OAG
Benefit Period (years)	15	OAG

Q. Are there ways for the Companies to increase the size of default PTR benefits?

A. Possibly. As noted above, the value that can be captured for each kW of capacity avoided is a critical determinant of default PTR benefit size. In the PTR benefit estimates calculated above, I utilized the avoided capacity determined by the Company for its Integrated Resource Planning least-cost analyses and Demand-Side Management program benefit-cost analyses ($99.92 per kW-year).[36] Ideally, the value of avoided capacity is something that could, and perhaps should, be determined by an open market rather than the Companies' own analyses. In addition, the market might value capacity more highly than the Companies do, though this is difficult to determine with certainty.

I understand the Companies' service territories border both the PJM and MISO Regional Transmission Organization ("RTO")s' market operating areas. I believe a

[36] Case Number 2016-00317. Companies' response to AG DR 2-79a and 79b.

study to quantify the potential customer benefits to the Companies' membership in one or the other of these markets is warranted. It is my understanding that OAG witness Larry Holloway in his testimony calls for the Commission to require the Companies to conduct a study on whether it would be cost feasible for the Companies to join an RTO. I recommend that this study also include the issue of what market value an RTO would ascribe to the avoided capacity the Companies could achieve by instituting a PTR rate feature for all customers without registration or enrollment.

Q. Is there a relationship between the Companies' Demand Response programs and PTR?

A. Yes. Demand response (DR) is a means to help customers automate the operation of their electric loads, thereby maximizing the benefits from PTR rate features. My understanding is that the Companies have achieved significant levels of DR by offering various programs for residential and commercial customers. For example, residential customers can subscribe to direct load control programs through which the Companies can cycle (turn on and off) customers' air conditioners, electric water heaters, and/or pool pumps at times of system peaks in order to reduce such peaks. On a combined company basis, 58.4% of residential customers are enrolled in at least one of these DR programs.[37] In addition, the companies make load management programs

[37] *See* Case No. 2014-0003, *Joint Application Of Louisville Gas & Electric Co. and Kentucky Utilities Co. for Review, Modification, and Continuation of Existing, And Addition of New, Demand-Side Management and Energy-Efficiency Programs*, Cadmus Study attached as Exhibit MEH-2, and KEMA Study, attached as Exhibit DEH-1.

available to commercial customers.[38] These significant levels of DR penetration represent value to the company and its ratepayers.

In the event the Commission approves the AMS meter CPCN, the companies will be able to *objectively verify* which customers are responding to the need to reduce load, and the amounts of energy savings. This important capability of AMS meters enables the Companies to sell capacity made available through DR into regional transmission organization ("RTO") capacity markets. Many utilities and third-party aggregating firms are in fact selling DR capacity into RTO markets today. My understanding is that LG&E-KU are not members of an RTO such as MISO or PJM, hence the companies would not, by themselves, be able to sell their DR into an RTO capacity market.

As part of the aforementioned PJM/MISO membership study recommended by OAG witness Larry W. Holloway, I recommend that such a study also consider the potential to sell the combined Companies' substantial DR savings into capacity markets. Additionally, that study should consider as an alternative whether it would be possible for the Companies to utilize the services of third-party aggregating companies, which in turn could sell DR-related capacity into an RTO capacity market even if Companies' membership in an RTO does not come to pass.

Q. Do you have other recommendations for the default application of the PTR rate feature?

[38] *Ibid.*

A. Yes. I believe the default application of the PTR rate feature should be accompanied by outcomes-based performance measures, such as kWh reduced during peak demand events. This single measure incorporates how well the Companies would promote the PTR opportunity, advertise peak demand events, educate customers on peak demand event savings opportunities and action steps, and facilitate demand response. Performance measurement is particularly important for PTR programs, as the Companies have no economic incentive for strong PTR performance.

A few other performance measures of interest might be warranted. For example, I would be interesteded~~ing~~ in knowing "annual marketing/admin spend per MWh conserved" during peak demand events as a measure of marketing/admin effectiveness. I would also be interested in an annual cost benefit analysis which compares program spending (including rebates, marketing, and administrative spending) to the value of capacity avoided.

