COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR FULL DEPLOYMENT OF ADVANCED METERING SYSTEMS	**)))))))**	**CASE NO. 2018-00005**

TESTIMONY OF
JOHN P. MALLOY
VICE PRESIDENT, GAS DISTRIBUTION
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 10, 2018

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Q. Please state your name, position and business address.

A. My name is John P. Malloy. I am Vice President of Gas Distribution for Louisville Gas and Electric Company ("LG&E"), which is the sister utility of Kentucky Utilities Company ("KU") (collectively, the "Companies"). I am an employee of LG&E and KU Services Company. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. A complete statement of my work experience and education is contained in the Appendix A attached hereto.

Q. Have you previously testified before this Commission?

A. Yes, I have filed testimony with this Commission on several occasions. Most recently I submitted direct and rebuttal testimony in the Companies' 2016 base-rate cases to support the Companies' first request for certificates of public convenience and necessity ("CPCNs") for full deployment of Advanced Metering Systems ("AMS") in the Companies' Kentucky service territories.[1]

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit JPM-1 Electric and Gas Advanced Metering Systems Business Case for Louisville Gas and Electric Company and Kentucky Utilities Company

Q. What are the purposes of your testimony?

[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Testimony of John P. Malloy (Nov. 26, 2016); Case No. 2016-00370, Rebuttal Testimony of John P. Malloy (Apr. 10, 2017); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Testimony of John P. Malloy (Nov. 26, 2016); Case No. 2016-00371, Rebuttal Testimony of John P. Malloy (Apr. 10, 2017).

A. My testimony has three purposes. First, I explain why the Companies are seeking Commission approval for full AMS deployment now. Second, I describe the current state of advanced metering deployments nationally and in Kentucky to demonstrate that, far from being unique or an outlier, the Companies' proposed full deployment of AMS across its Kentucky service territories is in line with a years-long trend across the United States and in the Commonwealth. Third, I provide support for the Companies' proposed full deployment of AMS, including providing cost-benefit and technical information necessary to support the Companies' requests for certificates of public convenience and necessity ("CPCNs"), one per Company, for the proposed AMS deployment.

I. FULLY DEPLOYING AMS NOW WILL PROVIDE BENEFITS TO CUSTOMERS AND ENABLE THE COMPANIES TO OFFER NEW RATES AND SERVICES

Q. Briefly, what are the benefits of full AMS deployment?

A. The Companies' analysis continues to show that fully deploying AMS will provide net benefits to customers by creating net cost savings, increased distribution grid efficiencies and performance, and empowering the Companies with data potentially to offer new rates and services in the future. More specifically, the Companies' analysis projects that full AMS deployment will result in net savings of $483 million (nominal) and $28.5 million (net present value (NPV)) between 2018 and 2040.[2] These net savings result from operational savings (e.g., reduced meter reading

[2] Please note that these values were calculated prior to the recent revision in the federal corporate income tax rate. The Companies are currently working to revise these calculations to account for the new tax rate and will file them in this proceeding as soon as reasonably possible, and no later than January 31, 2018. Preliminary calculations indicate the effect of the new tax rate will be to slightly increase the proposed deployment's net benefits on a net present value basis.

expense), improved identification and attribution of non-technical losses (i.e., losses resulting from theft of service and malfunctioning meters), and reduced energy consumption by customers as they become more aware of their consumption patterns by reviewing the granular consumption information AMS provides and seeking to increase their energy-efficiency measures and behaviors.

Regarding increased distribution grid efficiencies and performance, AMS data could be used for transformer load management, which may allow some distribution transformer failures to be predicted earlier, with preemptive repair or replacement of such transformers reducing outage durations and avoiding the additional cost of "emergency" replacements. AMS can also proactively report when power outages have been detected for individual meters, help the Companies identify the location and extent of outages, supporting more rapid and effective coordination of restoration efforts. Finally, AMS can reduce the number of instances in which a crew is dispatched to a reported outage, but arrives on-site to find utility-responsible services operating properly.

In addition, data from AMS meters will allow the Companies to consider and propose additional rate and service offerings, including various kinds of time-of-day rate structures and a variety of service-related notifications and updates that could aid customers in understanding and modifying their energy consumption patterns. Although the Companies are not proposing any new rates in this proceeding, and are not committing to do so, they anticipate that data provided by AMS will help the Companies better formulate rates and rate structures in the future.

Q. Why are the Companies seeking approval for full AMS deployment now?

A. As Rick E. Lovekamp describes in his testimony, the Companies first proposed full AMS deployment in their 2016 base-rate cases, but agreed in the First Stipulation in those cases to withdraw their request and initiate an AMS Collaborative involving the Companies and all interested parties to the rate cases to discuss and to seek to address any concerns about AMS.[3] David E. Huff describes the work of the AMS Collaborative in his testimony. That work is now complete, though the group has agreed to continue meeting after AMS is deployed to address opportunities or concerns that might arise post-deployment.

Now that the AMS Collaborative has completed its work, the Companies desire to propose again, and to seek CPCN authority for, full AMS deployment. As I describe below, advanced metering is now the norm, not the outlier, in metering technology in the United States, and is becoming the norm in Kentucky, as well. The Companies believe it is now appropriate for their customers to join the millions of utility customers across the country and the Commonwealth already enjoying the benefits of AMS.

II. ADVANCED METERING DEPLOYMENTS CONTINUE TO GROW NATIONALLY AND IN KENTUCKY

Q. Please describe the current state of advanced metering deployments in the United States.

A. Advanced metering, i.e., electronic metering capable of two-way communication, is clearly now the dominant meter technology in the United States. According to the

[3] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017).

U.S. Energy Information Administration's *Electric Power Annual 2016* (published in December 2017), advanced metering infrastructure ("AMI") meters are the single most widely deployed meter type in the United States as compared to automated meter reading ("AMR") meters, which are the second-most deployed, and standard (non-AMI and non-AMR) meters.[4] More specifically, EIA reports that in 2016, of the 151.3 million total meters deployed in the U.S., 70.8 million (46.8%) were AMI meters, 46.8 million (30.9%) were AMR meters, and only 33.7 million (22.3%) were standard meters.[5] Indeed, of the 13.3 million net new meters installed nationwide between 2013 and 2016, all of them were AMI meters: AMI meters increased from 53.3 million in 2013 to 70.8 million meters in 2016 (net increase of 17.5 million), while AMR meters decreased from 47.3 million in 2013 to 46.8 million in 2016 (net decrease of 0.5 million) and standard meters decreased from 37.4 million in 2013 to 33.7 million in 2016 (net decrease of 3.7 million).[6] In short, advanced metering of the kind the Companies proposed in their 2016 base-rate cases and propose again here is clearly the dominant trend in electric utility metering, not an outlier or rarity.

Q. What is the status of advanced metering deployments in Kentucky?

A. Although advanced meters are not yet the majority of electric meters deployed in Kentucky today, they are trending in that direction. Today, of the more than 775,000 customers served by cooperatives and municipal electric utilities in Kentucky,[7] more

[4] Electric Power Annual 2016 at Table 10.10, available at https://www.eia.gov/electricity/annual/pdf/epa.pdf (accessed Dec. 7, 2017).
[5] *Id.*
[6] *Id.*
[7] Kentucky Energy and Environment Cabinet, Department of Energy Development and Independence, *Kentucky Energy Profile* at page 20, 6th Ed. 2017, available at http://energy.ky.gov/Documents/2016%20Kentucky%20Energy%20Profile.pdf (accessed Nov. 6, 2017).

than 535,000—nearly 70% of such customers—are served by advanced meters.[8] In addition, more than 39,000 customers of investor-owned utilities also have advanced meters,[9] meaning that over 25% of Kentucky's 2.2 million electric customers currently have advanced meters.[10] The Commission's recent approval of Duke Energy Kentucky's request to deploy approximately 143,000 electric AMI meters, approximately 82,500 gas AMI modules for its combination customers, and approximately 20,500 gas AMR modules for its gas-only customers will further significantly increase advanced meter installations in Kentucky.[11] Even more recently, Grayson Rural Electric Cooperative Corporation requested Commission approval to deploy over 15,000 AMI meters and supporting infrastructure in its service territory.[12] Therefore, the status of advanced metering in Kentucky is that it is already broadly deployed and is continuing to expand. It is appropriate that it now expand to the Companies' service territories, as well.

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[8] The Edison Foundation, Institute for Electric Innovation, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* at page 15, October 2016, available at http://www.edisonfoundation.net/iei/publications/Documents/Final%20Electric%20Company%20Smart%20Meter%20Deployments-%20Foundation%20for%20A%20Smart%20Energy%20Grid.pdf (accessed Nov. 6, 2017).

[9] *Id.*

[10] *Kentucky Energy Profile* at page 20.

[11] *In the Matter of: Application of Duke Energy Kentucky, Inc. for (1) a Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief*, Case No. 2016-00152, Order (May 25, 2017).

[12] *In the Matter of: the Application of Grayson Rural Electric Cooperative Corporation of Grayson, Kentucky, for Commission Approval Pursuant to KRS 807 [sic], KRS 5:0001 [sic], and KRS 278.020 for a Certificate of Public Convenience and Necessity to Install an Advanced Metering Infrastructure (AMI) System*, Case No. 2017-00419, Application (Oct. 24, 2017).

III. FULL DEPLOYMENT OF ADVANCED METERING SYSTEMS (AMS) WILL PROVIDE SIGNIFICANT BENEFITS TO CUSTOMERS

Q. What are the fundamental differences between the Companies' full AMS deployment proposal in this proceeding and the Companies' proposal for full deployment of AMS made in the Companies' 2016 base-rate cases?

A. There are no fundamental differences between the deployment proposals, though the Companies are now proposing to permit customers to opt out of AMS, which Mr. Huff addresses in his testimony. Therefore, much of what the Commission will see in my testimony and in Exhibit JPM-1 to my testimony, *Electric and Gas Advanced Metering Systems Business Case for Louisville Gas and Electric Company and Kentucky Utilities Company* ("AMS Business Case"), will be familiar. That is not an accident: The Companies believe their 2016 proposal was sound and would have provided significant benefits for customers. Therefore, with the exception of permitting customers to opt out of AMS, the Companies have not fundamentally altered the proposal they are making now, which still will provide benefits to customers. As I further explain in my testimony and as discussed in the AMS Business Case, the Companies' more refined AMS proposal in this proceeding is projected to provide net benefits of $483 million (nominal; $28.5 million net present value (NPV) to 2018) from 2018 through 2040. Those net benefits are essentially identical to the net benefits supporting the Companies' 2016 AMS proposal (almost $470 million nominal; $30.2 million NPV to 2016).[13]

[13] Case No. 2016-00370, Testimony of John P. Malloy at 17 (Nov. 23, 3016); Case No. 2016-00371, Testimony of John P. Malloy at 17 (Nov. 23, 3016).

Q. Does the lack of fundamental changes between the Companies' 2016 and current AMS proposals indicate the proposal is stale or out of date?

A. Not at all; rather, it reflects the quality and seriousness of the Companies' 2016 proposal. Also, it is a positive sign of the maturity of AMS technology that it is not changing such that it requires the Companies to propose fundamentally different AMS deployments from one year to the next.

Q. If the projected net benefits of AMS deployment have stayed essentially the same since the Companies initially proposed full AMS deployment in late 2016, could customers be denied potential benefits by further delaying deployment?

A. Yes. If anything, the Companies are more certain now that delaying deployment could deny customers potential benefits. Since the Companies withdrew their previous request for full AMS deployment, they have revisited, refined, and confirmed each and every cost and benefit estimate and assumption. (Details concerning those refinements are contained in Exhibit DEH-5 to Mr. Huff's testimony and attachment A-5 to Exhibit JPM-1 to my testimony.) The Companies' work in the intervening year has confirmed that there are good reasons to believe full AMS deployment will provide quantifiable savings and benefits, as well as qualitative benefits in the form of increased customer empowerment through increased access to more granular usage data, improved distribution grid performance, and potentially increased rate and service offerings. Delaying full AMS deployment will only delay the realization of those potential cost, reliability, and service benefits for customers.

And it is not necessarily true that the net benefits of full AMS deployment will remain essentially unchanged if delay continues. A large percentage of the

Companies' estimated cost of full AMS deployment—more precisely, 41% of such costs—are labor-related. Such costs could increase more rapidly than the corresponding savings might increase, resulting in a decrease in net benefits. Therefore, it is not at all clear that the net benefits available by beginning deployment as the Companies have proposed in this proceeding will be equaled or exceeded by further delaying deployment.

Q. Please describe the Companies' proposed full deployment of AMS.

A. The Companies are proposing to replace their existing customer electric meters with AMS meters and to install AMS gas-meter-reading indices on the majority of existing gas meters by the end of January 2021, with the first AMS meters to be deployed in the second quarter of 2019. The AMS meters the Companies propose to deploy will have two-way communication capabilities typical of smart meters, which will communicate usage and other relevant data to the Companies at regular intervals, but will also be able to receive information from the Companies, such as software upgrades and requests to provide meter readings in real time. Many of the AMS electric meters will also have remote service switching capabilities. AMS equipment planned for gas service will not have remote service switching capabilities.

The proposed full deployment of AMS will be a significant undertaking consisting of:

- Exchanging 413,000 electric meters and adding AMS gas indices to 334,000 gas meters in LG&E's service territory
- Exchanging 531,000 electric meters in KU's Kentucky service territory, as well as 30,000 in KU's Virginia service territory

- Expanding the existing radio-frequency ("RF") Mesh communications infrastructure to enable AMS RF communications across the Companies' service territories
- Updating existing meter head-end to support a full system volume of endpoints
- Installing a Meter Data Management System and Meter Operations Center, and integrating them with the Companies' Meter Asset Management system

The Companies estimate the total capital cost of the deployment will be $320 million, and that deployment-related operating and maintenance ("O&M") expenses will be $29.8 million. Of those amounts, $311.9 million of capital investment is Kentucky-jurisdictional ($146.7 million KU, $103.7 million LG&E electric, and $61.5 million LG&E gas), with the remaining $8.1 million of capital investment relating to KU's Virginia service territory. Similarly, $28.5 million of O&M expense is Kentucky-jurisdictional ($15.2 million KU, $10.6 million LG&E electric, and $2.7 million LG&E gas), with the remaining $1.3 million relating to KU's Virginia service territory. The Companies project that over the estimated 20-year life of the fully deployed AMS metering system, the Companies and their customers will receive net benefits of $483 million nominal dollars ($28.5 million NPV to 2018), resulting primarily from O&M savings compared to continuing to operate and maintain the Companies' existing metering infrastructure ($425.1 million nominal), and customer-specific savings from better identification of non-technical losses ($402.3 million nominal), and customer use of the 15-minute interval data provided by ePortal to achieve savings ($158 million nominal).

Q. Please describe the Companies' experience with AMS metering and infrastructure.

A. The Companies now have more than five years of experience with AMS meters and their supporting infrastructure. In 2012, LG&E deployed approximately 1,500 AMS meters and related infrastructure in its downtown Louisville network as part of a project to gather enhanced engineering information for network planning. LG&E's downtown network has provided the Companies with additional useful experience and information concerning AMS deployments. The Companies do not propose to replace any of these meters as part of the proposed full deployment of AMS; indeed, 1,583 meters in the downtown network remain in service and are expected to remain so for years to come.

Finally, in early 2014 the Companies filed a smart-metering proposal as part of their 2014 DSM-EE [Demand-Side-Management and Energy-Efficiency] Program Plan application: the AMS Customer Service Offering.[14] The Companies proposed to deploy as many as 5,000 AMS meters for each of KU and LG&E (electric only), along with the necessary RF Mesh network and other communications and back-end equipment. Importantly, the offering was entirely voluntary and available to residential and small commercial customers (Rates RS, RTOD, and GS). The offering also provides a MyMeter web portal allowing participants to view 15-minute, hourly, or daily energy-usage information (typically available 24-48 hours after usage occurs), which enables customers to understand their energy use and take actions to

[14] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Application (Jan. 17, 2014).

manage it. As with LG&E's downtown network, the RF Mesh AMS meters installed through the AMS Customer Service Offering will not need to be replaced as part of the Companies' proposed full deployment of AMS, and will integrate seamlessly into that deployment.

Q. What is the status of the Companies' AMS Customer Offering?

A. To date, the Companies have enrolled over 7,300 customers in the AMS Customer Offering and deployed almost 6,000 AMS meters to those customers, and are working quickly to deploy the rest in response to a recent significant increase in customer demand. By way of comparison, customer enrollments began in June 2015, and by the end of 2015 over 1,200 customers had enrolled, and by the end of 2016 almost 4,200 customers had enrolled. These total enrollment numbers are consistent with the 2014 Companies' projected enrollments when they proposed the AMS Customer Offering to the Commission.[15] The Companies have found that customers participating in the AMS Customer Offering are geographically diverse, spanning various topographies, population densities, and socio-economic segments throughout the Companies' Kentucky service territories.

Notably, the enrollment numbers of the AMS Customer Service Offering probably understate the number of customers interested in enrolling. According to data from a June 2017 survey of the Companies' customers, of those customers not participating in the offering, the vast majority (79%) stated their main reason for not

[15] *See In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Testimony of Michael E. Hornung Exh. MEH-1 at 49 (Jan. 17, 2014) (projecting 1,000 total enrollments by the end of 2015; 4,000 total enrollments by the end of 2016; and 7,000 total enrollments by the end of 2017).

participating was lack of awareness of the offering's existence.[16] If that is representative of the Companies' overall customer population, interest in AMS is likely understated by the AMS Customer Service Offering's enrollment numbers.

In addition, data from the AMS Customer Service Offering continue to suggest there is a real potential for energy savings resulting from full AMS deployment. According to a June 2016 Bellomy Research study of AMS Customer Service Offering participants who had accessed the MyMeter Dashboard, 80% of responding participants indicated they had taken some energy-saving step or measure as a result of the AMS offering.[17] Nearly 60% said they had upgraded to LED bulbs, and almost half said they had programmed their programmable thermostats.[18] Participants said they took these and other energy-saving measures because of the AMS Customer Service Offering. Similarly, the Companies' June 2017 customer survey data show that, of the survey respondents who were participating in the offering, 74% indicated they had undertaken at least some steps to increase energy efficiency or avoid wasting energy since beginning to participate in the offering.[19] Therefore, based on the consistent results of the AMS Customer Service Offering, it is reasonable to expect a full AMS deployment will result in energy savings as some customers undertake new or enhanced steps to curb their energy usage.

Q. Please describe the cost-benefit analysis the Companies performed and the conclusions of the analysis concerning the proposed full deployment of AMS.

[16] A summary of the survey data is attached to the AMS Business Case (Exhibit JPM-1) as Appendix A-9.
[17] *See* AMS Business Case, Exhibit JPM-1 at Appendix A-1.
[18] *Id.*
[19] AMS Business Case (Exhibit JPM-1) Appendix A-9.

A. The Companies' cost projections carefully consider the deployment and ongoing expenses necessary to implement and operate the various components of AMS technology across their service territories. Development of these detailed estimates resulted from robust and extensive analysis efforts, which included consideration of:

- Inclusion and refinement of costs the Companies are likely to incur, based in part on the Companies' experience with the current AMS Customer Offering
- Assumptions, contractual indications, and cost outlays articulated by peer utilities, including the Companies' affiliate, PPL Electric Utilities ("PPL EU")
- Estimates provided by internal subject matter experts across numerous business units
- Budgetary estimates from potential vendors
- Contractual pricing resulting from continued negotiations with potential vendors
- Contractually captured cost efficiencies resulting from the planned concurrent deployment of electric meters and gas indices

During the initial period of deployment, i.e., through 2022 (which includes AMS deployment in KU's Virginia service territory), the Companies forecast a capital expenditure for the AMS deployment of $320 million. During this time, AMS capabilities will progressively become operational and require maintenance, resulting in aggregate incremental O&M expenses of $29.8 million. As shown in the following table, the total lifecycle costs of the AMS deployment, i.e., costs incurred through

2040, total $502.4 million (nominal), comprising $363.8 million capital and $138.6 million O&M:

AMS Cost-Benefit Summary (2018-2040)

$M	Nominal Values	Net Present Values
(Costs)		
Total Project Costs (Capital)	(320.0)	(357.1)
Total Project Costs (O&M)	(29.8)	(26.0)
Total Project Costs	**$ (349.8)**	**$ (383.1)**
Total Recurring Costs (Capital)	(43.8)	(22.3)
Total Recurring Costs (O&M)	(108.8)	(47.9)
Total Recurring Costs	**$ (152.6)**	**$ (70.2)**
Total Lifecycle Costs	**$ (502.4)**	**$ (453.3)**
Benefits		
Operational Savings	425.1	208.3
ePortal Benefit	158.0	76.7
Recovery of Non-Technical Losses	402.3	196.8
Total Lifecycle Benefits	**$ 985.4**	**$ 481.8**
Net Benefits vs (Costs)	**$ 483.0**	**$ 28.5**

Discount Rate: 6.32%

Though the Companies are not making rate proposals in this proceeding regarding recovery of the AMS deployment's costs (with the exception of the AMS Opt-Out Special Charges), the Companies anticipate that the approximately $350 million nominal cost of the five-year AMS deployment phase (2018-2022) will have a relatively modest bill impact. For an average residential electric customer, the Companies project the peak bill impact will be approximately $2.60 per month.

More importantly, though the benefits of fully deploying AMS outweigh its costs. The NPV benefit of deploying AMS compared to continuing to use the

Companies' existing metering infrastructure is $28.5 million through 2040, with net nominal benefits of $483 million over the same period. These benefits derive predominately from O&M savings resulting from decreased meter reading and related meter services, totaling savings of almost $425.1 million (nominal). With AMS, the vast majority of meter reading will be done remotely, as will other meter services, including remote service switching, producing roughly $208.3 million of NPV savings through 2040.

Another large driver of savings from AMS is $402.3 million (nominal) of recovery of non-technical losses. Non-technical losses are energy a utility produces but is not metered or billed and is not lost due to losses one would expect in any electrical system, e.g., line losses resulting from electrical resistance in transmission and distribution lines. Most non-technical losses result from theft of service, which is much easier to detect using smart meters, but they can also result from meter-configuration errors or meter malfunctioning, both of which are also easier to detect with smart meters. The revenues resulting from reducing non-technical losses, instead recovering them from those receiving the service, will displace revenues the Companies would otherwise have to collect from other customers.

The other large driver of savings results from customers using less energy and using it more efficiently as they learn more about their own usage from the web portal that will be available to them as part of the AMS deployment. The Companies and other utilities have observed that customers who actively access such information tend to decrease their usage, as I discussed above concerning data from the AMS Customer Service Offering. Aggregating those savings through 2040 produces net savings of $158 million (nominal) and almost $67 million NPV, which are savings customers will receive directly by reducing their bills through reduced usage.

The Companies' detailed cost-benefit analysis is provided in Exhibit JPM-1 at Section 7.