Q. Please describe a High Bill Alert Program

A. A High Bill Alert Program is a customer program designed to help customers manage their electric bills and encourage conservation. Duke Energy Kentucky proposed such a program in its smart meter CPCN,[39] and Southern California Edison's popular "Budget Assistant" is an excellent example already in service.[40] "Budget Assistant" applies algorithms to customers' AMS meter data throughout a month to predict each

[39] Case Number 2016-00152. Direct Pre-filed Testimony of Alexander J. Weintraub, page 10, line 6.

[40] From SCE.com home page, select "Your Home" > "My Account Benefits" > "Budget Assistant".

customer's next bill. These projections are compared to the monthly electric bill budget (in $) set by the customer. When a customer's bill projection amount approaches the customer's electric bill budget, an exception notice is issued to the customer via text, e-mail, or automated phone call (as specified by the customer during registration).

Q. Isn't it true that the Companies current AMS Customer Program offers such a service?

A. Yes and No. The Companies' "My Meter" website, available to AMS Customer Program participants, does offer a usage notification feature, with alert limits chosen by the customer (daily, weekly, or monthly) denoted in kWh. In other words, a customer can register to be notified when his or her kWh threshold is reached. This approach lacks both the bill prediction capability of the Southern California Edison program and the bill amount (in dollars) denomination feature. Without bill prediction and dollar denomination, the Companies' existing usage notification feature has very little customer satisfaction or energy conservation value.

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Q. Do you have other suggestions for a High Bill Alert service?

A. Yes. Like the default application of a PTR rate feature, the Companies have no economic incentive to maximize the conservation effects of a High Bill Alert service. Accordingly, I think performance measures around customer enrollment and marketing effectiveness, similar to those I recommended above for the PTR rate

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feature, should be part of any High Bill Alert program the Commission might order in the event the Commission approves the Companies' AMS proposal for implementation.

Q. What is the potential economic benefit of a High Bill Alert service to customers?

A. I hesitate to develop a benefit estimate based on the conservation value of a High Bill Alert service. To my knowledge there have been no controlled studies measuring the conservation effect of a High Bill Alert program. However, I believe such a program would make the achievement of the "Alvarez Highly Unlikely" conservation benefit estimated in the discussion of ePortal benefits above to be much more likely. One could think of the High Bill Alert service as an insurance policy to help secure the benefits estimated in the "Alvarez Highly Unlikely" ePortal benefit estimate scenario.[41]

[41] See supra, p. 16.

IV. ACTIONS THE COMPANIES MIGHT TAKE WILL NOT LIKELY BE SUFFICIENT TO DELIVER BENEFITS IN EXCESS OF COSTS

Q. Can you summarize your testimony to this point?

A. So far I have provided support for my assertion that the Companies' benefit projections are overstated, including overstatements due to the benefit period time frame (21 years, or about 6 years too long given the useful lives of AMS meters); aggressive ePortal conservation benefit assumptions; and aggressive non-technical loss recovery assumptions. I have also provided support indicating that the Companies' cost projections should be increased by the carrying costs and profits the Companies are likely to request on assets stranded by AMS deployment in future rate cases. Finally, I suggest that the benefits from the proposed AMS deployment could be improved significantly through the default application of a Peak Time Rebate rate feature available to all customers, ideally without any special registration or enrollment requirements.

Q. Please present these adjustments in tabular format.

A. A table which summarizes these adjustments to the Companies' present value benefit-cost analysis is presented in Appendix B to this testimony.

Q. Appendix B only includes adjustments to the Companies' present value benefit-cost ratios. Why have you not addressed the Companies' nominal benefit-cost analyses?

A. The deployment of AMS meters is characterized by large, up-front costs ($350 million in the first five years in this instance)[42] and small economic benefits that accrue over longer periods of time (15 years as I recommend, or 21 years as the Companies recommend in their business case). Nominal value analyses do not adjust for changes in the value of money over time. Just as a dollar in hand today is worth more than a dollar 15 years from now, a benefit received 15 years from now should be valued at a much smaller amount than a benefit received today. Assigning nominal value (today's dollars) to benefits which won't be realized for years into the future is yet another way to artificially improve the results of a benefit-cost analysis.