Q. Please describe how the Companies calculated the benefit resulting from reducing non-technical losses.

A. First, the Companies assumed their non-technical losses amount to 2% of their projected annual electric revenues based on a report by the Electric Power Research Institute ("EPRI") titled, "*Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future*."[20] The EPRI Report states, "Considering the referenced studies and reports, statistics and analysis, and the opinions of industry experts in revenue protection, a reasonable percentage for non-technical losses is 2.0%."[21] Next, the Companies reduced that amount by 0.8% to account for projected AMS opt-outs. The Companies then assumed with full deployment of AMS (less opt-outs) that 60% of actual non-technical losses would be identified and billed, and that 60% of identified and billed non-technical losses would be collected. The Companies' recent ratio of collected theft amounts to billed theft amounts is about 60%, so it is a well-supported multiplier:

[20] The EPRI Report is attached to the AMS Business Case (Exhibit JPM-1) as Appendix A-8. Please note that the revenues included in this calculation exclude revenues from customers not eligible for AMS meters, i.e., those the Companies currently serve with MV-90 meters.
[21] EPRI Report at 1-17.

LG&E/KU Combined	2014	2015	2016	2017 YTD[22]	Total 2014-2017
Tampering Fees Billed	$380,620	$418,578	$386,947	$288,721	$1,474,866
Tampering Fees Collected	$234,630	$246,639	$215,411	$163,552	$860,232
Recovery Percentage	62%	59%	56%	57%	58%

Therefore, the total amount of non-technical losses the Companies have assumed they will detect, bill, and collect is not 2.0%, but rather 0.71%, which is a reasonable and well supported assumption (2% * 99.2% * 60% * 60% = 0.71%). Using these calculations, the Companies estimate AMS will decrease non-technical losses by $402.3 million (nominal) from 2018 through 2040. For the Companies' customers who currently bear the cost of non-technical losses, which are effectively socialized through rates, this is a significant benefit of AMS.

Q. Please describe how the Companies calculated the benefit resulting from ePortal (MyMeter) savings.

A. First, the Companies again assumed an AMS opt-out rate of 0.8%. The Companies then assumed that of their residential customers equipped with AMS, 17% would become active users, i.e., those most likely to use ePortal and therefore to change their energy consumption as a result. The 17% assumption derives from the Companies' 2016 MyMeter data, which show that 48% of AMS Customer Service Offering participants use MyMeter at least once, and that 36% of those customers become active users, i.e., a total of about 17% of the total number of AMS Customer Service Offering participants become active users. Then, based on a Smart Grid

[22] 2017 Tampering Fee Data is through November 2017.

Consumer Collaborative report showing that a 5 to 15 percent reduction in electric usage is consistently found for active users of ePortal-like systems, the Companies conservatively assumed active residential ePortal users would achieve average monthly bill savings of 3%, which is 40% lower than the low end of the reduction range (5%) from the Smart Grid Consumer Collaborative report.[23] Using these assumptions, the Companies project an ePortal benefit from 2018 through 2040 of $158 million (nominal), i.e., about 0.5% of projected residential electric revenues (99.2% * 17% * 3% = 0.5%). Note that the Companies may have understated this benefit because only residential electric customers are assumed to achieve ePortal savings in these calculations.

Q. Have the Companies conducted any studies to attempt to confirm the magnitude of their proposed ePortal benefit?

A. Yes. The Companies commissioned third-party evaluator Tetra Tech to review data from the AMS Customer Service Offering to determine if any participant savings could be observed.[24] According to Tetra Tech, current active users of MyMeter are achieving energy savings on the order of 3.8%, resulting in bill savings of roughly 3.3% based on the Companies' calculations. Furthermore, engagement with MyMeter has increased, with 70% of customers logging in at least once, of which 37% have logged in 6 or more times. Based on Tetra Tech's findings it would be reasonable to assume about 0.9 percent bill savings (3.3% x 70% x 37%) are achievable across the

[23] The Smart Grid Consumer Collaborative report is attached to the AMS Business Case (Exhibit JPM-1) as Appendix A-7.

[24] The Tetra Tech report is attached to the AMS Business Case (Exhibit JPM-1) as Appendix A-10. Tetra Tech is a global provider of consulting and engineering services with 400 offices and more than 16,000 associates worldwide, including three offices in Kentucky. The Companies have used their consulting services on a number of occasions, and provided a Tetra Tech report in support of the Companies' 2016 AMS deployment proposal.

residential electric customer base, supporting the Companies' 0.5% bill savings assumption reflected in the projected ePortal benefit.

Q. Why do the Companies use total residential electric revenues rather than just fuel-related revenues in calculating their projected ePortal benefit?

A. There are four reasons the Companies took this approach and believe it is reasonable. First, as I described above, the Companies' data from the AMS Customer Service Offering show it is reasonable; AMS Customer Service Offering participants are, on average, achieving bill savings—not just fuel-related savings—of about 0.9%.

Second, as I noted above, the Companies have effectively assumed that only residential customers with AMS will achieve savings due to ePortal information becoming available to them. But it is reasonable to assume that commercial and industrial customers equipped with AMS might also achieve some savings resulting from having access to ePortal information, though the Companies have not assumed any such savings in their ePortal benefit.

Third, customers, and particularly residential and small commercial customers, avoid more than fuel cost with each kWh of electricity they do not consume; they also avoid paying a certain amount of fixed-cost recovery due to how the Companies' rates are formulated. Certainly it is true that the Companies seek to adjust their base rates periodically to attempt to achieve full fixed-cost recovery, but that does not mean that customers cannot achieve real savings by avoiding fixed costs between rate cases by reducing their usage. (Also, the individual customers that durably reduce their usage due to ePortal information will continue to enjoy bill savings across rate cases relative to not having reduced their usage.) Moreover, as rates reset in subsequent rate cases, and assuming fixed-cost recovery must increase on a per-kWh basis due to decreased energy consumption, such rates would give customers an even greater incentive to find ways to decrease usage, which ePortal information could assist them to do.

Fourth and finally, the Companies have assumed a fixed level of ePortal savings—0.5% total bill savings—across all years of the study period. Those savings do not compound, i.e., the Companies did not assume 0.5% bill savings in year 1, reduced again by 0.5% in year 2, and so on. But in reality, as customers use ePortal information over time to reduce their usage, and assuming their energy-savings measures and behaviors are durable, their fuel savings would grow over time relative to not having ePortal-related savings. The compounding effect of such savings alone could exceed the Companies' 0.5% total bill savings assumption. Therefore, it is appropriate to use total residential revenues, not just fuel-related revenues, in calculating the ePortal benefit.

Q. The Companies appear to have assumed an average service life of 20 years for AMS meters (2021-2040) in addition to the deployment period of 2018-2020. Is this reasonable?

A. Yes, it is reasonable. Importantly, it is consistent with a number of other utilities' assumptions supporting their advanced metering deployments. For example, Ameren Illinois used a 20-year useful life to support its application to deploy advanced meters: "With respect to meter depreciation, Ameren Illinois has reviewed some of the largest AMI [advanced metering infrastructure] deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E

to base its AMI deployment on a useful life of 20 years for the AMI meter. … Moreover, Southern California Edison conducted product testing that concluded that the meter useful life would be 20 years or more."[25] Though Ameren's study period was only 20 years, which included an 8-year AMI deployment period and therefore did not include all of the benefits of the full 20-year life of Ameren's AMI meters, Ameren ensured the full 20-year-life benefits were ultimately reflected in its cost-benefit analysis by including a "terminal value" component to capture the net benefits of its AMI meters beyond the study period: "The time horizon used for the business case was 20 years. However, a terminal value was also calculated to take into account the costs and benefits associated with the un-depreciated AMI infrastructure remaining beyond the 20 year period."[26] The terminal value Ameren Illinois calculated was significant: Of the $550 million of total net present value benefit asserted for the AMI deployment, fully $154 million of it was the terminal value, i.e., the net benefits the originally deployed AMI produced beyond the end of the 20-year study period.[27] So in the Ameren Illinois case, it is clear the utility proposed both to use a 20-year useful life for its AMI meters and to include the full 20 years of net benefits associated with those meters, even though some of those benefits occurred outside the 20-year study period.

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[25] *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and* Necessity, Case No. 2016-00371, Attachment to AG's Response to LG&E DR 1, "Ameren Illinois Benefit-Cost Analysis.pdf" at pdf page 11 (Ameren Exhibit 2.4RO Page 7 of 52), available at https://psc.ky.gov/pscecf/2016-00371/rateintervention%40ky.gov/03312017030028/Ameren_Illinois_Benefit-Cost_analysis.pdf.
[26] *Id.*
[27] *Id.* at pdf pages 44-45 (Ameren Exhibit 2.4RO Pages 40-41 of 52).

Similarly, the AMI Business Plan Consolidated Edison submitted to support its AMI proposal used a 20-year cost-benefit evaluation period.[28] Although the 20-year evaluation period included six years of AMI project life (including five years of AMI system deployment),[29] the ConEd study does not appear to include capital costs to replace significant numbers of early-deployed meters; in other words, ConEd appears to have assumed at least 19 years of service life for deployed AMI meters, and likely 20.[30]

In addition to the two studies cited above, an independent Duke Energy Ohio Smart Grid Audit and Assessment conducted for the Staff of the Public Utilities Commission of Ohio used a 20-year benefit period and assumed a 20-year useful life for AMI meters.[31] Duke Energy Indiana similarly used a 20-year study period in support of its smart-grid proposal.[32] The Maine Public Utilities Commission approved an AMI project for Central Maine Power Company based on a 20-year cost-benefit study period.[33] Also, BC Hydro in British Columbia, though not an IOU, used a cost-benefit analysis that assumed at least a 20-year service life for deployed

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[28] Case No. 2016-00371, Attachment to AG's Response to LG&E DR 1, ConEd Study at pdf page 44 (ConEd Study page 40), available at https://psc.ky.gov/pscecf/2016-00371/rateintervention%40ky.gov/03312017030028/ConEd_AMI_Plan.pdf.
[29] *Id.*
[30] *See* ConEd Study at pdf page 61 (ConEd Study page 57), Figure 5-3.
[31] Duke Energy Ohio Smart Grid Audit and Assessment dated June 30, 2011, at 70 ("MetaVu forecast annual benefits from 2009 to 2028 (20 years) to estimate the NPV of each.") and 83 ("It must be noted that smart meters will also need to be replaced after life cycle completion, estimated to be 20 years"), available at https://www.smartgrid.gov/files/Duke_Energy_Ohio_Smart_Grid_Audit_Assessment_201104.pdf. .
[32] *See* IURC Cause No. 43501, Order on Settlement at 6 (Nov. 4, 2009) ("Mr. Christopher D. Kiergan, Executive Consultant with KEMA, Inc., described and sponsored the SmartGrid cost/benefit model ("SmartGrid Model" or "'Model"), which generally captures the capital expenditures, O&M expenses, and associated benefits for 2009-2028, as well as calculating an overall 20-year net present value for the SmartGrid Initiative."), available at http://www.in.gov/iurc/files/43501order_110409.pdf.
[33] *See* Maine Public Utilities Commission, Docket No. 2007-215(II), Order at 6 (Feb. 25, 2010) ("CMP has provided a cost-benefit analysis that shows with the DOE grant, its proposed AMI investment will result in approximately $25 million in operational savings over 20 years"), available at https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2007-00215.

AMI meters: its cost-benefit study period ran through its fiscal year 2033, but AMI meters were to begin deployment in 2011 and be complete by 2012, and the study did not include a wholesale replacement of meters prior to the end of the study period.[34]

In addition, the Companies have included in the total cost of the AMS project the cost of replacing a number of electric meters and gas indices over the 2018-2040 period. More specifically, based on vendor conversations, the Companies have assumed the need to purchase spare AMS meters and gas indices annually equal to 0.5% of AMS meters deployed.

Therefore, it is reasonable for the Companies to assume an AMS useful life and benefits from 2018-2040.

Q. Did the Companies account for the cost of retiring their existing meters in their cost-benefit analysis?

A. Yes, though with a change from the Companies' 2016 AMS proposal. The Companies continue to propose to remove and retire existing meters incapable of communicating with the proposed AMS RF Mesh network. But unlike the Companies' 2016 proposal, they do not propose to recover the cost of such meters over a shorter period than the meters' remaining service lives. For that reason, there is not a line-item in the AMS Business Case cost-benefit summary table shown in my testimony, which is a change from the 2016 proposal, in which the Companies proposed to accelerate recovery of the cost of existing non-AMS meters to be retired. Of course, the Companies are not proposing or requesting any particular rate

[34] *See, e.g.*, BC Hydro Smart Metering & Infrastructure Program Business Case at 1 and 33, available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf.

treatment of the early-retired meters in this proceeding; rather, the Companies seek only to explain the reasoning supporting their cost-benefit analysis in this regard.

Q. In addition to the quantified net benefits you have already described, how will customers benefit from a full deployment of AMS?

A. Customers will benefit in numerous ways. First, as current AMS participants already can, all customers with Internet access will be able to use a web portal to access information about their usage at any time of day or night, download consumption patterns to better understand how they use energy, and explore different products and programs that may align to their needs. Second, full AMS deployment will enable the Companies to develop time-of-day or more dynamic rate structures that could help customers reduce their bills. Third, the ability to access near real-time energy data will improve customer service representatives' ability to address customers' questions and concerns regarding individual customer outages, power quality, and energy usage. Fourth, full AMS deployment will enable the Companies to better localize and resolve power outages, which will help reduce customer outage times. These benefits, though difficult to quantify, are real, and will improve customers' service and their customer experience.

Q. How will customers who lack Internet access benefit from AMS?

A. There are a number of benefits customers who lack Internet access will receive from AMS, such as automated outage notification to the Companies for system restoration and individual service restoration, off-cycle reads for customer service inquires, and increased customer safety.[35] In addition, cost savings resulting from these benefits will be reflected in future rate proceedings, which could further benefit such customers.

Q. Will the remote service switching capability of the full AMS deployment also be a benefit?

A. Yes. The remote service switching capability of the full AMS deployment can benefit customers who move to or from a premise by having their service established or terminated very quickly through contact with a customer-service representative or through self-service using the Companies' My Account web portal. Additionally, AMS's remote service switching ability will allow the Companies to reconnect a customer's service nearly instantaneously upon payment for service previously disconnected for non-payment. The ability to provide these services remotely and quickly meets customers' current expectations of almost immediate personalized service of the kind they often receive from other service providers such as cable TV and telephone providers.

Additionally, the ability to remotely switch service can help avoid injuries. Since 2011, Field Services Personnel have encountered about 80 physical threats related to disconnections per year on average. Throughout 2017, the Companies received 96 threats related to disconnections. Indeed, threats in this area account for

[35] There is reason to believe Internet access is reasonably common in the Companies' service territories and has grown over time. According to the U.S. Census Bureau's 2015 American Community Survey, 70.9% of Kentucky households had a broadband Internet subscription, which does not count sub-broadband Internet access methods, including dial-up. *See* Computer and Internet Use in the United States: 2015, page 8, table 2 (available at: https://www.census.gov/content/dam/Census/library/publications/2017/acs/acs-37.pdf, accessed Dec. 12, 2017). This is a significant increase from Census data from 2003, which showed Internet access in Kentucky for only 50% of households. *See* Computer and Internet Use in the United States: 2003, page 5, figure 3 (available at: https://www.census.gov/content/dam/Census/library/publications/2005/demo/p23-208.pdf, accessed Dec. 12, 2017).

nearly half of the total threats received across the Companies' operations and are following a concerning and increasing trend, reaching an all-time high of 206 in 2017. During these safety incidents a number of employees are called into action to ensure safety of the employee, investigate the circumstances, and report the incident to the Commission. The Electrical Technical Training and Public Safety department estimates that between 37 and 58 employees are called in response to a safety incident of this kind. Reduced personnel exposure to hazards due to AMS implementation reduces the need for this coordinated response, freeing up employee time that can be spent on other tasks. This can potentially create a relative reduction in personnel costs over time, which will benefit customers. Therefore, though the Companies have not attempted to quantify these benefits, they are real benefits of AMS generally and its remote service switching capability specifically.

The Companies recognize that remote service switching can create concerns, particularly for low-income customers and other vulnerable customer groups. As Mr. Huff describes in his testimony, the Companies and the other AMS Collaborative participants took those concerns seriously and discussed them during their October 17, 2017 meeting. As Mr. Lovekamp explains in his testimony, the Companies are not proposing to change any of their service disconnection or reconnection policies or tariff provisions in this proceeding, and will continue to comply with all applicable Commission regulations concerning such matters, including winter hardship reconnection requirements. I too can assure the Commission that the Companies do not intend or desire to use remote service switching to circumvent any existing regulations or customer protections provided in the Companies' tariffs regarding service disconnections; rather, the Companies are firmly committed to following those regulations and tariff provisions.

Q. Will the Companies allow customers to opt out of the full AMS deployment?

A. Yes, subject to the Companies' operational and safety requirements. This is a significant change from the Companies' 2016 proposal for full AMS deployment. As Mr. Huff explains in his testimony, this change is a direct result of input the Companies received during their 2016 base-rate cases from AMS Collaborative participants and others. Although ubiquitous AMS deployment is best from a technical perspective, providing excellent customer service is a primary goal of the Companies, and permitting customers who desire to opt out to have the ability to do so—while bearing the full cost of their decision—aligns with the Companies' customer-service focus. Mr. Huff explains in his testimony the terms the Companies propose concerning opt-out, including a proposed opt-out charge structure. Mr. Lovekamp presents tariff sheets and cost support for AMS Special Charges for the Companies.

Q. What is the Companies' plan to educate and inform customers about the AMS deployment and how customers can benefit from it?

A. The Companies continue to believe that a successful education and communications plan will drive high levels of customer engagement and help customers achieve maximum benefits from AMS. The Companies have similarly deployed AMS metering in LG&E's downtown network with a robust communication plan that has avoided any customer concerns. Comparable to these successful communication plans, the Companies will develop a multi-faceted customer education and communications plan to educate customers, as well as community stakeholders, throughout the duration of the project and after customers receive their AMS meters to encourage participation and support of future programs.

The Companies' customer-education plan will include offering information on a variety of topics, including how the program works; the meter installation process; the new tools and features, such as the ePortal (MyMeter) functionality currently available to AMS Customer Offering participants; and new ways to help manage their energy use and modify their services. Based on discussions in the AMS Collaborative, it will be a particular focus of the plan to educate customers about ePortal and the importance of energy savings customers can achieve by acting on the granular energy data ePortal provides.

The Companies recognize that they serve a diverse population that has different needs and requires different communications and education approaches. To reach all customers and community stakeholders, the Companies plan to use a wide array of communication channels, such as:

- Print and digital advertising
- Automated calls
- Community outreach and events
- Customer newsletters and bill inserts
- Direct mail
- Email
- Informational updates through the ePortal
- On-line videos and banners

- Media relations
- Social media

Additional details and examples concerning the Companies' communication plan are in Exhibit JPM-1 at Section 9.

Q. What impacts will full deployment of AMS have on the Companies' existing DSM-EE AMS Customer Service Offering?

A. The Companies recently applied to the Commission for approval of their 2019-2025 DSM-EE Program Plan, which included requesting to continue the AMS Customer Service Offering through the end of 2025.[36] (The AMS Customer Service Offering received Commission approval through the end of 2018 as part of the Companies' 2014 DSM-EE Plan.[37]) If the Commission approves full AMS deployment as requested in this proceeding, the Companies will continue to operate the AMS Customer Service Offering as a DSM-EE program to ensure the offering's participants can continue receiving the offering's benefits while the Companies fully deploy AMS to all customers. But to avoid customer confusion, upon approval of the proposed CPCNs the Companies plan to cease promoting the AMS Customer Service Offering and focus on the educational and communication needs of the AMS full deployment. Customers who desire to have an AMS meter installed ahead of the full deployment schedule for their area will be able to contact the Companies and request

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[36] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Application (December 6, 2017).

[37] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Order (Nov. 14, 2014).

an accelerated installation, which requests the Companies will accommodate to the extent reasonable and feasible.

From a ratemaking perspective, the Companies plan to propose incorporating the capital and operating costs of the AMS Customer Offering into base rates in their next base-rate cases if the Commission approves the Companies' full AMS deployment proposal in this proceeding. At that time, the AMS Customer Offering as a DSM-EE program would end, while still allowing the customers participating in the AMS Customer Offering to do so without interruption.

IV. CONCLUSION

Q. What are your conclusion and recommendation?

A. Part of the Companies' mission statement is "to provide reliable, safe energy at a reasonable cost to our customers."[38] Full AMS deployment will support that mission because it will enhance the Companies' ability to improve reliability while providing net benefits to customers. Based on the evidence provided above and in the Company's application in this proceeding, I conclude the proposed full deployment of AMS across the Companies' Kentucky service territories will provide significant benefits to customers and therefore serves the public convenience and necessity. Therefore, I recommend the Commission approve the proposed deployment, grant the requested CPCNs, and approve the proposed AMS Opt-Out Special Charges, as well as the rest of the relief the Company is requesting in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

[38] LG&E and KU Vision and Mission statements. https://lge-ku.com/our-company/vision-mission (accessed Nov. 20, 2017)

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John P. Malloy**, being duly sworn, deposes and says that he is Vice President – Gas Distribution for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of January 2018.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

John P. Malloy
Vice President, Gas Distribution
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4836

Education

Spalding University, Doctorate of Education, Leadership – currently enrolled

Indiana University, Master Business Administration – 2000

Indiana University, B.S. in Finance – 1998

Previous Positions

LG&E – KU Services Company

2017 – Current	Vice President, Gas Distribution
2013 – 2017	Vice President of Customer Services
2007 – 2013	Vice President of Energy Delivery – Retail Business
2003 – 2007	Director of Generation Services

Louisville Gas and Electric Company, Louisville, Kentucky

1998-2003	Maintenance Manager, Mill Creek
1996-1998	Manager Resource / Project Management, Louisville Gas and Electric - Fleet
1989-1996	Instrument and Electrical Supervisor, Mill Creek
1986-1989	Instrument and Electrical Technician, Mill Creek
1984- 1986	Production Operations, Mill Creek
1983- 1984	Coal Handling Operations, Cane Run
1980- 1983	Instrument and Electrical Technician, Cane Run

Other Professional Associations

Spalding University	2016 – current	Board of Trustees
Louisville Orchestra	2016 – current	President, Board of Directors
	2012 – 2016	Executive Committee – Board of Directors
	2008 – 2012	Vice President of Development
LG&E Credit Union	2010 – current	Chairman Emeritus
	2001 - 2010	Chairman and CEO, Board of Directors
	1998 - 2001	Treasurer, Board of Directors
	1995 - 1998	Board of Directors

Leadership Kentucky	Board of Directors	
	2016 – current	Secretary, Executive Committee
	2009 – 2016	Board of Directors
Catholic Education Foundation		
	2016 – current	Board of Directors
Kentucky Association of Manufacturers		
	2016 – 2018	Chairman – Board of Directors
	2012 – 2016	Executive Committee – Board of Directors
	2010 – 2012	Chairman of Energy / Natural Resources Policy Committee

Electric and Gas

Advanced Metering Systems

Business Case

January 2018

LG&E KU
PPL companies

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Appendices

1 Executive Summary

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively "Company") have undertaken a revised and refined business case analysis of Advanced Metering Systems (AMS) deployment across their entire Kentucky and Virginia service territories.[1] Full AMS deployment will extend to the vast majority of customers the benefits currently experienced by participants in the Company's AMS Customer Service Offering, which the Company operates as part of its demand-side management and energy-efficiency ("DSM-EE portfolio").[2] This deployment will empower customer choice, streamline meter-related processes, produce operational savings that can be passed on to customers, and establish foundations for increased grid resiliency and efficiency.

AMS introduces bi-directional communications between Company systems and the metering endpoints of all AMS-equipped customers.[3] This allows for detailed electric and gas consumption information to be made available for a variety of customer and utility uses. Customers can make more informed decisions about how and when to use energy by reviewing their usage patterns with the help of enhanced customer service channels. Utility operations will allow the Company to restore outages faster, optimize grid performance, and make better-educated capital deployment planning decisions for future infrastructure investments.

To extend AMS to in-scope customers, the Company will implement the capabilities per a three-year deployment schedule, with the deployment of 1.3 million meters and system implementation occurring in parallel. To take advantage of available resources, current meter deployment plans call for a levelized deployment schedule across the Company's Kentucky and Virginia service territories with full system implementation and meter deployment to be completed by mid-year 2021. In advance of deployment, the Company will begin a robust customer education and communication plan to address deployment logistics, customer concerns, and AMS benefits. This informational exchange will endure beyond deployment to

[1] LG&E and KU conducted and filed their first AMS Business Case in the context of requesting certificates of public convenience and necessity for full AMS deployment in their 2016 Kentucky base rate cases. Please note that a glossary of terms and acronyms used in this document is in Appendix A-11.

[2] Details of customer benefits from the DSM AMS deployment is in Appendix A-1, Advanced Meter Service Participant Study - Bellomy Research.

[3] There are no current plans to replace the approximately 1,800 MV90 meters currently installed and used for customer billing. These meters have been excluded from the planned AMS deployment and are not considered AMS-enabled or AMS-equipped customers for the purpose of this business case. MV90 meters are an industry standard solution for large volume customers typically associated with commercial and industrial customers.

LG&E KU PPL companies

ensure customers remain engaged, informed, and empowered to fully maximize their available benefits.

The Company plans to invest $503 million ($364 million of capital and $139 million of O&M) to fund full AMS deployment and maintenance over the 2018-2040 timeframe. Advanced meters, network infrastructure, and supporting systems make up the majority of the costs. These costs are more than offset by the projected $985 million in expected benefits across the same time period. The main quantitative benefits revolve around meter reader reductions, meter service efficiencies, reduction of non-technical energy losses, and potential energy savings resulting from customer adoption of ePortal-enabled insights. Qualitatively, the Company expects increased customer satisfaction through increased billing transparency, increased optionality, easier scheduling of meter services, better-informed customer service interactions, and decreased outage durations. Based on a rigorous cost-benefit analysis, the Company projects that over the 2018-2040 timeframe the benefits of a full AMS deployment will exceed its costs by a total of $28.5 million (net present value (NPV) to 2018), making it a prudent investment on behalf of the Company's customers.[4]

2 Introduction

LG&E and KU are regulated utilities serving customers in Kentucky and Virginia as part of the PPL Corporation (PPL) family of companies. The AMS Program has been developed as a means to deploy mature metering technologies for improved customer experiences. This AMS Business Case demonstrates the value to customers associated with the deployment of advanced electric meters, advanced gas indices, and the supporting infrastructure and systems for customers. These technologies represent a step forward in the way the Company interacts with customers, operates its business, and restores the electric distribution system. The AMS Program will also support future technologies that will help the Company to continue enabling significant improvements in the customer experience and grid operations. AMS and future technologies are an extension of the Company's continued commitment to embracing new technologies and are vital to supporting the Kentucky Public Service Commission's goals as established in Administrative Case Number 2012-00428 including:

- Providing customers with increased access to their consumption, rate, and billing information while maintaining strict customer privacy and cyber-security standards.[5]
- Continuing investment in advanced technologies at the right time. [6]

[4] See Appendices A-6.1 – A-6.7 for Capital Evaluation Models.
[5] Kentucky Public Service Commission, Case #2012-00428, Final Order 2016-04-13, p.33-34.
[6] Kentucky Public Service Commission, Case #2012-00428, Final Order 2016-04-13, p.33-35.

PPL companies

- Increasing customer education focused on available programs, expected benefits, privacy, and health concerns associated with advanced technologies.[7]

The AMS Business Case evaluates the costs of implementing the necessary technologies and processes, along with the benefits associated with enhanced grid operations and customer service capabilities enabled by AMS. AMS technologies will move the Company's electric and gas distribution grid towards greater levels of efficiency and reliability, and will empower customers through more information and control over their energy usage and costs, enhancement of existing customer programs, and increasingly positive customer experience. Further, AMS enables the use of metering data to support the Company's energy future through coordination with technologies such as Volt/VAR optimization (VVO), Advanced Distribution Management Systems (ADMS), Advanced Distribution Automation (ADA), demand modeling, load forecasting, and distributed energy resources (DERs) integration.

3 Background and Current Situation

The Company serves 1.3 million customers and has consistently ranked among the best companies for customer service in the United States.[8] LG&E serves 324,000 natural gas and 407,000 electric customers in Louisville and 16 surrounding counties, while KU serves 549,000 customers in 77 Kentucky counties and five counties in Virginia.

The Company has a long history of embracing new technologies to provide customers with the best possible experience. Some examples include:

- Power Line Carrier Metering technologies - In 1999, the Company installed more than 4,000 Turtle System-enabled meters which represented the Company's first production efforts to remotely transmit meter reads to back-office systems. The Turtle System provides one-way communication of kWh meter data from the meter to the Company once a day.
- Responsive Pricing and Smart Meter Pilot - In 2007, the Company embarked on a pilot program to assess the net impact of various combinations of information, equipment, and pricing signals on customers' electric usage and the ability to shift usage from

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[7] Kentucky Public Service Commission, Case #2012-00428, Final Order 2016-04-13, p.17-19, 33-35.

[8] In the 2017 J.D. Power and Associates (JD Power) Electric Utility Residential Customer Satisfaction Survey, Kentucky Utilities Company ranked first and LG&E ranked second among their Midwest mid-size region peers. In 2016 JD Power Gas Utility Residential Customer Satisfaction Survey, LG&E ranked first among their Midwest mid-size region peers.

higher-demand to lower-demand time periods. Paired with time-of-use rates, the Company installed a Trilliant metering solution including 2,000 meters to residential and small commercial customers with varying combinations of other devices like in-home displays, thermostats, and load-control devices. This offering provided the Company with valuable insights into enabling energy management tools for our customers. The feedback from customers who participated in the pilot indicated they valued the feeling of control they had over their energy use that the information from the pilot provided.

- Downtown Network – In 2014, the Company deployed approximately 1,500 advanced meters in the downtown Louisville area to support distribution network operations and analytical needs. The system gives the Company the ability to monitor load, voltage, and engineering-specific data to improve modeling, analysis, and overall management of the downtown Louisville secondary network. It supports enhanced capacity planning; enables accurate modeling of normal, peak, and contingency conditions; and mitigates the possibility of a significant outage event in the core downtown Louisville area, and associated damage to critical network infrastructure.
- AMS Customer Service Offering – Starting in 2015, the Company began offering up to 10,000 advanced meters to customers who opted-in as part of the Company's approved DSM-EE program portfolio. This includes Landis + Gyr (L+G) radio frequency (RF) mesh network technology in Louisville and Lexington, as well as the Itron TOTALGRID cellular solution for customers without existing or installed RF mesh infrastructure.

PPL Electric Utilities (PPLEU), a utility serving customers in Pennsylvania and a member of the PPL family of companies, is currently deploying advanced meters for the 1.44 million customers in its Pennsylvania service territory. The Company will continue to leverage lessons learned and best practices from PPLEU for successful deployment in Kentucky.

Based on these experiences and findings, the Company plans to move forward with a full-scale deployment of advanced meters across the LG&E, KU, and Old Dominion Power service territories to take advantage of economies of scale to bring customers the full benefits AMS can provide.

Across industries, technology has facilitated the evolution of customer expectations. Utility customers have always expected safe and reliable energy service. Increasingly, customers are interested in understanding how their behavior drives their energy bills, how their energy use affects the environment, and which programs or products are available that make sense for their needs. Information addressing these questions is available from a variety of sources, but can be difficult for the average customer to find or understand. Full AMS deployment will allow the Company to further enhance its role of Trusted Energy Provider, by answering these questions for customers through access to detailed and personalized consumption data, corresponding tools to actively manage their energy usage, and tailored recommendations that can save customers money.

Another important item to note when surveying the current situation with regard to AMS is that the Company and a number of intervenors from the Company's 2016 base-rate cases recently concluded the pre-deployment portion of the AMS Collaborative process arising from the settlement reached in those cases.[9] There are three ways AMS Collaborative participants and other intervenors in the Company's 2016 base-rate cases influenced the current proposal for full deployment of AMS:

- First, the Company proposed in 2016 a system-wide deployment of AMS with no option for customers to opt out of AMS. The Company now proposes to permit customers to opt out of AMS service. The decision to include an opt-out was influenced and shaped by feedback from AMS Collaborative participants.
- Second, the Company's 2016 AMS proposal accounted for spare AMS meters and gas indices as a one-time, up-front purchase in their 2016 AMS deployment proposal. Based on input from the 2016 base-rate cases, the Company has now accounted for purchases of spare meters and gas indices throughout the 2018-2040 service life of the proposed AMS project.
- Third, the Company's 2016 AMS proposal provided for a five-year recovery of the undepreciated book value of the meters to be removed and replaced by AMS meters, which effectively accelerated the recovery of the replaced meters' book value relative to their remaining service lives. Based on input the Company received during the 2016 base-rate cases, the Company now proposes not to recover replaced meters' undepreciated book value on an accelerated schedule, but rather to recover it over the meters' remaining service lives. This approach effectively removes any impact of the replaced meters' undepreciated book value from the AMS cost-benefit analysis presented herein.

4 Corporate Vision and Mission

[9] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017).

The Company's corporate vision is to empower economic vitality and quality of life, and its mission is to provide reliable, safe energy at a reasonable cost to our customers and best-in-sector returns to our shareowners. Six core values of Safety and Health, Customer Focus, Employee Commitment and Diversity, Integrity and Openness, Performance Excellence, and Corporate Citizenship provide the guiding principles by which the Company does business.

A strategic investment in AMS reflects these six core values:

- *Safety and Health* - AMS technology improves outage response and restoration, resulting in increased safety to the customer and Company personnel during outage events. It also lowers employee drive time leading to decreased auto-related safety incidents. Additionally, remote service switching limits employees' exposure to dog bites, dangerous facilities, and customer threats. The Company has averaged approximately 80 such incidents per year since 2011 and the number of such incidents in 2017 far exceeded that average with 96 threats.

- *Customer Focus* - Increased volume and availability of customer data will better inform customers and customer service representatives. This will help customers better understand their bills and customer programs that would benefit them. In addition, this will help the Company's Customer Service Representatives provide better customer service through near-immediate access to a customer's service data, reducing the necessity of field visits to address customer concerns.

- *Diversity and Engagement* – In the area of engagement, improved usage data will increase communication between customers and the Company, leading to better customer outcomes. For example, customers can engage in proactive management of their energy usage. With the help of trained Customer Service Representatives, customers can explore the impact of behavior changes, specific programs, or optional rate structures.

- *Performance Excellence* - AMS technology has long-term benefits including operational efficiencies and increased reliability while setting the foundation for future technologies that continue to support the goal of providing the best service to customers.

- *Integrity and Openness* - The Company is committed to honest communication with its customers. Providing customers with improved consumption data supports this and promotes positive interactions with the Company. The Company also will be implementing a robust customer education and communication plan that addresses customers concerns about safety, privacy, and cyber security.

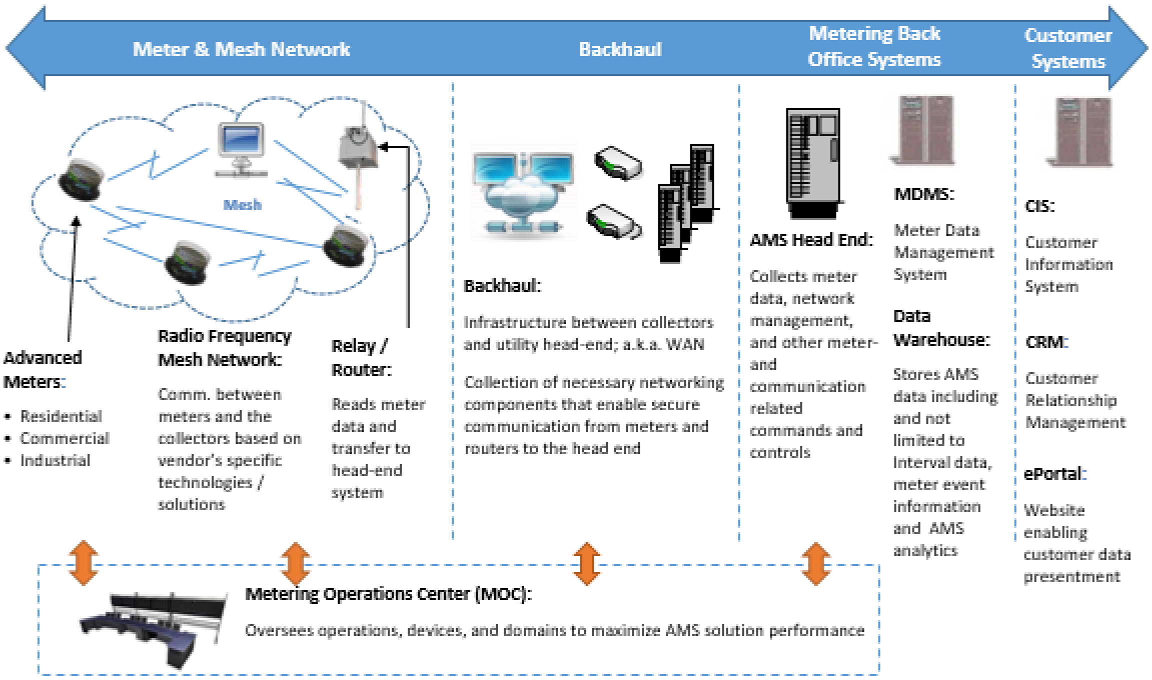
- *Corporate Citizenship* -The AMS program will increase data availability, improving the Company's relationships not only with customers but also with regulators by establishing a foundation for future products and services. Also, the AMS deployment and subsequent operations will comply with all applicable legal requirements, including orders of the Kentucky Public Service Commission.

The AMS upgrade directly supports these Company values by facilitating positive customer interactions, providing customers with information and tools to make smarter energy choices, and equipping the Company with the technology to improve efficiency, reliability, and customer service.

5 Strategy

5.1 Introduction to AMS

AMS is a collection of mature technologies that use advanced meters and supporting infrastructure to enable remote two-way communication between meters, utility customers, and grid operation systems. AMS allows for more detailed measurement of customer energy consumption, more frequent collection for customer presentment, and enhanced diagnostic capabilities to monitor and alert central operations when power quality violations (e.g. outages, voltage sags) are determined for individual customers. The core components and a high-level overview of the flow of information are in the following diagram:



5.2 Data Communications with Customers

An improved customer experience is a central driver for this program, making customer-facing capabilities highly important. These include:

- Web Portal Presentment (ePortal): Today's energy consumers have come to expect more information on their terms and within their time constraints. The most flexible way to satisfy this expectation is to integrate data captured in the Company's back-office systems with a web portal. In so doing, customers are able to access information about their usage at any time, day or night, download consumption patterns to better understand how they use energy, and explore different products and programs that may be better aligned to their specific needs. The Company expects availability of data to drive increased interest in optional rates and energy efficiency programs that have already demonstrated positive benefits for those customers that have taken advantage of these programs.
- Enhanced Representative Enablement: Customer Service Representatives (CSRs) are currently limited in their real-time access to individual customer outage, power-quality, and detailed metering information. Using AMS technologies, CSRs will be empowered to improve the customer experience in real-time while a customer is on the phone or in the business office and not be entirely dependent on scheduling a field visit to address a customer's issue. Power outages can be assessed remotely to determine if an entire circuit is experiencing an outage or if a problem is behind the

meter. CSRs will have access to information about a customer's individualized experience to assess how many outages have occurred versus how many have been reported. Meters that have been disconnected (for various reasons) can be remotely re-connected in real-time.

- Proactive Notification: Customers may choose to participate in numerous programs where information is shared via outbound call, email, or Short Message Service (SMS) text message. Information about power disruptions, voltage spikes, demand response events, power restorations, and monthly to-date notifications represent a starting point of functionalities contemplated through this program.

5.3 Electric Meters and Gas Indices

Each of the Company's electric customers will receive an AMS electric meter. Each LG&E gas customers will receive a gas index equipped with an AMS module, which will be connected to the gas meter. Any customers who have both electric and natural gas service with the Company will have AMS technology installed for each service. AMS technology is solid-state, can measure consumption in intervals as frequently as 15 minutes, offers bi-directional wireless communication, and can support remote firmware upgrades. Transmission of consumption data for both electric and natural gas uses the same communications network. Consequently, there is little additional cost to capture and transmit a customer's natural gas consumption data. For reference, the average cost of an AMS electric meter is $97 compared to $62 for a gas index, with many of the network and system costs not rising materially with the inclusion of gas indices. One additional benefit of installing only a gas index module is that no interruption of gas service is required to install the index module. As a result, few, if any, customers will experience a service outage during the index replacement.

The technology for natural gas AMS has several differences from electric AMS that impact its capabilities. Various approaches and configurations were analyzed to maximize the cost effectiveness for customers. Some of these considerations include:

- Battery Power: Gas indices are battery powered. They cannot power themselves from the commodity they measure (as electric meters do). As a consequence, unplanned gas AMS communications are limited to minimize battery drain. More frequent communications will result in a shorter operational lifespan requiring more frequent and costly index or battery replacements. Current technology designs these devices for very low power consumption, which allows the battery to last an average of 20 years under the standard operating profile suggested by the manufacturer.

- Remote Service Switching: Gas indices perform a monitor-only function relative to the gas meter and cannot connect or disconnect service. The technology exists where gas meters can be simultaneously replaced to enable this function, but safety concerns associated with remote service switching of a customer's natural gas service outweighed the potential benefits of this functionality.

- Gas Service Quality: Quality of service functions such as pressure monitoring, leak detection, and cathodic protection monitoring and reporting depend on replaced gas meters and other communications-enabled components. Enhancements in this area were not included because the enablement of gas communication does not require the replacement of natural gas meters.

Despite these constraints, deploying advanced electric meters and natural gas index upgrades together allow the Company to holistically maximize realizable benefits through economies of scale. Many back-office components (such as head end, meter data management, and systems integration) have significant fixed cost structures that vary little to accommodate gas AMS. Conversely, certain cost savings (such as meter reader reductions) cannot be fully realized if gas AMS is avoided, or worse, newly established inefficiencies of gas-only manual meter readings could result in cost increases to gas customers who would need to bear the full burden of meter-reading efforts.

Ultimately, AMS for electric and natural gas service minimizes operational complexity throughout the organization and optimizes maintenance of a unified billing management process. Meter technicians are able to focus on more impactful activities such as ensuring safety and metering accuracy are maintained in accordance with existing standards. Further, all customers, regardless of the commodity they purchase, will benefit from increased billing transparency and granularity allowing them to make more informed decisions about their energy usage.

5.4 Ownership and Maintenance of AMS Components

The Company will own and maintain all electric and gas meters, the corresponding AMS communications network, and all back-office systems' processing and storage of customer usage data. The Company will manage all testing, inventory, and records associated with these assets.

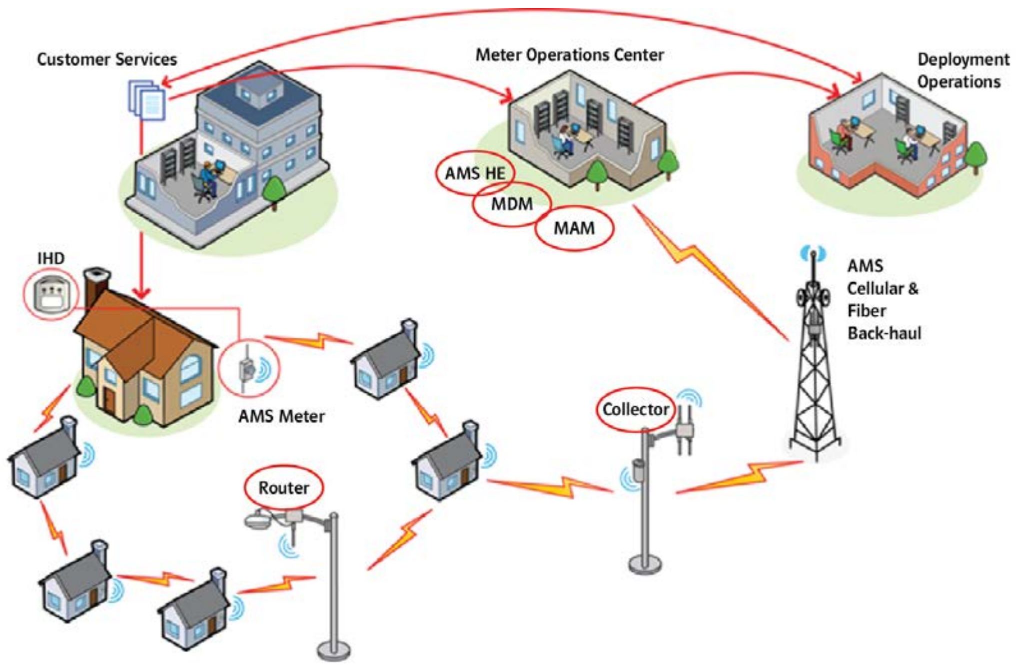
The Company expects a small percentage of instances in which a technician arrives on site and finds damage to the customer-owned meter base preventing installation of an AMS meter. In these situations, the Company will offer to repair or replace the meter base at a customer's home or business as needed. This will be done at no additional cost to the customer, provided the customer signs a waiver confirming their understanding that these repairs are on a one-time basis and that the customer is responsible for meter base repairs and maintenance going forward. The customer also has the option to refuse this service, and repair the meter base using a contractor of their choice at their own cost.

The Company recognizes that by owning these assets, the Company takes on a significant responsibility to safeguard and protect customer data. The Company will implement various cyber-security measures at all network connection points of the AMS communication network.

The Company also works regularly with industry experts to improve cyber-security practices and will discuss cyber-security plans in greater detail later in the document.