By contrast, present value analyses adjust the value of money over time; present value analyses reflect the reality that a benefit received 15 years from now is worth far less than a benefit received today. As a result, present value analyses are more appropriate and relevant for any investment with large up-front expenditures and smaller benefits that accrue over time, which is precisely the situation with AMS deployments.

Q. So what do you conclude about the Companies' AMS proposal?

[42] Case Number 2016-00371. Exh. JPM-1. Page 39.

A. Even if the Company were to take the actions recommended in the preceding section of my testimony, including the default application of PTR rate features, I do not think it is likely the AMS deployment will deliver benefits to customers in excess of costs. On this basis, I recommend the Commission reject the Companies' request to deploy AMS.

V. IN THE EVENT IT APPROVES THE AMS PROPOSAL, THE COMMISSION CAN TAKE ACTION TO REDUCE ECONOMIC RISKS TO CUSTOMERS

Q. The Commission may take factors other than economic benefit-cost analyses into account, and could approve the Companies' proposed AMS deployment despite your recommendation it be rejected. In this event, do you have any recommendations which would reduce customers' economic risks?

A. Yes. The program recommendations I make above to increase the benefits from an AMS deployment would certainly stand in the event the Commission approves the Companies' AMS proposals, and I suggest the Commission make these conditional requirements of AMS approval:

- The Companies are to offer peak time rebates to all customers, without enrollment or registration requirements, and an associated performance measurement and reporting program;
- The Companies are to offer a High Bill Alert program, and an associated performance measurement and reporting program;
- Companies are to participate in a study to evaluate the customer benefits of the Companies' membership in the PJM or MISO market operating areas, as discussed above.

These approval requirements will all demand the Companies' active co-operation, participation, and interest to implement. However, there are many actions the Commission could take on its own to reduce the economic risks to customers of an

AMS deployment. I will discuss each of the following conditions, recommended in the event the Commission approves the AMS proposal, in the final section of my testimony:

- A mechanism which guarantees benefits will be reflected in Customer rates to the extents and within timeframes projected by Companies in the AMS business case;
- A mechanism which limits the recovery of any cost overruns from customers;
- A prohibition against the recovery of carrying costs and profits on assets removed from service to make way for AMS assets;
- A requirement that AMS-related customer satisfaction programs be implemented, including tariffed, cost-based AMS meter opt-out fees and Green Button's "Connect My Data" standard.

Q. Why do you feel AMS approval should be conditioned on benefit guarantees?

A. I have made it clear throughout this testimony that several of the Companies' benefit projections will be almost impossible to achieve. I have also pointed out that, contrary to capital investment, the Companies have no incentive to overcome challenges to secure projected benefits. I believe these issues easily justify the need for performance guarantees in the event the Commission approves the AMS deployment.

Q. Please describe a mechanism which would guarantee that benefits will be reflected in Customer rates to the extents and within timeframes projected by the Companies in their AMS business case.

A. Some of the largest benefits the Companies project in their AMS business case will not find their way into customers' pockets unless a rate case is conducted, using a test year in which such benefits are reflected in accounting records. Since the Companies are in charge of both the timing of benefit delivery and the timing of rate cases, the Companies can "time" both to the benefit of shareholders and the detriment of customers.

Q. Please explain.

A. When it comes to operating expense reductions, a utility can simply avoid laying off employees or cancelling contract work until after a test year. When it comes to non-technical loss recovery, a utility can simply wait to implement theft detection or metering error detection processes until after a test year. By delaying such actions, the old, "pre-deployment" circumstances and costs are included in test year accounting records and reflected in customer rates determined via that test year's data. However, once rates are set, and recovery of these costs from ratepayers is assured, the utility can simply execute the cost-reduction and non-technical loss recovery plans *after* the test year. In this manner shareholders, not customers, reap the operating expense reduction and non-technical loss recovery benefits of the AMS investments (not to mention associated profits) for which customers are paying in rates.

To be sure, this situation is rectified in some future rate case, when a test year which reflects lower levels of operating expenses and higher sales volumes from AMS-related capabilities is used to calculate new customer rates. Unfortunately, absent a PSC order, the Companies determine rate case timing. When costs are increasing/revenues decreasing, utilities file a rate case, adjusting rates higher to compensate. When costs are decreasing/revenues increasing, for example from an AMS deployment, utilities will delay filing a rate case. That's because to do so would convert economic benefits enjoyed by shareholders into economic benefits enjoyed by ratepayers via rate reductions.~~.~~ If that future rate case were delayed for 10 years, customers would fail to receive these benefits in the form of rate reductions for 10 years. During this period, shareholders win at customers' expense. This opportunity to "time" AMS benefit delivery and rate cases is not a reasonable proposition, and I recommend the Commission consider some type of mechanism designed to return, on a timelier basis, the economic benefits of any AMS proposal the Commission might approve.

Q. Can you provide a hypothetical example to illustrate?

A. Yes. Assume for purposes of illustration the Companies process a rate case in AMS year 4 as the test year. In AMS year 4, assume that the massive capital investment in AMS meters and systems is complete, but that the non-technical loss recovery capabilities have yet to be implemented. The rates calculated using such a test year would reflect capital cost recovery, and a rate of return on capital, but not the revenue benefits associated with non-technical loss recovery.

Now assume the non-technical loss recovery plans are implemented in year 5, after the test year. Assume the Companies increase their recovery of non-technical losses in the amounts and years described below:

AMS Plan Year	NTL Recovery Improvement
1	$0
2	0
3	0
4	0
5	3,000,000
6	3,250,000
7	3,500,000
8	3,750,000
9	4,000,000
10	4,250,000
11	4,500,000
12	4,750,000
13	5,000,000

Assuming no rate cases are processed from year 5 through year 13, the Companies' shareholders will secure $36 million in profits above and beyond the rate of return authorized by the Commission in the year 4 rate case. If a rate case is held in year 14, customers will finally begin receiving the benefits promised to them in the IOU's AMS business case. However, this is not the end of the story. What if the Companies' AMS business case indicated they would deliver $6,500,000 in non-technical loss recovery benefits in year 13 of their AMS plan? In this hypothetical example, customers will have missed out of 9 years' worth of benefits due to rate case timing, but are still short $1,500,000 in benefits anticipated in the Companies' AMS business case but not delivered.

Q. Do you offer any related recommendation?

A. Yes. To address both the rate case timing issue and the failure to deliver on AMS business case benefits, regulators in Oklahoma[43] and Ohio[44] specified that revenue requirements be reduced by the amount of the benefits projected by the IOUs in their AMS their benefit-cost analyses:

AMS Plan Year	Projected Benefit	Revenue Requirement Adjustment
1	$0	$0
2	0	0
3	4,000,000	(4,000,000)
4	4,250,000	(4,250,000)
5	4,500,000	(4,500,000)
6	4,750,000	(4,750,000)
7	5,000,000	(5,000,000)
8	5,250,000	(5,250,000)
9	5,500,000	(5,500,000)
10	5,750,000	(5,750,000)
11	6,000,000	(6,000,000)
12	6,250,000	(6,250,000)
13	6,500,000	(6,500,000)

I've found this approach delivers several benefits to customers. First, it delivers economic benefits to customers – benefits which they are paying to obtain through the AMS-related rate increases – without having to wait for a rate case to recognize benefits in rates. Second, it holds the Companies accountable for delivering the size of benefits it projects in its benefit cost-analysis. Third, it holds the Companies accountable for the speed at which benefits are to be delivered. And finally, it provides an economic incentive for the Companies to secure economic benefits of the size and speed indicated in their AMS business case, as described below.

[43] Oklahoma Commerce Commission. Order 576595 in Cause PUD 201000029. Finding of Fact 12. July 1,2010. Page 18.

[44] Public Utilities Commission of Ohio. Stipulation and Recommendation in Case 10-2326-GE-RDR. Section II. February 24, 2012. Pages 5-10.