5.5 System Components

The following descriptions of end-to-end metering technologies are meant to provide a broad explanation of the capabilities of individual components and technologies necessary to implement and operate an effective and efficient AMS platform. The following is a high-level overview of an AMS System:



5.5.1 End Point Devices:

5.5.1.1 Advanced Meters

An advanced meter is a piece of electronic equipment used to measure electricity or natural gas consumption at residential, commercial, and industrial locations. The meter digitally communicates interval data and register reads using two-way telecommunications infrastructure. Generally, the meter stores the data and communicates all stored data at scheduled intervals, e.g., once per 24-hour period or once every 8 hours. Advanced meters can be equipped to use either a cellular radio or a mesh network, to interface with a utility's backhaul, or the portion of the network comprising intermediate links between the core network and smaller subnetworks,[10] and back-office systems.

It is expected that the majority of the Company's electric meters will be completely replaced.[11] The new electric meter will contain the meter, data storage, index, and communications component. With LG&E gas meters, only an index module (a communication component that is capable of securely and efficiently sending information packets a short distance) is expected to be installed. If an automated meter reading (AMR) device already exists on a gas meter, it will be replaced with an AMS-enabled index. In addition, in approximately 1,500 instances, LG&E will either replace the index or the entire gas meter because they have an odometer-style index that is not compatible with the AMS gas index module.

An advanced meter has a number of capabilities depending on the type of meter and whether it measures electricity or gas:

Capabilities of both gas and electric advanced meters:

- Tamper and theft detection;
- More precise measurement;[12]
- Real-time data query: Today, a technician must visit a meter to get a current reading. With AMS technology, readings can be initiated by system scheduling, CSRs, or control center operators; the meter can be pinged to report current readings (depending on commodity; these details can include power and gas consumption, outage status, voltage status, and other characteristics);
- Interval granularity: Today, energy consumption data is typically captured monthly. AMS meters are typically configured to capture energy consumption at 15-minute intervals. More frequent interval checks may be considered as technology and customer expectations evolve;
- Reading frequency: Today, energy consumption data is typically provided back to the Company once a month during the manual meter reading process. With AMS technology, energy consumption data can be transmitted back to the AMS head-end three to four times a day and then uploaded to an online portal for customer viewing daily; and

[10] See https://en.wikipedia.org/wiki/Backhaul (telecommunications).
[11] The replacement of MV90 billed meters currently installed have been excluded from the planned AMS deployment.
[12] Meters meet existing ANSI C12.20 standard accuracy classes and are either within +/- 0.2% or +/- 0.5% accurate. Legacy electromechanical meters were generally built to ANSI C12.1 standards of +/- 1%. Precision also references the increased data granularity made available to customers.

LG&E KU
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- Secure communications: AMS cybersecurity protocols allow for secure, encrypted communication between end points and AMS supporting infrastructure, which aids in the prevention of fraudulent interception of customer data.

Capabilities of electric meters only:

- Voltage monitoring: AMS meters have the ability to provide voltage monitoring and real-time notifications for voltage excursions;
- Power outage notifications (PON) AMS meters automatically notify Company back-office systems of a loss of power;
- Power restoration notifications (PRN) AMS meters proactively communicate that power has been restored;
- Remote service switching (RSS): Service to the majority of AMS meters can be controlled without the need to physically visit the meter. All connection and disconnection of service will continue to be governed by regulatory and internal policies, which currently includes notification to customers in danger of being disconnected and offering customers payment plans with the company to avoid disconnection;
- Demand Response (DR): ZigBee communications to interact with Home Area Network (HAN) devices as the "last mile" of Demand Response (DR) capabilities;[13]
- Customer-enabled ZigBee communication monitoring: ZigBee communications enabled near real-time monitoring can independently interact with other customer procured equipment for near real-time monitoring. This includes the enablement of customer defined settings that notify customers when load changes beyond a predetermined threshold. This functionality is enabled by AMS and displayed through in-home devices;
- Remote firmware upgrades: System-wide implementation of enhanced capabilities can be deployed over time, as well as timely updates to address security threats as identified, without the need for manual intervention; and
- Remote diagnostics: The Company's Meter Operations Center will have a dedicated advanced meter monitoring function that can ping individual meters to test communication pathways and responsiveness.

Capabilities of gas modules only:

- Battery Life: AMS gas modules have a 20-year average battery life while supporting standard data collection patterns (e.g., 15-minute intervals, collected three times daily, with approximately three firmware upgrades throughout its deployment lifespan); and
- Reduced battery life is expected for any meters where alternative advanced data collection patterns have been enabled (e.g., 5- to 15-minute intervals, collected hourly, with approximately three firmware upgrades throughout its deployment lifespan).

[13] Zigbee is a wireless language enabling communication between certain low-power, digital radio devices. See https://en.wikipedia.org/wiki/ZigBee.

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5.5.2 Communication Network

5.5.2.1 Field Area Network (FAN)

Embedded within each meter is a communications module that enables the meter to communicate with Company back-office systems. These modules can either be outfitted with mesh or cellular radios, each of which is best suited to a different set of project economics. Circumstances like population density, topography, seasonal conditions, and other strategic factors may influence the type of communication utilized. By understanding the economic and strategic considerations and combining these modules appropriately, an optimal deployment can be achieved.

5.5.2.2 Radio Frequency (RF) Mesh Network[14]

The radio frequency (RF) mesh network is created by including a low-power, short-range radio in each meter. Each meter is able to transmit its own consumption interval readings as well as a finite collection of data from downstream meters over a secured network connection. All meters with this technology dynamically communicate with each other to identify optimal communication pathways back to centralized data collection points. In doing so, these networks of devices can self-identify the most efficient paths on an ongoing basis and dynamically reconfigure to maintain optimal routing in varying operational situations. It is important to note that RF radiation produced through this process is at levels that have been deemed to be safe for customers. In fact, radiation exposure from smart meters has been shown to be many times less than that of talking on a cell phone.[15]

The Company will utilize radio frequency mesh networks to facilitate meter communication with the backhaul system for the majority of AMS meters. The meters will utilize a relay and router system to transmit the meter data back to the back-office systems, as well as transmit data from the back-office to the meters in the field in a bi-directional manner.

The electric meter and routers will serve as the communications platform for the gas indices. The platform will enable communication between the gas meters and the Company's back-office systems while efficiently optimizing impacts to the gas meter's battery life.

5.5.2.3 Cellular Radio

In certain circumstances, a cellular radio will be used instead of the mesh network. Typically, this technology will be used for customers in areas where reduced population density does not support a mesh network. These meters will instead directly communicate with public cellular

[14] See Appendices A-3.1, A-3.2, A-3-6, A-3.7, and A-3.8

[15] 2011, Edison Electric Institute, "A Discussion of Smart Meters And RF Exposure Issues." pg. 11-15.

systems (e.g., Verizon, AT&T) to transmit consumption data to the Company's back-office systems.

5.5.2.4 Collectors, Relays, and Routers[16]

Collectors, relays, and routers are the equipment that facilitate the transmission of data from the mesh-network-linked advanced meters to the back-office systems. The following is an illustration of how the saturation of individual meters plays a large role in ensuring the collection of all system data: A collector is used to communicate with the meters and transfer the information from the meters to Company computers. But not all meters can reach the collector with their radio signal; these meters then search out a router or another meter in the mesh network to transfer their information to the collector. When one meter communicates through another meter, this is referred to as a "hop." The network is designed to minimize hops, but there will be some meters that may have to hop three to five meters to reach a router or collector to transfer their information back to Company computers. The cause for these hops varies from meters where RF is hard to reach such as a basement or crawl-space, to rural areas where there are long distances between the meter and the collector. With sufficient meter coverage available, there should be many infrastructure configurations possible for the communications network. If there is insufficient meter saturation available, additional routers would need to be installed to ensure adequate network coverage. The transmission of data may utilize multiple types of devices from a variety of vendors, each of which pulls in and transmits data to the next node in the communications pathway on the way to the back-office system.

The collectors, relays, and routers have a number of characteristics that enable communications' efficiency and effectiveness. They are:

- The ability of the network to rearrange itself dynamically to maintain the most efficient communications pathways across seasons, varying weather conditions and vegetation cycles;
- In the event of a power outage, the ability of the FAN to stay up long enough to transmit a power-off notification to alert the outage management system (OMS) of the problem; and
- The inclusion of multiple types of devices that collect and transmit digital interval data:
    - Collectors: larger bandwidth devices for maximum throughput of data to manage data collections;
    - Routers: smaller devices that are used to extend the range of communications for meters and collector connectivity; and
    - Meters: small, short-range devices used to aggregate a small number of meters.

[16] See Appendices A-3.3 L+G Router Data Sheet, A-3.4 L+G C6500 Collector Data Sheet, and A-3.5 L+G C7500 Collector Data Sheets for technical specifications.

5.5.2.5 Backhaul

The backhaul network, which is typically a wide area network (WAN), is the high-speed, high-bandwidth communications structure between the collectors and the AMS head-end. The network can either be public or private depending on several factors, including cost (both initial and recurring), security, meter density in the area, and distance from the existing fiber network.

A private system would have collectors connected to centralized fiber optic or microwave communications infrastructure. A public system would utilize the network of a third-party vendor, typically a wireless cellular carrier, to transmit the data from collectors to the AMS head-end. While a blend of these technologies will be pursued as a pragmatic solution, the majority of communications will occur through the Company's private fiber-optic network as a means to securely transmit the aggregated data from the collectors and routers to the back-office systems.

5.5.3 Systems and Integration – Core AMS[17]

5.5.3.1 AMS Head-End (AHE)

The AMS head-end is the centralized communications aggregation, monitoring, and control system that integrates the communications infrastructure in the field and the back-office systems. The Companies have an AHE system installed for their current AMS Customer Service Offering. This AHE will continue to be utilized for full deployment. The AMS head-end communicates with the advanced meters to collect meter data from reads and events. It also can ping individual meters as necessary and push firmware updates across the network. For electrical systems, it can remotely initiate the connection and disconnection of meters. The AMS head-end system serves as the main point of data collection and dispersal for data being transmitted in either direction, to and from meters.

5.5.3.2 Meter Data Management System (MDMS)

An effective AMS platform requires an MDMS. The MDMS provides advanced meter data storage and archival capabilities for interval meter read information. The MDMS also processes the incoming meter data to ensure sufficient quality. Once the raw data has been processed, it can be utilized by back-office systems like billing, customer service, and certain enhanced data analytics algorithms.

An important function of the MDMS is the "validate, estimate, and edit" (VEE) process. This is a method whereby the MDMS reviews all un-validated data from advanced meters in an effort to identify anomalies and mitigate occasional data gaps. Data may fail preliminary validation because it falls outside an expected range and is flagged for review by metering agents. In

[17] See Appendix 2, Illustrative Application Architecture, for illustration of system architecture for AMS deployment.

addition to failed validations, incomplete or missing interval reads are also highlighted. Flagged data intervals are estimated as the final step of the process and can be updated once additional data has been received or the original data has been validated.

5.5.3.3 Data Warehouse

The data warehouse is the back-office system that is the main archival database for the other systems. It is integrated across the back-office and provides archival support and retrieval functions. Due to the increased volume of information associated with AMS data, the capacity to support data warehouse functionality will need to be augmented accordingly. A fully integrated data warehouse provides the following capabilities:

- Links multiple systems and facilitates data communication;
- Speeds up retrieval as it combines traditionally separate data archives;
- Enables data aggregation and reporting;
- Integrates with customer data presentment services (e.g. web portal); and
- Enables analytic capabilities for insights.

5.5.4 Customer Systems

5.5.4.1 Web Portal

As part of the AMS deployment, the Company will use a web portal that will act as a hub for AMS-enabled customers to view their energy usage, including 15-minute advanced meter interval data. This platform will allow customers to view their consumption data and billing impacts within 24 hours of usage. 24 hours is the soonest data can be made available for customer presentment due to the Company's current processes that translate AMS consumption data transmitted through the RF mesh network into billing quality data. Access to this data will enable customers to make better-informed decisions about how they use energy. As the Company moves forward with AMS, it will continue to evaluate its ability to provide this data sooner than 24 hours after usage when possible. The portal will power customer choice, giving customers the option to enroll in current and future programs that can leverage the more granular data provided by AMS, such as variable pricing programs. Customers can also access educational and safety information, material on energy efficient consumer products, and analysis on home energy usage. The platform may also be integrated with smartphone applications that allow customers to access their data on the go, in addition to being able to create customizable alerts notifying them of grid conditions (including outages, reductions or curtailments), unusual usage, and billing notifications.

5.5.4.2 Green Button Download My Data

Many utilities, including the Company, have implemented Green Button Download My Data. Green Button Download My Data is an industry-led initiative created in response to a White

House call-to-action to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format.[18] Currently, this capability is only available to customers who participate in the Company's voluntary AMS Customer Service Offering. Full deployment of AMS technology would make Green Button Download My Data information available to customers enabled with AMS technology. The Green Button Download My Data system provides the ability to download personal energy consumption data directly to a computer in a secure manner. Data downloaded once AMS has been implemented will be more granular, providing interval consumption data to give customers a better understanding of their energy usage. Additionally, if customers are interested, they can upload their data to a third-party application for further analysis and functionality.

5.5.4.3 Customer Service System

The SAP-Customer Care System (CCS) is a set of applications utilized to manage customer-facing activities. The set of programs pulls meter data to administer orders, billing and payment processing, collections, rebates and discounts for energy efficiency and demand response, and other pricing program rates and usage. As part of the AMS deployment, SAP-CCS will be modified and configured to accept billing data. SAP-CCS will also be configured with parameters to interpret AMS data so that usage can be priced by programs such as time-of-use (TOU). Having such a prominent role in customer interaction with the Company, an effective SAP-CCS with appropriate capabilities is critical to maintaining and enhancing customer satisfaction.

SAP-CCS also includes capabilities intended to foster a relationship with customers and drive customer satisfaction through personalized service. The system pulls from various back-office IT sources to create personal profiles on customers to facilitate customer engagement. For instance, SAP-CCS can be linked with interactive voice response (IVR) to send an automated notification to customers when the system receives a "power-off" notification from advanced meters. Additionally, SAP-CCS will present customer history and near real-time meter status to the Company's customer service representatives when customers contact the Company, giving the Company's employees greater insights to help customers. Service representatives will have a new suite of tools at their fingertips to perform diagnostic services instantly or to ping meters when issues arise. They will also have the ability to restore power that has been disconnected whether it be for non-payment, seasonal usage, or other reasons.

5.5.4.4 Metering Operations Center (MOC) Analytics

The MOC organization will be the central management hub overseeing the day-to-day operations of the advanced meter network, along with its associated communications infrastructure. During the construction and deployment phase of the AMS program, the MOC will develop system-generated reports that will provide information on the communications'

[18] The Green Button Alliance: http://www.greenbuttondata.org

infrastructure, meter deployments, and coordinate to ensure collectors, routers, and meters are communicating. The analysis of the data will assist in the troubleshooting of any meter-related issues that occur during that phase. Once the rollout is complete, the MOC will evolve into the central management hub. Its responsibilities include:

- Proactively manage and monitor advanced meter and field area network performance;
- Remotely investigate and remediate meter and communications infrastructure problems;
- Dispatch technicians or vendors to remediate problems that cannot be done remotely;
- Manage firmware deployments;
- Manage meter exchanges, repairs, maintenance and warranty issues;
- Manage the Meter Inventory Tracking System; and
- Manage the advanced meter shop for the Kentucky and Virginia service territory.

As the Company moves forward with additional grid modernization in future years, the capabilities established for active monitoring of data flows between systems can be further expanded for communications with other devices such as advanced distribution automation (ADA).

5.5.4.5 Meter Asset Management (MAM)

The MAM is the Company's information warehouse for inventory, tracking, and testing of its endpoint devices, including both electric and gas meters indices, and other ancillary metering equipment. The MAM cache holds the relevant information necessary to track an endpoint device across its deployment lifecycle, including, but not limited to, device manufacturer, manufacturer date, installation date and location, serial number, warranty information, geographic information system (GIS) location of service, maintenance log, and any scanned records. The inventory tracking system also reconciles field crew readers with back-office systems and has the capability to store records scanned during any service call by field crews. The MAM includes meter characteristic information that can be linked with the SAP-CCS application to facilitate AMS-enabled functionality. The MAM supports compliance and reporting with Kentucky Public Service Commission mandated meter-testing processes.

5.6 Technology Evaluation

The Company has been monitoring the progression of advanced metering systems since the technology emerged in the early 2000s. With heightened sensitivity to the capabilities and limitations of these devices, the Company has consistently considered the customer experience with regard to its decisions on promoting adoption.

During 2008-2011, the Company conducted the Responsive Pricing and smart meter pilot program and gained valuable experience with the capabilities of the technology. While insightful and demonstrating potentially useful future benefits once the technology matured, the meters and systems of that generation were deemed immature. The marketplace and vendors were rapidly enhancing system functionality which made deployed technologies quickly obsolete. In July 2011, the Company requested cancellation of the program, citing these technology issues and limited customer participation.

A 2013 DNV KEMA study prepared for the Company found that AMS technology had matured significantly since the initial smart meter pilot program.[19] Investigations and ongoing discussions with peer utilities, vendors, and consultants supported this finding. The pace of technology advancements had slowed considerably and the comprehensive set of physical sensors to enable functionality had stabilized. Further, additional algorithmic innovations and analytic capabilities could continue to develop but could be remotely updated on the device without the need for hardware replacements.

In 2014, encouraged by DNV KEMA's analysis of Kentucky AMS feasibility, the Company sought to establish, and the Kentucky Public Service Commission approved, the AMS Customer Service Offering. During this program, which is discussed in greater detail in a later section, the Company tested both radio frequency (RF) mesh and cellular technologies. The Company found that the RF mesh technology was the most reliable, cost-effective technology for its service territory, and has chosen to deploy RF mesh meters to all customers where possible. RF mesh technology also provides the Company with the opportunity to leverage network infrastructure and back-office head end systems that were deployed during the program, lowering some of the costs associated with expansion throughout the service territory.

5.7 Positioning for the Future

AMS represents one of the numerous power service technologies that have become commonplace in recent years, and is a key foundational component for other power service operational capabilities, and customer products and services. Future operations will likely function such that meters perform multiple roles where, in addition to providing billing data, they also act as a coordinated group of sensors throughout the territory. When meters are combined with other operational systems and capabilities that the Company has identified in the 2017 Business Plan but outside the scope of the AMS Business Case, advanced metering data can enhance the value and operations of other business units.

The primary mission of real-time power service operations has been to restore outages as efficiently as possible and coordinate planned outages for maintenance and construction. However, in the context of modern-day customer expectations and technological advancements, a new mission of "grid optimization" is emerging as a parallel to these historical

[19] 2013, DNV KEMA Energy and Sustainability, "LG&E and KU Smart Meter Business Case".

goals. In this sense, AMS data enables more accurate, more efficient outcomes for current capabilities such as locating outages, validating restoration, and managing voltage.

In a broader historical context, it is important to note that the trend toward AMS, and these other optimization capabilities is still relatively new. New market participants, vendors, and consultants have been focused on electrical distribution like never before, resulting from the innovations currently being seen throughout the industry and being considered for implementation at the Company. All indicators point to this trend continuing, if not escalating. While many of the capabilities are known, some capabilities are not yet known or possible to define; however, it is reasonable to expect that use-cases will emerge, utilizing the information available from AMS to enhance operations and lead to the development of new customer services and products.

5.7.1 Advanced Distribution Management System

The Company's ongoing distribution automation (DA) program will install approximately 1,400 electronic Supervisory Control and Data Acquisition (SCADA) system-connected reclosers on approximately 20% of distribution circuits, affecting approximately 50% of customers. The SCADA-connected, intelligent electronic devices (IEDs) will be controlled by an advanced distribution management system (ADMS).

ADMS is the emerging standard software suite used by distribution grid operators. It combines functions of an outage management system (OMS) with functions of a distribution management system (DMS) and the SCADA system. While the functions of an ADMS are numerous, only a subset are covered in this report as applicable to AMS.

One of an ADMS's core capabilities is to consolidate pertinent data from, and exert real-time control over, a variety of IEDs such as reclosers, capacitor banks, load tap changers, voltage regulators, and fault current indicators. These devices can be coordinated by the ADMS to provide greater capabilities than what would be achievable if each device were to operate independently. Two notable functions are:

- Fault Location, Isolation, and Service Restoration (FLISR), and
- Volt/VAR Optimization (VVO).

AMS enhances both of these functions by providing additional data points for computation and algorithmic adjustment. AMS data can improve the load profiles and powerflow calculations used by FLISR. Similarly, AMS supports VVO by providing voltage at each metering point across the length of the circuit. These voltage points create a voltage profile that allows for tighter control of voltage, within acceptable limits, resulting in energy savings. Both of these potential functions are discussed in more detail in the following sections.

5.7.2 Volt/VAR Optimization & Distributed Energy Resources

VVO represents a family of optimization algorithms that can be deployed during various situations to improve operational characteristics. By monitoring and controlling capacitor banks, voltage regulators, and load tap changers, VVO algorithms can in some cases reduce energy consumption for all customers on a circuit by two to three percent without negatively impacting the customer experience. The operation of this function can be highly automated or initiated by direct operator intervention.

Should the Company decide to pursue the functionality, AMS can assist in the ability to monitor grid conditions and automatically regulate power flow. Distributed energy resources (DERs), especially rooftop solar, have become more economical and efficient in recent years. In certain areas of the country, DERs have experienced substantial grid penetration, and this trend is expected to continue if not increase. While DERs have many benefits, the distribution network was not initially designed with non-point power sources or distributed resources in mind. Even though there is a certain robustness to the systems, over time, especially with greater DERs penetration, volatility of power flow will increase (i.e., solar photovoltaics supplying power only during the day) and will make optimization all the more important. VVO can provide several benefits:

- Higher level of an operator's visibility into system operating parameters;
- Greater control over reliable and consistent energy delivery; and
- Greater control over optimizing energy efficiency, thereby saving customers' money.

Advanced meters can enhance VVO further by designating a specific subset of meters as "bellwether" meters. A bellwether meter is one that is configured to provide additional voltage data with greater frequency. They are particularly useful when placed at the end of a circuit where they perform as an end-of-line voltage monitor. This additional information can be leveraged in VVO calculations to refine VVO adjustment algorithms further and ensure that no customers experience a voltage violation.

5.7.3 Fault Location, Isolation, and Service Restoration (FLISR)

FLISR is a capability that coordinates substation equipment, circuit reclosers, and wireless communications' infrastructure through analytic algorithms to decrease the duration of and the number of customers affected during outages. FLISR leverages data compiled by SCADA from various devices along the distribution network and computes the estimated location of a fault on a given circuit. In response to this determination, it can coordinate the operation of IEDs to reconfigure distribution circuits and minimize the impact to customers. FLISR can propose a series of actions for control center operators to adjust and authorize, or FLISR can run in an automated mode that does not require operator intervention. Field crews must ultimately be dispatched to repair any damaged sections of distribution circuits, but fewer customers are impacted in the interim.

For FLISR to operate properly, the ADMS requires a variety of data. Two data points AMS will positively impact are the customer load profiles and powerflow calculations. Without AMS data, the FLISR calculations will use static data to determine the best switching solution. With the timely and accurate data from AMS, the FLISR calculation will be able to determine a better switch plan than it could with static data to possibly restore more customers.

AMS will be particularly helpful in identifying timely, efficient, and accurate outage locations on non-DA circuits. Meter communication will be able to replace the reliance on customer contacts for this information.

Whether the restoration is automated via ADMS or performed manually, AMS data will be useful in identifying nested outages and confirming the customer's service has been restored.

5.7.4 Distributed Energy Resource Management Systems (DERMS)

Distributed energy resource management systems (DERMS) are a suite of applications that integrate and manage DERs across the grid. DERMS can be an independent system or a module of an ADMS. It relies on open protocols to leverage as much of the existing infrastructure as possible and facilitates next-generation coordination between in-place components, such as advanced meters, DA and substation devices, ADMS, DR devices, and advanced inverters, to provide additional control of the distribution network. As previously reported, with the potential for DERs to have significant impacts on the grid, DERMS will further enable efficiency and reliability. Advanced metering can be used for two key functions within this system: demand response support and distributed generation support.

5.7.5 Demand Response Support

Defining explicit characteristics of the Company's demand response (DR) program was not part of this AMS assessment. However, as the Company moves forward and considers offering additional programs of this sort, it is possible to look at other programs available throughout the industry to identify commonalities for how advanced metering is leveraged.

DR programs are dependent on customers participating at certain times when needed, with compensation dependent on levels of participation. For certain types of programs, AMS enables participation by allowing bi-directional messages to be sent from the utility to a premise, requesting curtailment accompanied by an acknowledgment or confirmation once curtailment has occurred. In other programs, AMS may not include the curtailment notification. In either case, AMS captures interval data for both baseline consumption (that which is used on other comparable, non-event days) as well as event-specific consumption (showing consumption levels at intervals immediately before, during, and after events) which can jointly be used to measure curtailment performance during events. By capturing this information, it is possible to present performance measures to customers more quickly for internal analysis and budgetary consideration.

5.7.6 Other DER Support

Distributed energy resources (DERs) are gaining traction throughout the country with customers of various sizes as the economics of the technology involved become more affordable. In particular, rooftop solar photovoltaics (PV), energy storage, fuel cells, and plug-in electric vehicles (PEVs) are experiencing greater market penetration. Collectively, these assets represent a fundamental shift away from a centralized power delivery framework as each can also support bi-directional power flow by injecting surplus energy into the grid.

In one context, integration of these assets introduces dynamism which the Company will seek to manage in order to ensure safe and reliable power for all customers. Advanced metering could be connected to each DER to provide enhanced real-time monitoring and allow for more nuanced control of the distribution grid in response to changing operational characteristics.

In another context, advanced metering for each DER allows for highly granular usage data to complement existing net metering structures. When paired with evolving time-of-day rates, new and mutually beneficial approaches could emerge which incentivize new customer behaviors better aligned to the intermittent and variable nature of these resources.

5.8 Web Enhanced Customer Experience Programs

AMS technology brings numerous benefits to the customer experience as part of the program currently envisioned. Certain other potential customer benefits would require follow-on evaluation and would be better pursued once the AMS technology is fully deployed and stable. These capabilities fall into two broad categories: modifications to existing programs and new capabilities.

5.8.1 Conceivable Modifications to Existing Programs

The Company has always sought to provide the best customer experience possible. Over the years, the Company has established and maintained a number of successful programs that have proven to be very popular among many groups of customers. Existing programs that could benefit from AMS implementation include:

- Demand Conservation – Today, customers voluntarily enroll in the Demand Conservation program and receive monthly bill credits in return for allowing the Company to briefly interrupt their electric supply through devices installed on specific appliances (i.e., central air conditioning unit, heat pump, electric water heater, or in-ground swimming pool pump). This curtailment has proven to reduce peak demand across all customers and has been highly beneficial in stabilizing energy delivery. What is less clear is the reduction level and consistency for individual customers. Through the use of AMS data customers can gain greater insight into their own consumption patterns, to better evaluate the potential impact of participating in the Demand Conservation program. Future programs could be stratified giving greater incentives to customers whose conservation efforts are most dependable or provide the deepest reduction in peak usage.

- We Care – Income-eligible customers receive an in-home energy assessment. Once the assessment is complete, customers are eligible to receive various energy efficiency improvements performed on their home at no additional cost. Empowering customers with more AMS-enabled information about their usage could help them, or those who advocate and assist their needs, to better understand the impact these improvements have on their bill and other ways to save.
- Residential Time-of-Day (TOD) Rates – Granular consumption data could allow customers to view their energy usage during peak and off-peak hours to better evaluate whether TOD rates can benefit them. One example of TOD rates is the optional Residential Time-of-Day electric energy rate the Company introduced in 2015. Customers on this rate have the ability to reduce their overall electric bill by shifting their electricity use to a lower cost time period during the day. Not only could AMS data allow customers to view potential savings that can be realized by enrolling in TOD rates, it could also empower them to investigate behavioral changes that could increase potential savings.
- Green Button – "Green Button Download My Data" has been implemented by the Company as well as many utilities around the country to provide a standardized format of AMS interval data for use by customers. The next generation protocol entitled "Green Button - Connect My Data" allows customers to authorize the Company to provide their interval data to customer authorized third parties. Through the Green Button initiative and AMS implementation, future tools and functionality could be developed that enable customers to work with the provider(s) they find to be most impactful based on their specific needs.

5.8.2 New Capabilities

The Company is also investigating potential new customer programs that are not possible without AMS implementation. Examples include:

- Predictive Usage Alerts – AMS could enable customers to set alerts that notify them when they are approaching a certain usage or bill amount. AMS technology can have the ability to predict monthly usage based on customers' past usage history and recent trends. This can enable customers to make behavioral changes before the end of their billing cycle in order to better control their energy costs.
- Pick Your Own Due Date – By shifting from monthly reads to daily, AMS-enabled reads, the Company will have usage information available throughout the month. This service is not currently available, due to the manual, periodic nature of collecting metering data. With AMS-enabled data, the Company consistently has a customer's consumption data; therefore, customized changes to due dates can be implemented. This allows customers the ability to pick a bill due date that is convenient for them, have it applied on a date of their choosing, and gives customers greater control over their finances to assist them in their unique financial situations.

6 AMS Customer Service Offering

6.1 Vendor Evaluation

The Company has a long history of evaluating vendors for different operational needs and implementing emerging technologies to improve service reliability, operational efficiency, and customer service. The Company evaluates vendors through a competitive bid process to ensure technologies and services are provided at the lowest possible cost while providing the capabilities necessary to maximize customer benefits.

For full-scale AMS deployment, the Company has chosen to partner with Landis + Gyr. Landis + Gyr has experience deploying advanced meter technology at other large utilities and has successfully worked with the Company numerous times in the past.

Examples of relevant successful Landis + Gyr projects include:

- Landis + Gyr Experience: Landis + Gyr has successfully deployed advanced meters across the globe. In North America alone, Landis + Gyr has deployed approximately 25 million meters. Within the United States, these deployments have been implemented by utilities across the country ranging in size and up to 3.3 million meters, and primarily utilizing the same RF mesh technology the Company will deploy in its Kentucky service territory.

- LG&E Downtown Network: In 2014, Landis + Gyr was awarded a contract to deploy approximately 1,500 advanced meters in the downtown Louisville area. Landis + Gyr was chosen from a field of five bidders that were all evaluated using the same criteria and methods. The final selection of Landis + Gyr was based on low costs combined with their ability to meet all necessary requirements. These advanced meters and the supporting infrastructure were successfully deployed in 2014 and continue in operation today. With full AMS deployment, these meters will seamlessly integrate with new AMS infrastructure.

- AMS Customer Service Offering: In 2015, the Company reviewed four bids to supply meters, infrastructure, and services for up to 10,000 Company customers who voluntarily opted in to the AMS Customer Service Option (also referred to as "AMS Opt-In" herein). Bids were evaluated on cost and operational fit for the AMS, with consideration given to the vendor's ability to provide a solution that would seamlessly integrate with a future full-scale AMS deployment. Landis + Gyr and Itron were both awarded contracts. Landis + Gyr provided RF Mesh network technology for metro service areas and Itron provided cellular network technology for the surrounding areas.[20] Both companies were the lowest cost options and Landis + Gyr specifically demonstrated the ability to leverage existing network assets implemented during the LG&E downtown network project. A recent survey of program participants demonstrated overwhelmingly positive feedback from the customers polled and can be found in Appendix A-1. The Landis + Gyr equipment used as part of the Opt-In program has established a foundation for full deployment of AMS and will be integrated into the larger system.

- PPL Electric Utility (PPLEU) AMS Deployment: Landis + Gyr was selected out of a field of various providers to supply advanced meters, supporting infrastructure, and MDMS system software. This deployment is currently in progress, utilizes the same technology proposed by the Company throughout this document, and allows intra-company communications and learnings to increase deployment efficiencies.

Landis + Gyr's nationwide AMS experience and familiarity with the Kentucky service territory characteristics make them an ideal partner for full AMS deployment. In Kentucky, Landis + Gyr

[20] At the time of the contract award Landis + Gyr did not have an acceptable cellular option. Thus, Itron was selected to provide cellular meters for opt-in customers in rural areas outside of an RF Mesh deployment. Landis + Gyr has since developed an advanced cellular option that is under evaluation.

provided the AMI equipment for Kenergy's AMI deployment,[21] and Grayson Rural Electric Cooperative Corporation has proposed to use Landis + Gyr as its AMI provider, as well.[22]

It is important to note that all discussions and negotiations with Landis + Gyr are conceptual at this point and costs included in this plan are estimates only. The Company is developing detailed plans and will begin execution of work with its partners. The Company continues to explore opportunities to take advantage of the scalar benefits of an enterprise-AMS deployment, including volume discounts, performance-based pricing, and opportunities to leverage existing network assets.

6.2 AMS Customer Service Offering and Results

In Kentucky PSC case number 2014-00003, the Commission approved the Company's AMS Customer Service Offering as a way to further evaluate AMS technology. The approval stated that "customers benefit from smart meters because they have a level of information at their disposal that allows them to control their energy use and, therefore, exercise more control over their utility bills." In 2015, the Company implemented this program for customers who elected to voluntarily opt-in. Deployment commenced in November 2015 and was capped at 10,000 advanced meters. To date, the Companies have enrolled over 7,300 customers in the AMS Customer Offering.

This preliminary AMS infrastructure includes meters, routers, collectors, head end, meter asset management system, and integration with ePortal. Every opt-in customer is provided an AMS enabled meter, access to their meter read interval data through ePortal, and educational materials on ePortal functionality. Deployment has progressed with minimal issues. In May 2016, the Company partnered with Bellomy Research (a third-party marketing research company) to conduct a customer survey evaluating AMS opt-in customers' perceptions.[23] The survey showed positive results including:

- Customer Satisfaction: A large percentage of program participants were satisfied with their AMS service (77%) and the ePortal (75%). The majority of respondents rated their overall satisfaction with AMS as Highly Satisfied (58%).

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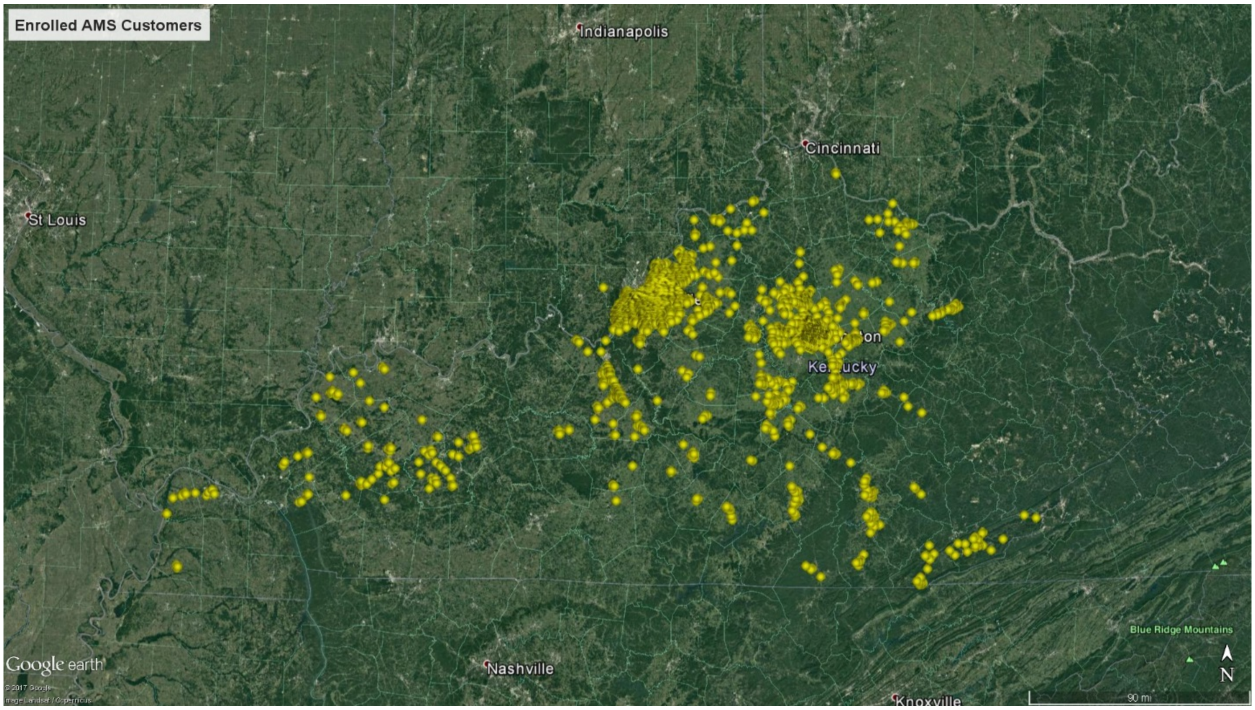
[21] *In the Matter of: the Application of Kenergy Corp. for an Order Issuing a Certificate of Public Convenience and Necessity*, Case No. 2014-00376, Application (Oct. 27, 2014).
[22] *In the Matter of: the Application of Grayson Rural Electric Cooperative Corporation of Grayson, Kentucky, for Commission Approval pursuant to KRS 807, KRS, 5:00001, and KRS 278.020 for a Certificate of Public Convenience and Necessity to Install an Advanced metering Infrastructure (AMI) System*, Case No. 2017-00419, Application (Oct. 24, 2017).
[23] See Appendix A-1, Advanced Meter Service Participant Study - Bellomy Research, pg 7-40.

- Customer Engagement: Most customers took additional steps to lower their energy consumption, including upgrading to LED light bulbs, programming thermostat settings, and enrolling in the Company's energy efficiency programs.
- ePortal Usage: The survey showed a positive relationship between increased ePortal usage and customer satisfaction. Customers who used the ePortal more frequently were much more likely to be satisfied with the overall AMS program. A 2017 survey of the Companies' customers also supported this finding,[24] as did a 2017 analysis by third-party vendor Tetra Tech concerning active users of MyMeter (ePortal for the AMS Opt-In).[25]
- Areas for Improvement: Most observations from program participants highlighted program elements that could be improved with full deployment, rather than a lack of interest or disagreement with the core capabilities provided. These included:
  - Ease of Access – The most frequent comment from customers revolved around having to log into their utility account, search to find the meter data within the Company website, and the lack of a mobile app. These are all areas the Company plans to explore and improve upon to make it easier for customers to view and analyze their data.
  - Customer Education – Some customers expressed that they did not understand how to navigate the ePortal or did not understand the consumption data. The Company is exploring ways to improve customer education to address these concerns and improve customer satisfaction.
  - Timeliness of information – During the program, ePortal information was updated daily with 15-minute interval data. Customers expressed the desire to see this information sooner than daily. Generally, the feasibility of doing so is not currently economically possible. However, the Companies continue to explore technologies that could provide customers with this information.
  - Information Display in $ Terms – 86% of customers expressed interest in having the option to view ePortal information in dollar terms in addition to the current consumption (kWh). This functionality was later implemented by the Company in 2016.

The Company's AMS Opt-In customers are geographically diverse, spanning various topographies, population densities, and socio-economic segments throughout the Company's

[24] *See* Appendix A-9, AMS Opt-In Online Customer Survey (June 2017).
[25] *See* Appendix A-10, Tetra Tech 2017 Analysis of AMS MyMeter Active Users.

service territory. The distribution of enrolled AMS opt-in customers as of November 13, 2017 is shown below:



Collectively, all data points resulting from experiences to date indicate that a full-scale AMS deployment represents a logical expansion of the AMS Customer Service Offering.

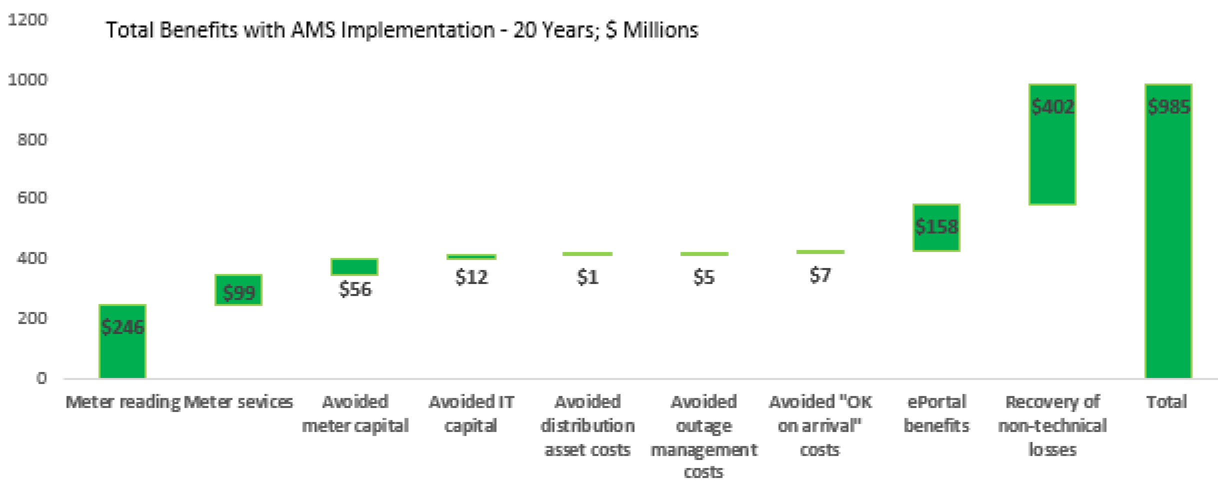
7 Benefit-Cost Analysis

A significant change to the benefit-cost analysis presented in this AMS Business Case is the inclusion of projected impacts of offering customers the ability to opt out of AMS. Based on industry information concerning opt-outs from advanced-metering deployments, the Companies have assumed a 0.8% opt-out rate in all calculations.

7.1 Benefits

As demonstrated by the AMS Customer Service Offering, these technologies enable many direct and indirect benefits that contribute to an improved customer experience. The Company plans to achieve these benefits by deploying meters throughout the rest of its service territory. The scale of a full deployment, continuing technological advancements, and numerous capabilities to monitor and control meters allows the Company to realize improvements in both operational and customer experience.

The expected benefit categories include reduced meter reading and services support, avoided capital and O&M costs, improved outage identification and management, reduction of non-technical losses, and reduced energy costs to customers due to using improved consumption data to lower usage. Total benefits are estimated to be $985 million over 20 years. A breakdown of individual benefit categories is shown below[26]:



Specific qualitative benefits and financial estimates are the result of a cross-functional analysis effort involving different groups at the Company including Customer Service, Meter Assets, Meter Reading, Field Services, Billing Integrity, Information Technology, Distribution Operations, and Corporate Safety. These benefits are discussed in greater detail below.

7.1.1 Improving Customer Interactions

First and foremost, AMS is one of the key initiatives at the heart of the Company's efforts to enhance its position as the Trusted Energy Partner for its customers in Kentucky and Virginia. AMS provides the Company with the ability to considerably improve the level of information it has about the customer experience. This information, combined with the Company's unique position to interpret and present this information to customers in ways they find impactful, presents an opportunity to inform and empower customers.

7.1.1.1 Customer Empowerment via ePortal

As part of the AMS infrastructure deployment, the Company will continue to offer an ePortal that will enable customers to access their electric and gas consumption data, among other products and services. Due to the increased granularity and access to data, these capabilities will be available to many more customers. Customers will be able to see historical energy usage data from which their usage trends and patterns emerge, allowing energy saving tips and insights to be presented. This access will enable customers to make more informed decisions

[26] For greater detail regarding methodologies and supporting data of all cost and financial benefit breakdowns, see Appendix A-5 AMS Business Case Summary Presentation, and Appendix A-6 AMS Capital Evaluation Models.

on their energy usage through visualization of energy conservation-driven behavior changes. The ePortal website will be the hub of educational and safety information, along with material on energy efficient consumer products.

Preliminary opt-in program results show that active users of these types of tools find tremendous value in having access to this detailed energy usage data. The Company considers a user to be “active” if the customer accesses the available data six times or more. These active users draw insights from their consumption patterns and adjust their behavior to save energy. Based on a Smart Grid Consumer Collaborative (SGCC) report showing that a 5 to 15 percent reduction in electric usage is consistently found for active users,[27] the Company conservatively projects 3% energy savings on the average monthly residential bill for active users who make proactive changes to their energy usage. If the Company extrapolates these projected savings across the total 2016 set of AMS Opt-In participants, their assumptions yielded an overall savings rate of 0.5 percent savings across all AMS enabled residential customers (0.48 (customers who access ePortal data) x 0.36 (active users of ePortal data) x 0.03 (projected energy savings) = 0.005). While AMS is planned for most customers to receive advanced meters, the aggregate consumption benefit was limited to 0.5 percent of residential electric consumption only. Any possible additional energy consumption reduction by other customer classes was not counted in the Company’s analysis. For residential electric AMS enabled customers who proactively change their energy usage patterns as a result of the ePortal information, a savings of approximately $158 million over 20 years can be realized.

7.1.1.2 Call Center and Customer Service

The Company initially expects a modest increase in customer inquiry call volumes during the implementation of AMS and welcomes the opportunity to directly address customer questions about the AMS implementation. As time progresses, this higher call volume is expected to drop below current levels as customer education efforts and self-service trends on the ePortal are established.

AMS will also provide incremental experiential benefits in the ongoing customer operations area. By embracing these new technologies, AMS gives new tools to customer service representatives to more quickly and effectively help customers. Customer service representatives (CSRs) will have access to a host of additional tools and capabilities such as:

- Customer Usage History – CSRs can access each customer’s history and detailed electric and gas interval usage data to establish context about a particular customer, better anticipate customer concerns, and provide details to customers who might not have ePortal access or need assistance interpreting the information.