Q. Please explain how this mechanism provides the Companies with an economic incentive to secure the benefits projected in the AMS business case.

A. In my experience, it can be difficult for an IOU to secure benefits from AMS-related investments. Operating policies and processes must be changed, employees must be trained, and policy and process changes must be enforced. In some cases, organizational changes are required. Innovation is required to identify opportunities to employ newly-available data in ways that improve service or reduce costs. If there is no motivation to maximize benefits, and no oversight to ensure projected benefits are secured, it is entirely possible that organizational and operational challenges can prevent projected benefits from being maximized or secured.

Therefore, I believe "IOU motivation" to be another benefit associated with the implementation of the mechanism described above. If the Companies secure benefits greater than projected, or secure them earlier than projected, shareholders benefit; if the Companies fail to secure the size of benefits projected, or fail to secure them in the timeframes projected, shareholders pay. I believe the recommended mechanism therefore provides the necessary incentives for the Companies to overcome the organizational and operational challenges associated with securing AMS-related benefits for operating expense reductions and NTL recovery improvements. In addition, I believe post-deployment benefit measurement is another tool the Commission should use in the event it approves the Companies' AMS proposal.

Q. Why do you believe post-deployment benefit measurement should be used in addition to your recommended rate-case timing mechanism?

A. The recommended mechanism is only intended to secure for customers those AMS-related economic benefits that would not be reflected in rate reductions without a rate case. As described above, these are operating expense reduction and NTL recovery improvement benefits. Other AMS-related benefits, such as PTR rate features or High Bill Alert conservation, are reflected on customers' bills without a rate case. Benefit assurances cannot readily be delivered using accounting mechanisms for these types of AMS-related benefits; accordingly, the post-deployment measurements described in the PTR and High Bill Alert discussions above are suggested.

Q. Have you prepared a schedule of recommended revenue requirement adjustments by year, assuming the Commission agrees with your assessment of the need for a benefit assurance mechanism?

A. Yes. Confidential Appendix C offers a schedule of recommended revenue requirement adjustments by year based on the Companies' confidential business case provided in discovery. If the Commission were to authorize the revenue requirement adjustments in this schedule, shareholders, and not ratepayers, would bear the risk of any AMS business case benefit projections not achieved by the Companies.

Q. Why do you feel AMS approval should be conditioned on cost overrun recovery limits?

A. In my experience, grid modernization cost overruns are much more likely than under-budget performance. In the only two independent evaluations of smart meter deployment costs of which I am aware, including one evaluation I led,[45] and one led by the California Office of Ratepayer Advocacy,[46] both demonstrated significantly higher capital and operating costs than anticipated. I've noted several reactions in response to cost overruns:

- Capabilities or deployment scope are curtailed (generally resulting in lower benefits for customers);
- Customer rates are increased by an amount greater than originally approved;
- Cost overruns are disallowed by a regulator.

Cost overrun disallowance by a regulator is rare in cases of grid modernization. I know of only one case in which recovery of grid modernization cost overruns from customers was denied.[47] It is difficult to make a showing that cost overruns associated with CPCN investments were imprudent based on what a reasonable individual knew or should have known. In my experience cost overruns are much more likely to result in customer benefit reductions, unanticipated rate increases, or both, rather than disallowances. As a result, ratepayers are essentially "on the hook" for 100% of the risk of cost overruns.

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[45] Alvarez et al. *SmartGridCity™ Demonstration Project Evaluation Summary*. Colorado PUC11A-1001E. Exhibit MGL-1. Filed December 14, 2011.

[46] Hieta, Kao, and Roberts. *Case Study of Smart Meter System Deployment*. California Office of Ratepayer Advocacy. March, 2012.

[47] Colorado Public Utilities Commission. Decision R13-0096 in Proceeding 11A-1001E.

Q. Do you offer any related recommendation?

A. Yes. I think some sort of cost risk-sharing mechanism is appropriate in the event the Commission approves the Companies' AMS proposal. One simple and effective mechanism would be to limit the Companies' recovery of any overruns in excess of projected costs to 50% of such amounts. In this way cost overrun risk is split 50:50 between customers and shareholders.

Q. Has this recommendation been implemented in any other AMS projects?

A. I am not aware of any other AMS projects in which regulators have implemented such a condition. However, this does not indicate such a condition is inappropriate.

Q. Please explain why you feel a prohibition against the recovery of carrying costs and profits on undepreciated assets removed from service to make way for AMS is appropriate

A. The Companies are proposing $320 million in capital investment in their AMS plan, on which they will earn hundreds of millions of dollars in profit over the next 15 years. As described earlier, in addition to the $39 million in meter book value to be written off as existing meters are replaced, the Companies will likely request costs and profits on these stranded assets amounting to $26 million ($15 million in present value). The rate increases associated with the AMS proposal and stranded cost recovery will be difficult for many customers to pay, particularly considering the challenges to securing benefits described throughout this testimony.

Recalling my earlier testimony regarding the shorter useful life of AMS meters, it is conceivable that the companies' customers will be paying for as many as three or four meters at once: 1.) the retired meters still being written off; 2.) AMS meters; and 3.) replacements for AMS meters that fail before the end of the 21-year useful life assumed by the Companies. In addition, LG&E gas customers will be paying for 54,000 new gas meters[48] and 322,000 automated gas meter-reading indices. To ask customers to pay for profits and carrying costs on what could amount to three or even four meters simultaneously is unfair, unjust, and unreasonable.

Q. Do you have any related recommendation?

A. Yes. I recommend the Commission expressly prohibit the recovery of profits and carrying costs on all assets stranded by any AMS deployment the Commission may approve. In addition, to mitigate ratepayer bill shock, and to comport with the principle of gradualism, I recommend the write-down of this regulatory asset should be conducted over 15 years per PSC precedent rather than the 5 years requested by the Companies. And finally, I suggest these issues be resolved now, in this case, rather than waiting for some future rate case as the Companies are likely to suggest. Resolving these stranded asset issues now provides more certainty and more complete information for making a decision on the Companies' AMS proposal.

Q. **Please describe the approval conditions you would recommend for AMS-related customer satisfaction programs.**

[48] Case Number 2016-00317. Direct Pre-filed testimony of John P. Malloy. Page 16.

A. Should the Commission elect to approve the Companies' AMS proposal, I believe it is reasonable to require a few customer satisfaction accommodations which should entail little cost: AMS meter opt-out with tariffed AMS meter opt-out fees, and compliance with the Green Button Connect My Data standard.

Q. Please explain why you believe customers deserve an AMS meter opt-out alternative.

A. While many of us cannot conceive of a world without cell phones, wireless data networks, and microwave ovens, there is a subset of the population who actively avoid these electro-magnetic frequency-emitting devices. These people legitimately fear the health impacts of such emissions, and it is not inconceivable that hyper-sensitivity to such emissions exist in a very small percentage of the general population. Other consumers have concerns about wireless data security and privacy. For people in these situations, who are willing and able to pay for the incremental cost of a meter which does not communicate wirelessly, it seems reasonable that such an option be made available.

I am not suggesting that the option be subsidized by other ratepayers, and agree that cost-based fees, both initial and ongoing, are appropriate. But to not offer any alternative to AMS meters does not seem reasonable. If the Commission approves the Companies' AMS proposal, I recommend a condition be established which mandates a tariffed, cost-based, fee schedule for customers who elect not to have a wireless-communicating AMS meter attached to their residence.

Q. Please explain the need for compliance with the Green Button Connect My Data Standard.

A. The Green Button "Download My Data" standard harmonizes how consumers download energy usage data in the same format from utility to utility. It's a good start, and dozens of large US IOUs, from Pacific Gas & Electric to Baltimore Gas & Electric, offer it to their customers.[49] Increasingly, the Green Button standard is the link to a growing ecosystem of application developers and service providers who wish to make money by helping consumers save money on their energy bills. These may be reasons enough for the Commission to require Green Button Download My Data compliance from the Companies as an AMS approval condition, but even more power is available from the Green Button's "Connect My Data" standard.[50]

The Connect My Data standard was developed to allow a customer to specify the service providers to which the customer wishes to authorize ongoing access to his or her energy usage data without manual intervention. This is a big advance from the Companies' "My Meter" portal or even the Green Button Download My Data standard. Connect My Data also addresses the protocols by which authorized service providers can access their customers' energy use data in a secure, automated manner from IOUs, and this is important for high-volume execution. In a future with PTR rate features and other sorts of dynamic pricing, Connect My Data compliance is likely to enlarge peak demand event participation, simplify peak demand event usage

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[49] A list of US utilities which offer, or which have committed to implement, the Green Button Download My Data standard can be found at https://energy.gov/data/green-button.