[27] See Appendix A-7, Smart Grid Consumer Collaborative, “Smart Grid Economic and Environmental Benefits,” at 30.

- Rate Information – CSRs will be able to view a customer's granular usage data to recommend optional rate plans that better meet their energy management needs.
- Real-time diagnostics – CSRs will be able to ping customer-specific meters in real-time to run basic diagnostics and more quickly determine the nature of an issue. In some cases, CSRs will be able to determine if an outage is electric distribution system-related (i.e. before the meter) or behind the meter.
- Real-time Account Services – CSRs will be able to obtain real-time meter reads to aid in customer billing inquiries or assist customers moving into or out of their premise as well as other account-related details. Today, most of these activities are dependent on scheduling an appointment and having a technician physically visit the premise. Today these functions take hours or days to be completed.
- Real-time Remote Service Switching – CSRs will have the ability to reconnect electric meters in real-time when customers start service, pay outstanding bills, or reestablish service after a temporary disconnection.

7.1.1.3 Improved Billing Issue Resolutions

Strong internal billing processes flag anomalous billing determinants to identify and correct data to ensure accurate billing. Staff then manually process these exceptions, researching them through a variety of means to confirm accuracy. This process can take multiple days and sometimes requires a field technician to physically inspect the meter. AMS technologies will streamline this process, lowering the need for current follow-up levels through automation and data analytics.

Additionally, the Company currently estimates approximately 2.5% of meter reads while in the process of reading a meter. AMS will lower the number of these instances and, when necessary, will provide more accurate estimates. Currently, when billing reads are not available the Company estimates the reads based on the previous months' reads. AMS will provide daily reads throughout the month allowing for better estimation during those times when actual billing reads are not available.

The Company has chosen not to quantify these benefits due to the fact that its current processes have driven low levels of billing corrections and meter reading estimates. Nonetheless, the Company believes there will be improvements associated with this process that will lead to increased customer satisfaction.

7.1.2 Enhanced Distribution Grid Efficiencies

AMS technologies enable enhanced distribution grid efficiencies in a number of ways by helping operations to "get the lights on" as fast as possible. Some of these approaches are as follows:

7.1.2.1 Avoided Distribution Asset Costs

Using AMS data for transformer load management, some distribution transformer failures may be predicted earlier. This earlier identification can allow the Company to move from time-based maintenance to condition-based preemptive repair or replacement of the failing transformer before it fully fails, thereby reducing the outage duration and avoiding any additional cost of an "emergency" replacement. The Company estimates a savings of $1 million over 20 years.

7.1.2.2 Automated Outage Reporting and Shortened Restoration Times

AMS technologies can proactively report when power outages have been detected for individual meters. This allows earlier detection of outages with more information available to the Company's Outage Management Systems (OMS). This data will help the Company identify the location and extent of outages which supports a more rapid, effective coordination of restoration efforts. Faster, more targeted restoration activity translates into decreased crew time, overtime savings, reduced fleet costs, and lower contractor expenditures representing total savings of $4.6 million over 20 years based on a 10% reduction in outage duration and fleet costs.

7.1.2.3 Reduction of "OK-on-Arrival" Instances

AMS technology will reduce the number of instances in which a crew is dispatched to a reported outage, but arrives on-site to find utility-responsible services operating properly. AMS technologies can alert dispatchers that an experienced outage has elapsed or that outages are "behind the meter" and would better be resolved by a customer's electrician. The Company expects to eliminate 3,400 per year "OK-on-Arrival" instances, reducing fleet and crew time, which represents a savings of $7.1 million over 20 years.

7.1.3 Enhanced Metering Operations Efficiencies

AMS technologies enable enhanced-metering operations' efficiencies in a number of ways by helping to streamline, automate, and improve many of the capabilities already being performed.

Current meter systems require the Company to manually read meters on a monthly and an ad hoc basis. AMS allows the Company to read meters remotely through over-the-air network communication in a manner that is faster and more efficient than the current manual effort. This will allow the Company to realize savings through the elimination of nearly all manual meter reading once meters and the necessary infrastructure are operational, saving employee overtime and decreasing contractor usage.

Current meter reading processes also include physical inspection of meters while onsite. Additional savings can be realized by reducing these physical inspections from a monthly basis to the regulatory-required timeline of two and three years for electric and gas meters respectively. Additional savings could be realized if the Kentucky PSC relaxed current physical meter inspection requirements in response to the installation of AMS meters.

In total, reduced manual meter readings represent savings of $246 million over 20 years.

7.1.4 Reduced Staffing for Ad Hoc Field Services

Current meter systems also require the Company to manually visit certain premises on an as-needed basis in response to customer circumstances. This can include, but is not limited to, off-cycle meter reads, meter re-reads, move-in connections, bill payment reconnections, and disconnections resulting from various causes. AMS technology provides automation potential for these and other situations. By enabling bi-directional wireless communications for these functions, CSRs will be able to perform these functions in real-time and a physical visit by a field technician will no longer be required. The Company does not anticipate any reduction in Company staff positions; however, a reduction of internal overtime and external contractor spend as a result of AMS technology implementation is estimated to be a savings of $99 million over 20 years.

7.1.5 Recovery of Non-Technical Losses (NTL)

The Company's estimated savings due to increased identification of non-technical loss causes is based primarily upon the Electric Power Research Institute (EPRI) study titled "Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future."[28] This report describes the fact that a utility's ability to deliver energy is limited to its gross generation less technical and non-technical losses. Stated another way, the Company is able to calculate the amount of energy it generates; however, not all the energy generated by the Company can be delivered to a customer or directly attributed to the customer who consumed the energy. This unbillable energy is considered lost. The cost of lost energy is socialized across the Company's rate base. This lost energy can be further separated into two categories: technical losses and non-technical losses.

Technical losses occur as the Company's generated energy is transported over the transmission and distribution systems. The technical losses are a result of the physical characteristics inherent in the electrical system itself and result in energy that cannot be delivered to customers for use.

Non-technical losses are not related to the physical characteristics of the system but are related to the company's inability to identify the individual customer consuming the energy. Non-technical losses arise from things like "non-performing and under-performing meters, incorrect application of multiplying factors, defects in current transformer (CT) and potential transformer (PT) circuitry, non-reading of meters, pilferage by manipulating or bypassing of meters, and theft by direct tapping, etc."[29] The Company has not previously had the tools to adequately identify and proactively address the problems associated with non-technical losses. As a result

[28] *See* Appendix A-8, EPRI, "Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future."
[29] *See id.* at 1-3.

of this inability, there are customers who do not pay for some or all of the energy they receive leaving all of the Company's Kentucky customers subsidizing the losses as part of their rates.

AMS technology and Data Analytics will provide the Company with additional tools that can help to take steps to reduce some of these losses by attributing a portion of them directly to their cause. AMS capabilities embedded within each meter coupled with revenue protection analytics can assist in identifying non-technical revenue loss resulting from usage anomalies such as theft, meter configuration errors, or meter malfunctions. Examples of anomalies include intermittent outages coupled with usage reductions indicating physical meter breach or bypass (e.g., tilt, rotation, and reverse flow), anomalous load profile with statistically significant variation indicating meter disabling, consumption on inactive accounts, and anomalies or meter events suggesting meter malfunction or configuration error (i.e., measurement errors and missing interval data). The EPRI study states that "(i)ntegrated with meter data management system (MDMS) technology — software that accepts, stores, and forwards AMI-collected data to utility systems such as billing — AMI significantly improves a utility's ability to monitor customers' electric meters and detect both intentional electricity bypasses and unintentional errors (e.g., billing and customer service problems encountered by traditional manual meter-reading operations)."[30]

The EPRI study goes on to summarize that "(e)stimates of non-technical revenue losses range from 0.5% to 4.0% of annual revenue," but concludes that "(n)on-technical revenue losses most likely fall within a much narrower range: 1.65% to 2.15%, depending on the utility and service territory… A 'mode' of 2% would appear reasonable and reflective of the impact on distribution utilities."[31]

The Company applied the recommended 2% to the projected annual electric revenues less the forecasted revenue of out-of-scope customers. Although AMS is a significant enhancement to the available tools used to identify these non-technical losses, the Company does not expect to be able to identify and recover all of the instances where a customer is not currently paying for some or all of the energy they consume. In light of this inability to detect all NTLs and the Company's discussions with other utilities, it estimated that 60% of these non-technical losses could be identified by AMS technology and data analytics. Based on Company recovery experience associated with tampering fees billed versus those collected, the Company believes it will be able to recover 60% of the identified costs associated with the currently unbilled energy from the customer who actually consumed the energy, thereby reducing the amount being spread over the entire customer base:

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

[31] 2008, EPRI, "Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future" p. 1-18.

LG&E-KU Combined	2014	2015	2016	2017 YTD[32]	Total 2014-2017
Tampering Fees Billed	$380,620	$418,578	$386,947	$288,721	$1,474,866
Tampering Fees Collected	$234,630	$246,639	$215,411	$163,552	$860,232
Recovery Percentage	62%	59%	56%	57%	58%

The end result is a net customer benefit from a more equitable system, where the true responsibility of payment is borne by the parties responsible for the energy usage. Depending on factors such as the percentage of meter errors, the percentage of theft discovered, and the percentage of revenue that can eventually be recovered, non-technical losses recovered can be significant. The Company estimates recovery of non-technical losses to be $402 million over 20 years.

7.1.6 Avoided or Deferred Capital Costs – Meter Replacements

Implementation of AMS meters reduces the need for legacy, both electro-mechanical and electronic non-AMS enabled, meters that were budgeted for replacement in coming years due to their anticipated end-of-service life. As the AMS deployment commences, non-AMS meters taken out of service can be retired or used as replacements in areas that AMS has not been made available or for customers that have opted-out of AMS. This provides the Company with flexibility to address operational and customer service issues that may arise during deployment. Any AMS meters failing shortly after deployment will be replaced by the AMS vendor under warranty. Meter failures through the remainder of the business case period will likely continue, but at a lower failure rate due to the average service age. Collectively, this lowered replacement spend represents $56 million in savings over 20 years.

7.1.7 Avoided or Deferred Capital Costs – Information Technology

AMS implementation allows the Company to avoid or defer certain costs related to IT applications that will be impacted by AMS technologies. Identification of these costs was performed thoughtfully to ensure that avoidance or deferral of these costs would cause no detriment to the customer. Impacted programs include the elimination of the cyclical meter reading hardware refresh purchases, deferral of Customer System enhancements and upgrade cycles, avoided upgrade costs for the mobile work management system, and various other identified benefits. In total, these programs represent approximately $12 million in IT savings over 20 years.

[32] 2017 Tampering Fee Data is through November 2017.

7.1.8 Improved Meter-Related, Utility Staff Safety

Safety and health are core values of the Company. The ability to reduce exposure to injuries through AMS directly supports the Company's goal of zero accidents and no adverse impacts to the public, employees, and contractors.

For instance, manual meter reading and related services can expose Company employees and contractors to unsafe conditions with extensive travel time and encounters such as hazardous stairs or unrestrained animals. Safety incidents, including threats, require the attention of a number of employees that are called into action. This involves ensuring the safety of the employee, investigating the circumstances, and reporting the incident to the local authorities and to the Kentucky Public Service Commission. The Electrical Technical Training and Public Safety department estimates that between 37 and 58 employees are called in response to a safety incident. Since 2011, Field Services' personnel have averaged about 80 physical threats per year related to service disconnections. Throughout 2017, the Company received 96 threats related to service disconnections, continuing a concerning trend across the Company of increased threat levels.

AMS implementation would reduce these events, improving employee productivity and increasing safety. Proper safety policies and procedures minimize these instances and they can potentially create a relative reduction in personnel costs over time, which will benefit customers. Therefore, though the Companies have not attempted to quantify these benefits, they are real benefits of AMS generally and its remote service switching capability specifically.

7.1.9 Environmental Benefits

AMS provides environmental benefits for the future. Remotely reading meter data certainly enables lower transportation emissions from less mileage and fewer premise visits. In addition, customers will obtain the opportunity to better understand their usage and decrease emissions of carbon dioxide (C02) from lower energy consumption. AMS can also provide a foundation for measuring data that may be required for meeting CO2 reductions from any future state-wide or federal greenhouse gas' (GHG) regulations.

7.2 Costs

The Company's cost projections carefully consider the preliminary deployment and on-going expenses necessary to implement and operate the various components of AMS technology across its service territory. Development of these detailed estimates resulted from robust and extensive analysis efforts, which included consideration of the following:

- Inclusion and refinement of costs the Company incurred as part of its current AMS Customer Service Offering;

- Assumptions, contractual indications, and cost outlays articulated by peer utilities, including PPLEU;
- Estimates provided by internal subject matter experts across numerous business units;
- Budgetary estimates from potential vendors;
- Assumed cost efficiencies resulting from a similar PPLEU vendor and architecture;
- Assumed cost efficiencies resulting from concurrent deployment of electric meters and gas indices; and
- Reviews with external consultants for high-level, overall reasonableness and comprehensiveness.

Results from this methodical process give the Company confidence that it has fully considered costs for meters, mesh and cellular communications, data backhaul, core information technology systems (configuration, enhancement, and integration), customer outreach and education, employee change management, and overall program management. These cost categories were then further modeled to fully consider various financial impacts, such as deployment rates, inflation, depreciation, and costs of capital.

The Company forecasts a total capital expenditure of $320 million through the current 2018-2022 business plan, which includes a contingency amount of $27 million. During this time frame, AMS capabilities will progressively become operational, and thus operational and maintenance expenses are incurred. Operations and maintenance (O&M) expenses across this same period are budgeted to be $30 million. The capital and O&M annual spend for this phase of the program is shown below:

COMPANY TOTAL	Total Nominal $ 2018 - 2022	2018	2019	2020	2021	2022
Capital Costs						
Meters	$ 188,134	$ 4,535	$ 77,928	$ 101,819	$ 3,852	$ -
Network	$ 18,509	$ 2,684	$ 15,192	$ 624	$ 10	$ -
IT and Systems	$ 113,392	$ 23,515	$ 55,535	$ 32,081	$ 2,261	$ -
Capex total	$ 320,035	$ 30,734	$ 148,656	$ 134,523	$ 6,122	$ -
Operating Costs						
Meters	$ 17,092	$ -	$ 4,701	$ 9,772	$ 2,238	$ 381
Network	$ 1,623	$ -	$ 367	$ 408	$ 419	$ 429
IT and Systems	$ 11,104	$ 100	$ 1,201	$ 2,674	$ 3,267	$ 3,862
Opex total	$ 29,818	$ 100	$ 6,268	$ 12,854	$ 5,924	$ 4,672
Total Costs	$ 349,853	$ 30,834	$ 154,924	$ 147,377	$ 12,046	$ 4,672
Total Benefits	$ 112,908	$ 2,318	$ 11,508	$ 22,707	$ 37,322	$ 39,053

PPL companies

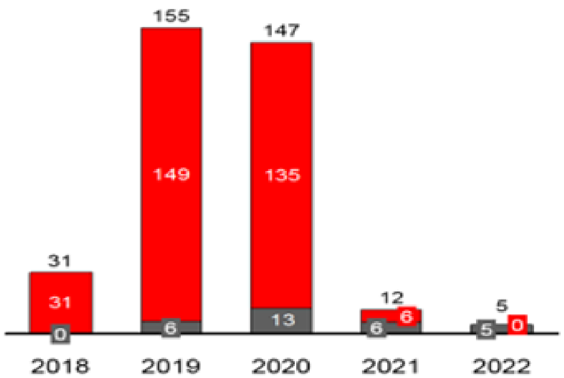
AMS Cost-Benefit Summary (2018-2040)

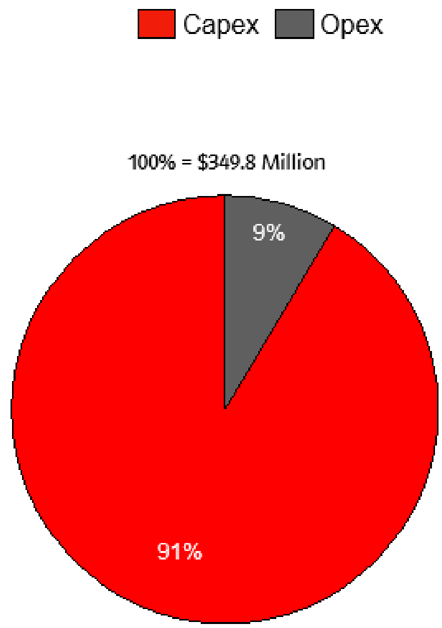
$M	Nominal Values		Net Present Values	
(Costs)				
Total Project Costs (Capital)		(320.0)		(357.1)
Total Project Costs (O&M)		(29.8)		(26.0)
Total Project Costs	**$**	**(349.8)**	**$**	**(383.1)**
Total Recurring Costs (Capital)		(43.8)		(22.3)
Total Recurring Costs (O&M)		(108.8)		(47.9)
Total Recurring Costs	**$**	**(152.6)**	**$**	**(70.2)**
Total Lifecycle Costs	**$**	**(502.4)**	**$**	**(453.3)**
Benefits				
Operational Savings		425.1		208.3
ePortal Benefit		158.0		76.7
Recovery of Non-Technical Losses		402.3		196.8
Total Lifecycle Benefits	**$**	**985.4**	**$**	**481.8**
Net Benefits vs (Costs)	**$**	**483.0**	**$**	**28.5**

Discount Rate: 6.32%

Capex vs. Opex Cost 2018 – 2022 (in $ Millions)

Capex = $320.0 Million
Opex = $29.8 Million





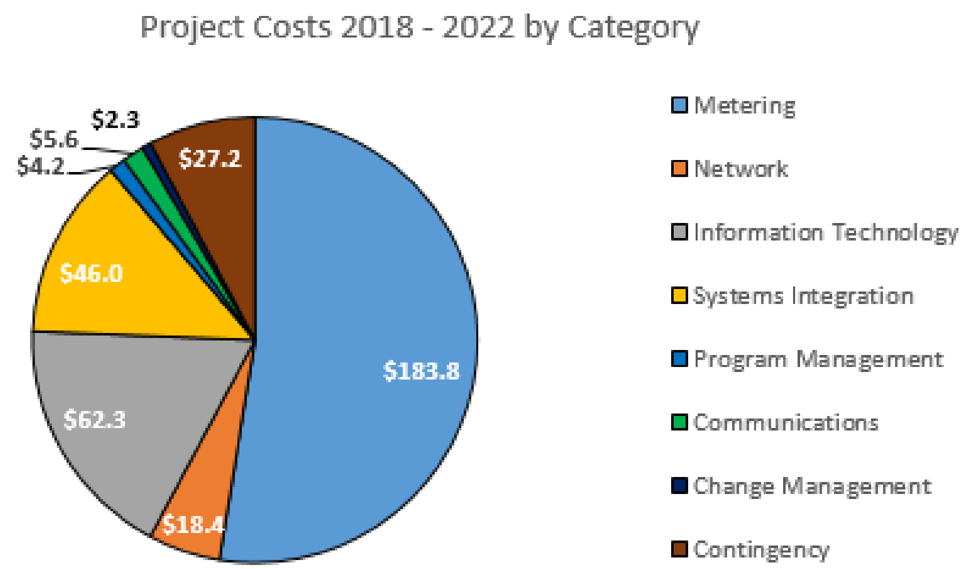
On an ongoing basis, from 2023 through 2040, the Company will have limited incremental direct AMS capital expenditure of $44 million. However, annual ongoing O&M costs will start at $5 million in 2023 and escalate to $7 million by 2040, which is, in aggregate, $109 million of O&M in the years 2023-2040, as shown below:

Total Ongoing O&M Costs ($M)

Year	O&M Costs
2023	$4.8
2024	$4.9
2025	$5.1
2026	$5.2
2027	$5.3
2028	$5.5
2029	$5.6
2030	$5.8
2031	$5.9
2032	$6.1
2033	$6.2
2034	$6.4
2035	$6.6
2036	$6.7
2037	$6.9
2038	$7.1
2039	$7.3
2040	$7.4
Total	**$108.8**

PPL companies

The costs incurred to implement this plan have been grouped into categories as shown below:



Within each of these categories, the costs were further broken down as either capital or O&M within the years over which these costs would be incurred. The costs have been presented on a nominal basis over a 5-year period. A graphical representation of these costs is shown below.

Project Costs 2018 - 2022

Category	Capital	O&M	Total
Metering	$171.1	$12.7	**$183.8**
Network	$16.8	$1.6	**$18.4**
Information Technology	$52.1	$10.2	**$62.3**
Systems Integration	$46.0	$0.0	**$46.0**
Program Management	$4.2	$0.0	**$4.2**
Communications	$1.2	$4.4	**$5.6**
Change Management	$1.4	$0.9	**$2.3**
Contingency	$27.2	$0.0	**$27.2**
Total	**$320.0**	**$29.8**	**$349.8**

Costs by Program Component

7.2.1 Meter

The most significant component of the AMS deployment is the $116 million equipment cost for the approximately 980,000 electric meters and 34,000 gas meter indices. Meter installation costs throughout the territory will vary by geography, but an average installation cost of $21 per electric meter and $22 per gas index form the basis of an overall $28 million installation cost. Another component of the meter cost is related to the repair of meter bases as part of the meter replacement process. It is estimated that approximately 1% of the meter bases encountered with the AMS deployment will require some form of repair. The costs associated with these repairs is estimated to be about $7 million. Other minor ongoing costs such as meter testing, meter failures, and customer growth are included in the total meter cost. The total estimated costs for the meter category is $224 million ($202 million capital and $22 million O&M).[33]

7.2.2 Network & Network Management

Network costs include the router and collector equipment costs which total $8 million including approximately 3,300 routers and 200 collectors. The number of routers and collectors to be deployed was determined by Landis + Gyr as part of their preliminary network design to support meter and gas index module communications for the entire Company service territory. The costs to deploy and install the network communications system will be $8 million, which includes network planning and engineering, training, and testing.

Other components of the network and network management costs include backhaul, annual component failures, and annual maintenance. The total estimated costs for the Network & Network Management category total $34M ($22 million capital and $12 million O&M).

[33] Notably, not included in this $224 million cost is the cost of ongoing purchases of spare meters to be used throughout the 20 year life of the AMS equipment. This was excluded because the spares are not expected to be purchased within the initial 5 year deployment window due to expected warranty coverage. But note that the cost of spares is included in the $502.4 million lifetime cost. Other utilities have assumed 20-year service lives for AMS meters. *See, e.g.,* Ameren Illinois Benefit-Cost Analysis in the record of the Company's 2016 base-rate cases: *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and* Necessity, Case No. 2016-00371, Attachment to AG's Response to LG&E DR 1, "Ameren Illinois Benefit-Cost Analysis.pdf" at pdf page 11 (Ameren Exhibit 2.4RO Page 7 of 52), available at https://psc.ky.gov/pscecf/2016-00371/rateintervention%40ky.gov/03312017030028/Ameren_Illinois_Benefit-Cost_analysis.pdf; Consolidated Edison AMI Business Plan provided in record of the Company's 2016 base-rate cases: Case No. 2016-00371, Attachment to AG's Response to LG&E DR 1, ConEd Study at pdf pages 44 and 61 (ConEd Study pages 40 and 57), available at https://psc.ky.gov/pscecf/2016-00371/rateintervention%40ky.gov/03312017030028/ConEd_AMI_Plan.pdf.