[50] Green Button Connect My Data standard. Available from the Green Button Alliance. www.greenbuttonalliance.org.

reductions for customers, and increase PTR-related value creation and AMS benefits. The Connect My Data standard lays the foundation for third-party participation in energy management. As such, it is not something the Companies are likely to pursue voluntarily, and is therefore a worthwhile approval condition for the Companies' AMS proposal.

VI. SUMMARY AND CONCLUSION

Q. Would you care to summarize your testimony?

A. I recommend the Commission reject the Companies' proposal to deploy AMS. The benefit-cost ratio is —unlikely to be favorable for customers, and therefore unreasonable, due to multiple business case issues, including

- Use of a 21-year benefit period when useful meter life is 15 years;
- Multiple ePortal benefit assumptions are erroneous;
- Non-technical loss recovery benefit assumptions are overly-aggressive;
- Profit and carrying costs on stranded assets are not included.

The Companies can take action to increase benefits, including:

- Default application of the peak time rebate rate feature
- Consideration of PJM or MISO membership
- Development of a High Bill Alert program

Unfortunately, these actions are unlikely to deliver a favorable benefit-cost ratio -for customers. Considering all of the above, I estimate about $0.80 in benefit for every $1 in spending, resulting in my recommendation to reject the Companies' AMS proposal.

If it elects to approve the Companies' AMS proposal despite these issues, the Commission can take action to reduce the economic risks faced by customers, including:

- Instituting a benefit guarantee mechanism
- Limiting customer exposure to cost overrun risk
- Prohibiting profits and carrying charges on assets stranded by AMS
- Requiring customer satisfaction efforts such as a tariffed AMS opt-out rate and "Connect My Data" compliance (secure, ongoing third party usage data access).

Q. Do you have any concluding thoughts?

A. Yes. As discussed in my introduction to this testimony, I believe AMS deployments have the potential to deliver a favorable, or at least break-even, benefit-cost ratio for customers. However, I also believe a demanding combination of utility motivations, customer engagement, situational characteristics, and regulatory oversight is required to deliver this outcome. The Companies' business plan does not convince me that this demanding combination is sufficiently present to provide a break-even or better outcome for customers. I hope the Commission appreciates my sobering and pragmatic perspective, and I thank the Commission in advance for considering this testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A: CURRICULUM VITAE OF PAUL ALVAREZ

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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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 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 and environmental advocates, regulators, associations, and suppliers.

Research Projects, Thought Leadership, Regulatory Appearances

Arguments to Reject Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Arguments to Reject Westar Energy's Proposal to Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Best Practices in Grid Modernization Capability Optimization: Visioning, Strategic Planning, and New Capability Portfolio Management. Top-5 US utility; client confidential. 2014.

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. Filed December 14, 2011 as Exhibit MGL-1. Report dated October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. First edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 327 pages. 2014.

Noteworthy Publications

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014. Republished in the ICER Chronicle, 3rd Edition, March, 2015.

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.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Notable Presentations

NASUCA Mid-Year Meeting. *Utility Evaluator™ Software: Benchmarking Distribution Utility Performance Using Publicly-Available Data.* New Orleans, LA. June 7, 2016.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Keynote. Toronto, Canada. January 23, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012.

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25, 2012.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23, 2012.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis. November 13, 2011.

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 of Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Accounting, Finance, Information Systems, and International Business.