7.2.3 Information Technology (IT)

Information Technology costs include software, hardware, vendor support, and internal IT resources costs. The software costs to implement or enhance the head-end, MDM, customer web portal, meter operating center and meter asset management system, including the development of compatible reporting capabilities total $147 million. The associated hardware costs are $23 million. Additional labor costs associated with IT development and implementation are $25 million.

As part of the implementation of the Meter Operations Center (MOC), a new department will be created to oversee the communication infrastructure and troubleshoot meter-related issues that occur during deployment. After deployment, the MOC organization will evolve into a central management hub, responsible for proactively managing and monitoring the advanced meter and field area network performance, addressing any infrastructure problems that arise. The MOC group will, through the use of Data Analytics, investigate, identify and help implement solutions that leverage the Company's meter to cash processes to improve operation effectiveness and enhance the overall customer experience. The ongoing cost of the MOC is estimated to be $37 million ($0 capital and $37 million O&M).

The total Information Technology cost is estimated to be $232 million ($132 million capital and $100 million O&M). These costs include interfaces and integration of multiple new and existing systems. The Company is currently designing its planned system architecture, but an illustrative application architecture can be found in Appendix A-2.

7.2.4 System Integration

The system integration category captures the costs associated with external consultants to assist with coordinating and managing the implementation of the different IT packages in an optimal manner. These costs include obtaining overall architectural guidance, platform design, supporting security requirements, facilitating integration across disparate systems, comprehensive test plan development, and execution. Total System Integration costs are estimated to be $46 million ($46 million capital and $0 O&M).

7.2.5 Program Management

The Program Management category captures the costs associated with overseeing the entire program through the end of deployment. The responsibilities associated with the category include program leadership, project management, business process development, and redesign. Total Program Management costs are estimated to be $4 million ($4 million capital and $0 million O&M).

7.2.6 Customer Communications & Change Management

The Customer Communications and Change Management costs cover two categories: internal training and customer education. The training costs are estimated to be $1 million and customer education costs are estimated to be $7 million. Training costs include costs associated with both the development of training guides and modules as well as the delivery of training. The costs associated with customer education include the development of AMS plan-related materials for all stakeholders as well as the delivery of relevant education and messages through the appropriate channels as outlined in the Customer Education and Communication Plan found in Section 9 below. Total Communication and Change Management costs are estimated to be $8 million ($3 million capital and $5 million O&M).

7.2.7 Requested Waivers for Improving AMS Benefits

The Company plans to request the following waivers, approvals, and relief to implement AMS and to achieve the additional benefits of this technology.

Waiver(s) requested and included in base business case assumptions:

- 807 KAR 5:006, Section 14(3) – This regulation requires the Company to inspect the condition of meter and service connections before providing service to a new customer so that prior or fraudulent use of the facilities shall not be attributed to the new customer. The Company is requesting a waiver for only the AMS meters, which allow for remote data communication. The Company will continue to inspect the condition of legacy meters that have not yet been replaced. Annual cost to continue inspections prior to providing service to a new customer should this waiver not be granted is $3 million. A similar waiver was requested by and granted to Duke Energy Kentucky in PSC Case No. 2016-00152.

Should the Kentucky PSC grant the Company requested waivers identified below, additional annual savings would be achieved and ultimately passed on to the customer in future rate-making.

- 807 KAR 5:006, Section 26 (4)(e) and 807 KAR5:006, Section 26 (5)(a)(2) require the Company to perform inspections on electric meters every two years and gas meters every three years. Annual cost to comply with this regulation is $1.2 million. AMS provides electronic information and alarms as described in Section 4.6 and more fully shown in Appendix A-3. This electronic information includes tampering alarms. Thus, the Companies will have notice if a meter is tampered with and can follow-up with a physical inspection. Other information delivered from the meter provides the Company details of the general condition of every meter in the system on a daily basis. Consequently, the intent of the two-year and three-year inspections may be met with the electronic information provided by the AMS and thus not require periodic physical inspections.

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- 807 KAR 5:041 Section 16, and KPSC Case 2005-00276 require the Company to perform sample and periodic meter testing programs. The Company seeks to suspend its existing sample program in the deployment years and proposes to resume the sample program post-AMS deployment. Annual cost to comply with this regulation is $167,000. The estimated savings will be in the form of additional workforce capacity since this is a temporary suspension of the requirement. The contractors and employees doing this work today will be assigned other work (testing new meters) during the deployment phase and will return to testing sample meters after deployment.

- 807 KAR 5:041 Section 15 (3) requires the Company to test all removed meters. As reported quarterly to the Kentucky Public Service Commission, the Company has demonstrated that the vast majority of meters tested are operating accurately. Over the last five years, more than 99% of KU and LG&E electric meters tested have been within +/- 2%. Of the less than 1% of meters that are found to be fast or slow, 88% are slow and 12% are fast, meaning that only 0.08% of electric meters tested are fast. In addition, the Company found that since 2012 less than 1% of the meters tested at the request of a customer were found to test outside the +/- 2% tolerance.

  Warehousing and testing costs to comply with this regulation are $4.5 million. The Company suggests that this is a high cost to customers to identify roughly 0.08% of electric customers possibly impacted by a fast meter. The Company seeks to suspend its removal testing and proposes to resume it post-AMS deployment. Additionally, the Company will request permission to dispose of removed meters immediately although they have not been tested for accuracy, as these meters will not then be returned to service.

- 807 KAR 5:006 Section 19 states, "A utility shall make a test of a meter upon written request of a customer if the request is not made more frequently than once each twelve (12) months." On its face, this requirement would appear to apply only to meters still in service, not to meters already removed from service. But out of an abundance of caution, the Company will ask the Commission to grant the Company a deviation from Section 19 regarding all meters the Company removes as part of the AMS deployment. The reasons for the deviation are the same as those given above for the Company's requested deviation from 807 KAR 5:041 Section 15(3) concerning testing of meters removed from service.

7.3 Benefits and Costs Summary

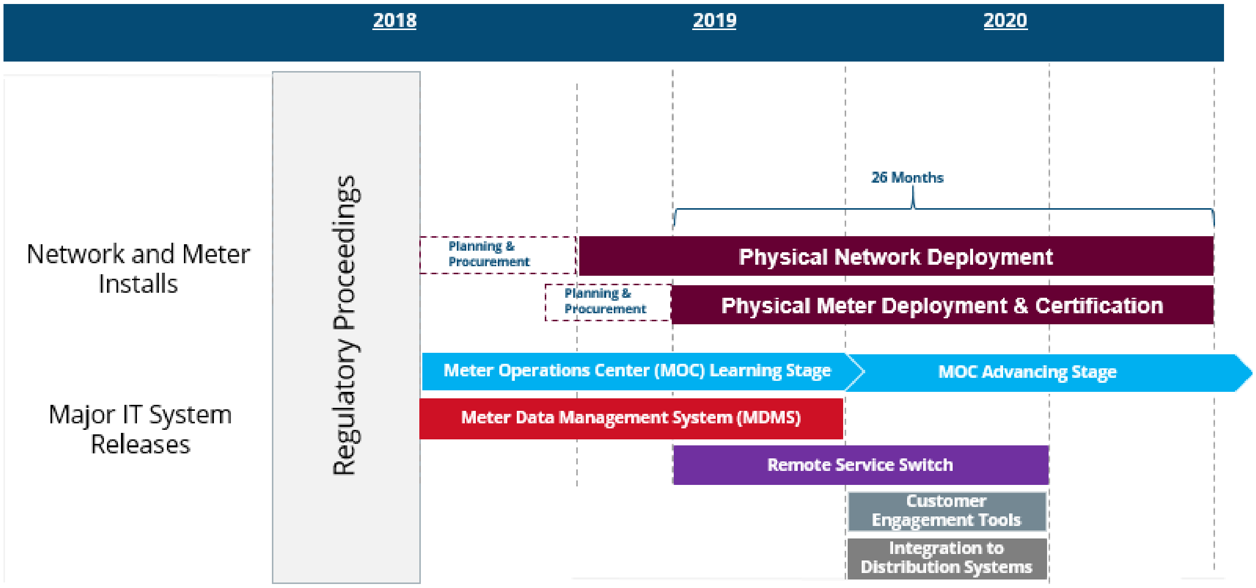
Quantitatively, the results of the Company's detailed financial modeling as part of the business case demonstrate that net benefits outweigh net costs to yield an NPV of $28 million, making AMS a prudent investment on behalf of customers.[34] The Company plans to invest $502 million ($364 million in capital and $138 million in O&M) to fund full AMS deployment and maintenance over a 20-year timeframe. Advanced meters, network infrastructure, and supporting systems make up the majority of the costs. The Company expects $985 million in benefits across the same time period. The main financial benefits revolve around meter reading cost reductions, meter services' efficiencies, reduction of non-technical energy losses, and potential energy savings resulting from customer adoption of ePortal-enabled insights. As these overall costs are expected mainly to be incurred in the first few years of the program, and benefits are expected to be over the next 20 years, financial analysis reconciles this to a comparable value in 2018 terms. The comparison of these reconciled benefits and costs yield the $28 million net present value.

8 Deployment Plan

In consideration of AMS having a direct impact on every customer, the deployment of AMS represents one of the most far-reaching initiatives the Company has ever undertaken. As such, it is vital to ensure that the transition is conducted smoothly and efficiently to minimize customer inconvenience. In preparation, over 75 people representing more than 10 different business functions have been involved in conducting significant analysis, reviewing, socializing, and planning for various facets of the AMS program. While certain detailed activities continue to maintain internal awareness and momentum, the overall organization is fully prepared to mobilize to make this vision a reality.

The AMS program will comprise numerous systems, components, facility modifications, and many meter installations which must be carefully coordinated and sequenced. The high-level plan includes a full implementation over three years beginning in mid-2018 as shown below:

[34] Please note that these values were calculated prior to the recent revision in the federal corporate income tax rate. The Companies are currently working to revise these calculations to account for the new tax rate and will file them in this proceeding as soon as reasonably possible, and no later than January 31, 2018. Preliminary calculations indicate the effect of the new tax rate will be to slightly increase the proposed deployment's net benefits on a net present value basis.

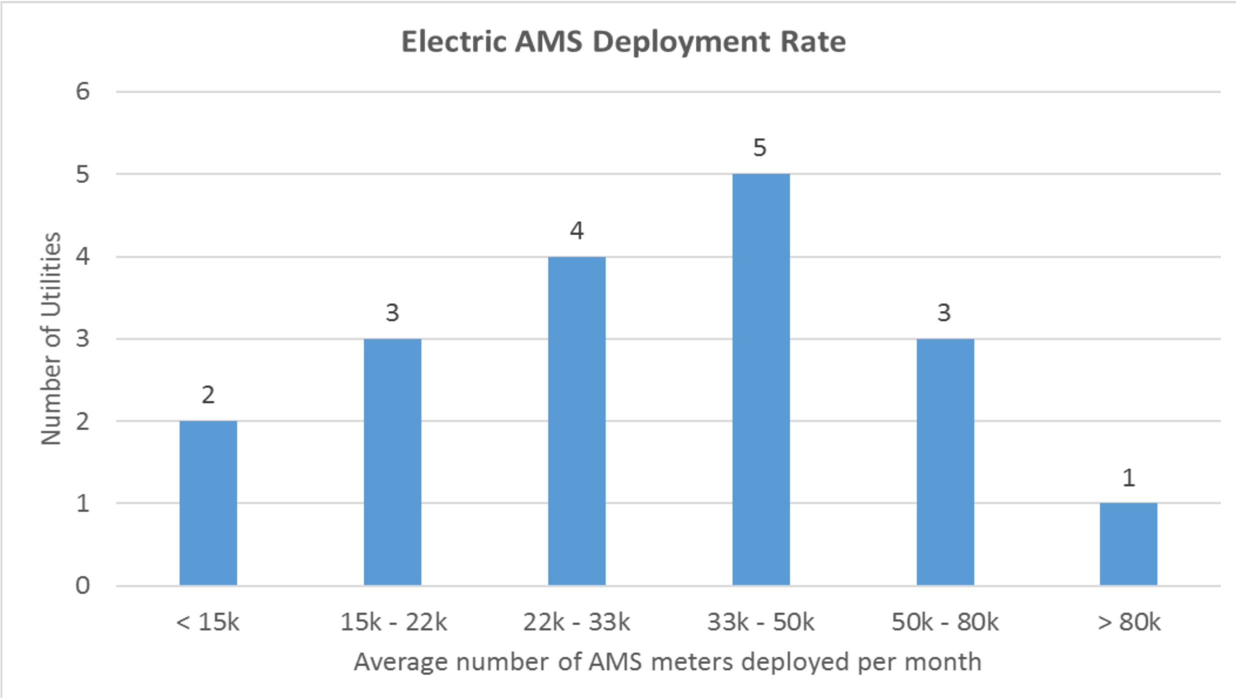


8.1 Electric Meter and Gas Index Installations

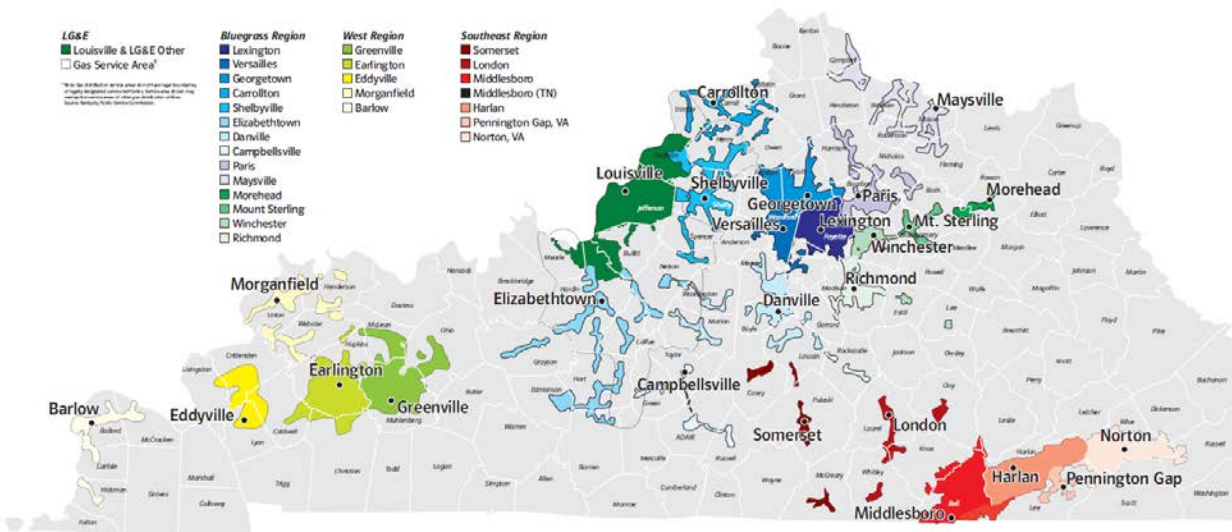
Electric meter and gas index deployment in the Company's service territory is planned to start in early 2019 after regulatory approval is received. Each meter, upon installation, will begin to communicate through the Company network providing initial connectivity data to the existing AMS head end. Soon after their AMS meter is installed, customers will have access to all capabilities currently available only to the AMS Customer Service Offering participants. This functionality includes access to their daily incremental meter reads through ePortal. Full Company and customer benefits will not be realized until remaining AMS systems are brought online later in the program, which is expected to be in mid-2021.

Deployments will initially commence in the Louisville area due to the population density and prevalence of existing AMS Customer Service Offering infrastructure. Crews will exchange meters in accordance with defined processes that include: capturing the final meter reading from the existing meter, removal of the existing meter, performing any necessary meter base repair, capturing new meter characteristics for the Meter Asset Management system, installing a new meter, and backoffice validation of the removed meter's accuracy.

The Company plans to average roughly 38,000 electric meter exchanges per month. Through research conducted as part of the AMS planning effort, the Company has found that other investor-owned Utilities (IOUs) have typically deployed meters at an average rate of approximately 37,000 metering sites per month, and the Company plan is within the prevailing range of 33,000 to 50,000 electric meters per month as shown in the figure below. This estimate also includes deployment of routers and collectors to enable communications between meters and back-office systems.



Using this rough guideline, meter and module exchanges are estimated for the following regions per the chart as shown in the following diagrams:



	2019			2020				2021		
Company	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Total
LG&E Electric Meters	36,507	59,715	64,331	57,405	61,098	64,790	58,328	11,442		413,615
LG&E Gas Modules	14,624	49,560	48,748	57,599	72,105	70,374	21,038			334,048
KU Electric Meters	13,467	60,385	65,149	60,803	98,759	110,067	100,705	22,265		531,600
ODP Electric Meters								18,038	12,513	30,551
Total Installed	64,597	169,661	178,228	175,806	231,962	245,231	180,072	51,744	12,513	1,309,814

Percent Complete (cumulative)

	2019									2020												2021				
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
LGE Electric Meters	2%	5%	9%	14%	19%	24%	29%	34%	39%	44%	48%	53%	57%	62%	68%	73%	78%	83%	88%	93%	97%	100%	100%	100%	100%	100%
LGE Gas Modules	0%	1%	4%	9%	14%	19%	24%	29%	34%	39%	44%	51%	58%	65%	73%	80%	87%	94%	98%	100%	100%	100%	100%	100%	100%	100%
KU Meters	0%	0%	3%	6%	10%	14%	18%	22%	26%	30%	34%	38%	43%	49%	56%	63%	70%	77%	84%	90%	96%	100%	100%	100%	100%	100%
ODP Meters	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	16%	36%	59%	82%	100%

8.2 Major IT System Releases

Over the last year, the Company has moved forward on several IT initiatives including the upgrade of its AHE and the implementation of its meter asset management system (MAM). As part of this AMS implementation project the Company will configure and deploy several new systems and enhance existing systems to accommodate AMS technology. These increased capabilities will be pursued through several staggered releases. Each release is designed to provide incremental functionality that will allow the Company to systematically increase operational efficiencies or effectively address customer experience considerations.

Descriptions of each of these releases are as follows:

- Release 1 – In Release One, the Company will (a) implement or enhance the tools and organizations necessary to enable efficient processes to deploy, inventory , and optimize meter communications and (b) provide the core remote meter reading capabilities to allow manual periodic meter reads to cease and new AMS registered read data to be utilized for customer billing. In addition, the Company will develop the meter data management system (MDMS) to validate meter read data and process the data to ensure billable quantities. The following activities are included in Release One:
    - Enhancement of the MAM to accommodate AMS characteristics of the AMS meters as they are deployed.
    - Stand up of the metering operations center (MOC) organization to monitor communications channels between meters and the AMS head end.
    - Development of the interfaces between the Company and its deployment vendor to enable and ensure meter exchanges are accurately reported to the Company.
    - Meter Maintenance and service order updates between SAP and MDMS ensuring customer and meter data is in sync between the two systems.
    - Stand up of the processes by which meter reads are received and processed by the MDMS.
    - Develop the usage and billing processes ranging from usage requests to validation, customer move in or move out, and read estimation.
    - Develop exception management processes.
    - Enable additional meter pinging capabilities in the CIS and AHE that will allow CSRs and operations staff to dynamically confirm power status in real-time.

- Release 2 – In Release Two, remote service switching will be enabled allowing CSRs and Company operations staff to energize a previously disconnected premise per predetermined schedule or ad-hoc requirement. Remote service switching capabilities will be configured and enabled for meter services functions.

- Release 3 – In Release Three, the Company will (a) enhance ePortal and My Account functionality to provide customers with rate information allowing them to analyze how different rate options fit their lifestyle and (b) integrate to Distribution systems for improved outage management.

8.3 Project Management Protocol

Given the size and cost associated with the AMS program, it is vital to ensure that the implementation is managed through an established set of procedures and processes. This methodology will be strictly adhered to with this program much as it is for other large infrastructure implementations pursued through other parts of the Company. The Company's robust program management governance structure adds a number of valuable organizational tools and protocols to ensure program alignment and compliance with project expectations. The Company has the appropriate expertise, governance, and partners necessary to successfully deliver a full AMS deployment, as it has done with numerous large capital projects in the past.

9 Customer Education and Communications Plan

9.1 Introduction

Advanced Meter Service technologies give customers new data, tools, and control over their energy consumption for a holistic set of benefits as described. Communication, education, and support through the deployment will be key in addressing customer concerns and demonstrating the benefits of AMS. A successful education and communications plan will drive high levels of customer engagement and help customers achieve maximum benefits.

Various internal studies of third-party customer satisfaction surveys have shown a connection between strong, proactive customer communications and positive customer experiences with AMS programs. Thus, the Company will develop a multi-faceted customer education and communications plan to educate customers, as well as community stakeholders, throughout the duration of the project and after customers receive their meters to encourage participation and support of future programs.

This will include providing a robust offering of information on a variety of topics, to include how the program works; the meter installation process; the new tools and features, such as the ePortal-functionality, available through AMS; and new ways to help manage their energy use and modify their services. The Companies' customer-education efforts will also make customers aware of their ability to opt-out of the AMS deployment, noting that the ability to opt out is subject to operational and safety restrictions.

The Company serves a diverse population of customers that have different needs and require different communications and education approaches. To reach all customers and community stakeholders, the Company plans to use a wide array of communication vehicles, such as:

- Print and digital advertising
- Automated calls
- Community outreach and events
- Customer newsletters and bill inserts
- Direct mail
- Email
- Informational updates through the ePortal
- Online videos and banners

- Media relations
- Social media

An example display of information available on the ePortal that is used in customer outreach efforts for the AMS Customer Service Offering can be seen below. Additional communication materials can be found in the Appendix A-4.

9.2 Implementation Plan

The Company anticipates that customer communications and education will vary at different times throughout the AMS deployment. Diverse customer audiences and community stakeholders with varying interests make creating dynamic outreach, engagement, and education programs essential. The Company will develop a three-stage, comprehensive approach using a multi-channel, multimedia campaign to inform and educate customers and community stakeholders, creating two-way conversations about AMS technology. This well-structured plan is designed to increase acceptance, ease implementation, and allow customers to make informed decisions. The three stages of the communication and education campaign are shown below:

Stage 1 - Deployment: During the meter deployment stage to the Company will initiate a fact-based Advanced Meter Systems education and awareness campaign that informs customers and community stakeholders about the purpose of the program and the benefits associated with AMS, including the customer's increased access to individual usage data.