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

Certifications

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

APPENDIX B: SUMMARY OF BENEFIT-COST ANALYSIS ADJUSTMENTS

	Companies' Present Value	OAG Adjustments	OAG Present Value
(Costs)			
Total Project Costs (Capital)	(299.0)		(299.0)
Total Project Costs (O&M)	(23.1)	-	(23.1)
Total Project Costs	(322.1)	-	(322.1)
Total Recurring Costs (Capital)	(11.3)		(11.3)
Total Recurring Costs (O&M)	(50.7)	-	(50.7)
Total Recurring Costs	(62.0)	-	(62.0)
Meter Retirement	(3.8)	(15.4)	(19.2)
Total Lifecycle Costs	(387.9)	(15.4)	(403.3)
Benefits			
Operational Savings	156.2	-	156.2
Recovery of Non-Technical Losses	195.3	(12.4)	182.9
ePortal Benefit	66.6	(57.4)	9.2
Change from 20 year life to 15	-	(74.7)	(74.7)
Total Lifecycle Benefits	418.1	(144.5)	273.6
Net Benefits (Costs)	30.2	(159.9)	(129.7)
Benefit-Cost Ratio:	**1.1**		**0.7**
Additional Benefit: PTR (Likely Case)	-	40.9	40.9
Adjusted Net Benefits (costs)	30.2	(119.0)	(88.8)
Adjusted Benefit-Cost Ratio			**0.8**

CONFIDENTIAL APPENDIX C: SCHEDULE OF REVENUE REQUIREMENT ADJUSTMENTS BASED ON COMPANIES' AMS BUSINESS CASE

Recommended, AMS-related Revenue Requirement Adjustments by Year to Guarantee O&M and Revenue Enhancement benefits.

Does not include projected savings from avoiced capital ("Avoided Meter Costs" + "Avoided and Deferred IT Costs") or conservation ("ePortal"). These benefits cannot be guaranteed through accounting processes and should be measured directly.

($ in millions)	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34	'35	'36	'37	'38	'39
Adjusment to LG&E Electric Revenue	9.878	10.118	10.572	10.844	11.173	11.513	11.864	12.225	12.598	12.983	13.380	13.790	14.213	14.649	15.099	15.564	16.043	16.538	17.049	17.576	18.120
Adjusment to LG&E Gas Revenue	2.119	2.337	2.390	2.441	2.494	2.547	2.602	2.658	2.715	2.773	2.832	2.893	2.955	3.018	3.083	3.149	3.217	3.285	3.356	3.428	3.501
Adjustment to KU Revenue	9.791	14.503	15.014	15.526	16.040	16.573	17.124	17.695	18.286	18.898	19.533	20.190	20.870	21.576	22.306	23.063	23.847	24.660	25.502	26.375	27.279
Adjustment to ODP Revenue	0.224	1.242	1.260	1.321	1.367	1.416	1.466	1.518	1.572	1.629	1.688	1.749	1.813	1.880	1.949	2.022	2.097	2.176	2.258	2.344	2.433
TOTAL COMPANIES Revenue Adjustments	22.013	28.200	29.235	30.133	31.075	32.048	33.055	34.095	35.171	36.283	37.433	38.622	39.851	41.123	42.438	43.798	45.204	46.660	48.165	49.722	51.333

APPENDIX C PUBLIC VERSION: SCHEDULE OF REVENUE REQUIREMENT ADJUSTMENTS BASED ON COMPANIES' AMS BUSINESS CASE

Recommended, AMS-related Revenue Requirement Adjustments by Year to Guarantee O&M and Revenue Enhancement benefits.

Does not include projected savings from avoiced capital ("Avoided Meter Costs" + "Avoided and Deferred IT Costs") or conservation ("ePortal"). These benefits cannot be guaranteed through accounting processes and should be measured directly.

($ in millions)	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34	'35	'36	'37	'38	'39
Adjusment to LG&E Electric Revenue	This data is from the Companies' confidential resposne to 2016-00371 PSC 2-63. Not available without a signed confidentiality agreement.																				
Adjusment to LG&E Gas Revenue																					
Adjustment to KU Revenue																					
Adjustment to ODP Revenue																					
TOTAL COMPANIES Revenue Adjustments																					