Stage 2 – Customer engagement: Once meters have been deployed, the next stage will further educate customers about the new features and tools available through AMS. As with similar Company initiatives, during this stage the Company will survey customers to determine their level of engagement, energy literacy, and understanding of AMS. The survey results will assist the Company in determining the best approach to engage customer, and encourage them to participate, and provide them with information on what they can do to fully take advantage of these offerings. This includes participation in other Company programs and innovative rate structures that can help incentivizes customers to better manage their individual energy usage and costs based on their unique situations. The increased knowledge of opportunities, coupled with customer engagement, aims to increase customer satisfaction by giving them control, options, and information to make energy choices that best fit their individual needs.

Stage 3 – Customized communications: As with other Company initiatives and programs**,** once AMS has been fully implemented, the Company will continue a longer-term effort, which will adjust in response to customers' needs, operational programs, and rate plans that are enabled by the AMS implementation. Over the years the Company has developed various avenues with which to communicate with its customers. Recently, customers were provided a visual walk through of the Company's newly redesigned bill. This visual walk through included a bill insert that identified and explained the features of the redesigned bill. Below is an excerpt from this informative communication.

For AMS, the Company will be able to create similar educational and informative communications for its customers, to provide them with the information they need to capitalize on the new AMS technology.

9.2.1 Customer Access

To fully enjoy all benefits that AMS provides, customers will need a means to access their data. Today there are a number of federal and state programs that can provide customers with important information on acquiring access to web based information. In addition, the Company can leverage its current communication expertise to direct customers to various access options, including the use of bill inserts that can direct customers to facilities that provide free access to web based information, such as Company business offices and local libraries.

9.3 Internal Customer Service Training

As part of the AMS implementation, the Company plans to provide training to its CSRs and back office personnel that will enable them with the skills and knowledge to assist customers with details of their specific usage patterns, optional rate plans that may be more beneficial based on the customer's usage, information on the meter condition, and billing inquiries.

9.4 Flexibility and Adjustment

The components and overall strategy are designed to be dynamic and flexible in nature to meet customers' and community stakeholders' needs. The Company will address questions and any concerns, and will closely monitor deployment progress and customer feedback to revise the plan as needed.

9.5 Residential Time-of-Day Rates

Different usage trends, economic constraints, familiarity with the technology, and various other circumstances make every customer unique, leading to a wide variety of individual customers' interests. To provide customers with options that fit their unique needs, the Company introduced two new Residential Time-of-Day (RTOD) rate structures along with the AMS Customer Service Offering currently available.

Through time-of-day rates, the Company provides optional rate structures that more accurately reflect the actual cost of providing service to customers. Through these price signals, rates are lower at times when baseload generation is a larger part of the mix and higher at peak times when fast-ramping, expensive generation is required to meet customer demand. These programs are about customer choice: customers can save money by shifting their energy usage to off-peak hours or they can choose to incur higher costs and use power when it is most expensive. By enabling flexibility, these rate plans have received positive responses from customers, but they have been somewhat limited to customers who already have an understanding of their energy usage or know that they are natural, or minimal effort, beneficiaries based upon their current lifestyle (e.g., customers who leave their home at 7 AM for work and return after 6 PM).

AMS implementation, with ePortal-support and proper customer education, has the potential to greatly increase enrollment in time-of-day rates. Customers who currently lack the information needed to compare available rate plans will have access to interval data to make more informed decisions. At a minimum, this data will help customers think through the potentially cost-saving effects of enrolling in these time-of-day rates and other customer programs with no other necessary behavioral changes. Customers will also have the option to explore alternate rates with the help of Company representatives and will be able to consider what additional savings may be possible if they choose to adjust their consumption patterns. Increased participation in time-of-day rates gives customers a clear path toward lowering their energy bills and will mutually benefit the utility by relieving stress on needed supply during peak generation hours.

10 AMS Analytics

As outlined above, AMS technologies provide many direct capabilities to increase the efficiency of previously manual business processes. Data analytics are crucial to unlocking many of these capabilities and support new processes that will lead to positive customer benefits. For instance, the benefit to reduce non-technical losses is highly dependent on analytics. Advanced meters use embedded logic to assess how power is flowing through the meter and can make a determination if the meter has been tampered with. If the meter detects tampering, it can send a notification to central operators. Field services personnel can then be dispatched to inspect, confirm, and mitigate as warranted. This reduces non-technical losses, with these savings being passed onto customers. Other benefits dependent on analytics include Outage Detection and Remediation, Voltage Violation Detection, and “OK-on-Arrival” reduction.

Data analytics is an area of innovation in the utilities industry, a trend that the Company is confident will continue. By deployment of foundational AMS technologies, the Company will be well-positioned to adopt new analytical techniques as they emerge within the industry.

11 Cyber-security

In today’s digital world, cyber-security threats are sophisticated and continue to evolve at an accelerating pace. The Company understands that it must keep pace to stay in front of those threats to sustain reliable energy delivery and protect sensitive customer data. A thorough, but flexible cyber security program in the deployment of AMS is planned. This cyber-security program is crucial to monitoring and protecting the decentralized elements of the advanced meter systems.

The Company currently has standards, frameworks, and guidelines addressing safe and reliable methods to gather, store, process, and communicate electronic information in support of this goal. The Company has applied this rigorous methodology to existing confidential customer data with great success. As new cyber-infrastructure is deployed to collect customer consumption data, similar scrutiny will be applied to ensure its protection. Cyber security strategies are shaped by adherence to all federal and state information protection standards, coordination with industry thought leaders, and various forums established to share best practices and key learnings to thwart and respond to cyber-attacks. A non-exhaustive list of approaches includes;

- Systematic identification of vulnerabilities through scans of cyber infrastructure;
- Vulnerability-specific, risk-based security plans targeting, identifying, protecting, detecting, responding and recovering from and to security breaches;
- Asset and configuration inventory management to identify exceptions;
- Password management including length and complexity requirements and monitoring at key network access points;
- Data analytics to identify behavior abnormalities in efforts to either proactively prevent cyber-attacks or investigate breaches; and
- Continuous review and improvement of the security program to match the evolution of security threats.

These activities will be used to help evaluate processes and entry points (both cyber and physical) on an ongoing basis and ensure that the Company protects emerging AMS data to the best of its ability.

12 Privacy

Increased granularity and volumes of customer data are the basis for many AMS benefits. Customers see this information as an insight into their private lives; therefore, it needs to be treated with respect and care. The Company values its positive relationship with its customers and believes that misuse or any kind of disclosure (intentional or unintentional) represents an unacceptable breach. An existing privacy policy shown below has been in place for several years and will apply to AMS data:

We will make every effort to protect and preserve customer account information and will not share specific information about your account with third parties, without written authorization or unless we are required to do so by a court order, subpoena or other compulsory process, or by operation of law.

Customer account information may be used by us in the following representative ways:

- *To verify the existence of a customer's energy service;*
- *To communicate with a customer and handle customer requests;*
- *To compile information about how our web site is reached and used;*
- *To compile research that does not identify the customer as an individual, group or entity other than age group and gender;*
- *To contact our customers about other products or services offered by our alliance partners; and*
- *To collect debts owed by a customer.*

Further, the Company will require any and all contractors involved with AMS deployment to follow the Company's privacy policy. Ensuring customer awareness and mitigation of any concerns they have regarding the protection of their consumption data will be a key theme of the Customer Education and Communication Plan.

13 Summary

The Company held several collaborative discussions with community stakeholders. Established under the agreement the Company reached with most of the parties who participated in the 2016 rate case review, these five collaborative sessions gave stakeholders the opportunity to express their concerns and questions around AMS implementation. Participants included the Office of the Attorney General (OAG), low income advocates, Kentucky School Boards Association (KSBA), the Sierra Club, and municipalites within the Company's service territory. Topics discussed during these collaborative session included

- The cost and benefits of the AMS program as it was originally filed in 2016 compared to the current, refined business case;
- Data Privacy and Data Access;
- Data Empowerment;
- Customer Education;
- Optional Opt-Out provision;

- Remote Service Switch Capabilities; and
- Possible New Services.

In summary, the Company has rigorously worked to identify benefits and costs associated with full AMS deployment. Based on the results of this analysis, the Company is confident that full AMS deployment will lower operational costs while increasing customer satisfaction. Additionally, AMS will lay the foundation for future advanced capabilities that can be explored. The Company's position is supported by internal conversations and experience gained through pilot programs, and industry research. Additional information is available in the appendices.

Appendix A-1

Advanced Meter Service Participant Study

Bellomy Research

LG&E KU
PPL companies

Advanced Meter Service Participant Study

06.15.2016

PREPARED BY
bellomy research

Agenda

Background and Objectives

Background

Advanced Meter Service (AMS) is a voluntary service offered by LG&E/KU that uses advanced meters to record energy usage data in 15, 30 or 60 minute increments. Customers who are enrolled can track detailed information about their electricity usage via an online portal (MyMeter dashboard), helping them better understand and control energy usage in their home. Enrollment was first offered during the summer of 2015, followed by installation of meters beginning in November 2015.

In May 2016, LG&E/KU partnered with Bellomy Research to conduct a study to evaluate perceptions among Advanced Meter Service (AMS) participants.

Objectives

The overall objective is to understand customer perceptions of the Advanced Meter Service (AMS) offering, as well as to gauge interest in additional MyMeter dashboard features. Specific objectives include understanding:

- Overall satisfaction with the AMS offering
- Satisfaction with the MyMeter dashboard
- Interest in additional MyMeter dashboard features
- Changes in behavior due to participation

Methodology

This study was conducted using an online survey. Bellomy Research provided the survey link to customers via an email invitation. The link to the online survey was open to customers 24/7 for 10 days. No reminders were sent, due to high initial response rates.

LG&E/KU provided a sample file containing a list of customers currently participating in the Advanced Meter Service (AMS). The file contained approximately 2,100 customers, which all had an email address on record. After sample cleaning and removal of duplicate email addresses, the survey invitation was sent to approximately 2,000 customers.

Response Rate Summary:

	Emails Delivered	Survey Completes	Response Rate
Total	1,971	370	18.8%
LG&E	1,010	179	17.7%
KU	961	191	19.9%

Methodology

Data collection for this research was conducted during the second and third weeks of May 2016. The survey was approximately 5 minutes in length.

A breakdown of completed surveys by Utility and Customer Type is below:

	Total	LG&E	KU
Total	370	179	191
Residential	364	178	186
Commercial	6	1	5

Statistical testing was conducted at the 95% confidence level, and significant differences are noted.

Executive Summary

Most customers currently participating are satisfied with the Advanced Meter Service (77%) and MyMeter Dashboard (75%).

- Higher satisfaction among KU customers is the result of LG&E customers being slightly more "neutral" towards the service, although both rate the Dashboard similarly.

AMS participants are very engaged when it comes to saving energy. Most have taken additional steps since joining the program by doing things such as upgrading to LED bulbs, programming thermostat settings and enrolling in utility energy efficiency programs.

Although satisfaction with the Dashboard is high, some opportunities exist:

- Customers who access the MyMeter Dashboard more frequently tend to be happier with the service. Continue to encourage customers to access the Dashboard.

- There is an opportunity for continuous communication and education among participants since some who have never accessed the MyMeter Dashboard (16%) said they did not know about it or how to access it.

- Ease of accessing the MyMeter Dashboard was the lowest rated attribute, suggesting an area for improvement. Possibly explore providing a mobile app, which was especially desirable among younger customers.

- Few customers are using "energy markers" or schedule MyMeter notifications.

Participants were asked to provide feedback on having an option to review energy usage in terms of dollars and not just kWh. Most (86%) were interested in this new MyMeter Dashboard feature.

- The highest interest was among customers ages 35 to 44 years old, which tend to have higher usage (larger households).

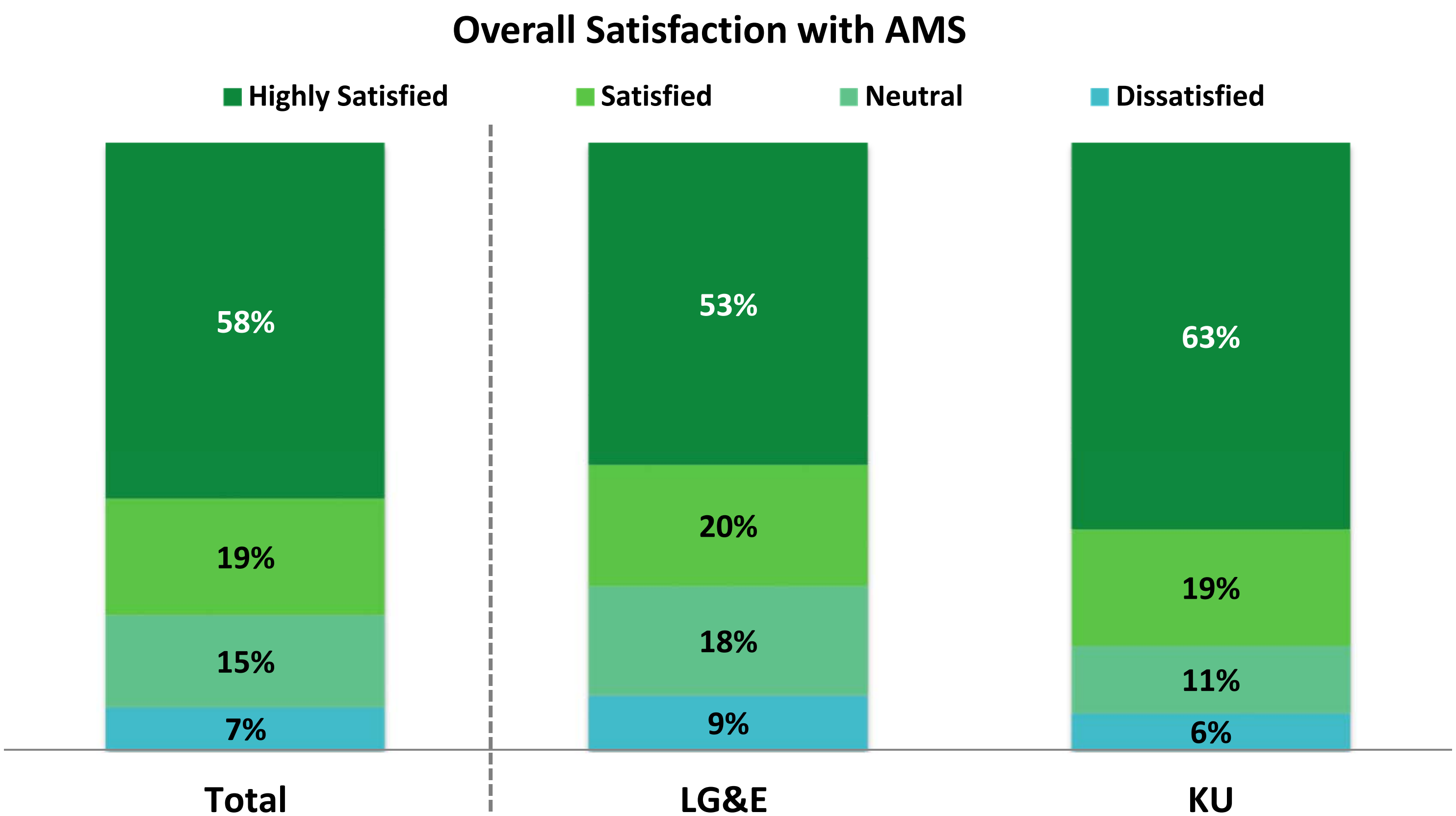
- The verbiage provided in the survey did a good job of clearly explaining that the dollar usage provided on MyMeter is not going to reflect the actual full bill amount.

- Some customers did raise concerns about dollars being a variable measure since energy prices can change, while kWh is constant. Further explanation might be required on how to compare dollar usage over time. In addition, it should be emphasized that customers have the option of looking at either.

Satisfaction with Advanced Meter Service

Overall Satisfaction

Nearly 3 out of 5 participants surveyed were *Highly Satisfied* with LG&E/KU's Advanced Meter Service (AMS) offering, although ratings were directionally higher among KU customers. LG&E customers were somewhat more likely than KU customers to give a *Neutral* rating.



	Total	LG&E	KU
Mean	8.4	8.3	8.6

Q1. Overall, how satisfied are you with the Advanced Meter Service?

Overall Satisfaction

Satisfied customers found the information provided by AMS to be very useful and felt the graphics on the MyMeter Dashboard were interesting. Customers who were *Neutral* or *Dissatisfied* with AMS expressed concerns about the timeliness of the data and difficulty accessing the MyMeter Dashboard.

Highly Satisfied or Satisfied (rating 8-10) (n=257)

It's very beneficial to see what time of day your energy spikes to know what is causing the extra watts.
Overall Sat=10

I enjoy seeing where I rank among other home owners in my area.
Overall Sat=10

I thought it was very informative. I really liked the graphics.
Overall Sat=9

It displays interesting information. However, I would need someone to discuss the results with me to know how to lower my bill.
Overall Sat=8

Great advancement in tracking energy usage
Overall Sat=10

Neutral or Dissatisfied (rating 1-7) (n=73)

I would like to see real time usage.
Overall Sat=6

Works okay but could use a fair bit of tuning and polish.
Overall Sat=7

I like having the meter, but it is difficult to access data and download it to analyze.
Overall Sat=7

It's difficult to look at the results, having to log onto the KU account, then find the meter link seems complicated. Not having the information linked to an app is difficult, as well and the 2 day delay in information does not allow a good reference to energy usage in the house.
Overall Sat=7

It is too difficult to access the data.
Overall Sat=1

Q1a. Why did you give this rating?

Overall Satisfaction

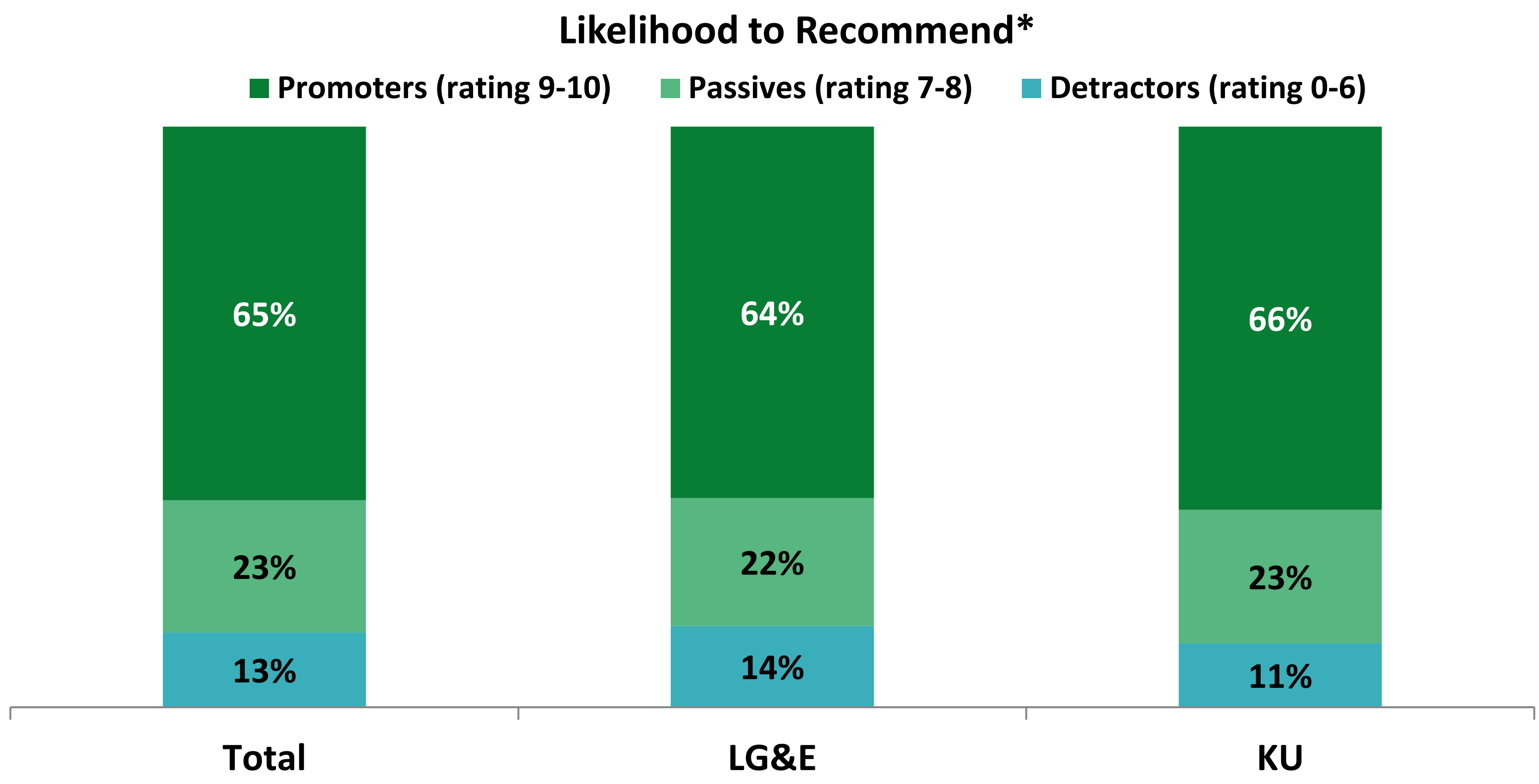
Satisfied participants are more likely than *Neutral* or *Dissatisfied* to access MyMeter and use the information they obtain from the site to make changes to save energy. They are also more likely to be ages 55 to 64 and/or have a college degree, likely having the technical savvy to take full advantage of AMS.

	Highly Satisfied or Satisfied (rating 8-10)	Neutral or Dissatisfied (rating 1-7)
Base	***257***	***73***
Frequency of MyMeter Access		
Weekly	21% +	12%
Never	7% -	18%
Steps Taken to Save Energy*		
Upgraded to LED Bulbs	63% +	40%
Program Thermostat Temperature Settings	48% +	30%
None	16% -	35%
Age		
55-64	21% +	10%
Education		
Some college/technical school	14%	23%
College graduate	42%	33%

*Among customers who have accessed the MyMeter Dashboard (Highly Satisfied or Satisfied n=240, Neutral or Dissatisfied n=60)
Note: +/- indicates significant difference between Highly Satisfied or Satisfied and Neutral or Dissatisfied at 95% confidence level

Net Promoter Score – Likelihood to Recommend

Nearly two-thirds of participants surveyed are *Promoters* of the Advanced Meter Service and are likely to recommend the program to others. With significantly fewer *Detractors,* the Advanced Meter Service yields a strong Net Promotor Score (NPS) of 52.



NPS	52	50	54

Q11. How likely are you to recommend the Advanced Meter Service to friends or family?
*Among customers who have accessed the MyMeter Dashboard (n=310)

Net Promoter Score – Likelihood to Recommend

Detractors (rating 0-6) were asked to explain why they gave their rating and many mentioned not understanding AMS or not finding the information provided by the current offering to be valuable. This suggests an opportunity to educate current participants about AMS and how best to use the information from MyMeter.

Detractors (rating 0-6)
(n=39)

The current information you provide is not very good.
Likely to Recommend rating = 5

Don't understand it!!
Likely to Recommend rating = 2

Most people I know are not that concerned and it's one more computer project to figure out.
Likely to Recommend rating = 5

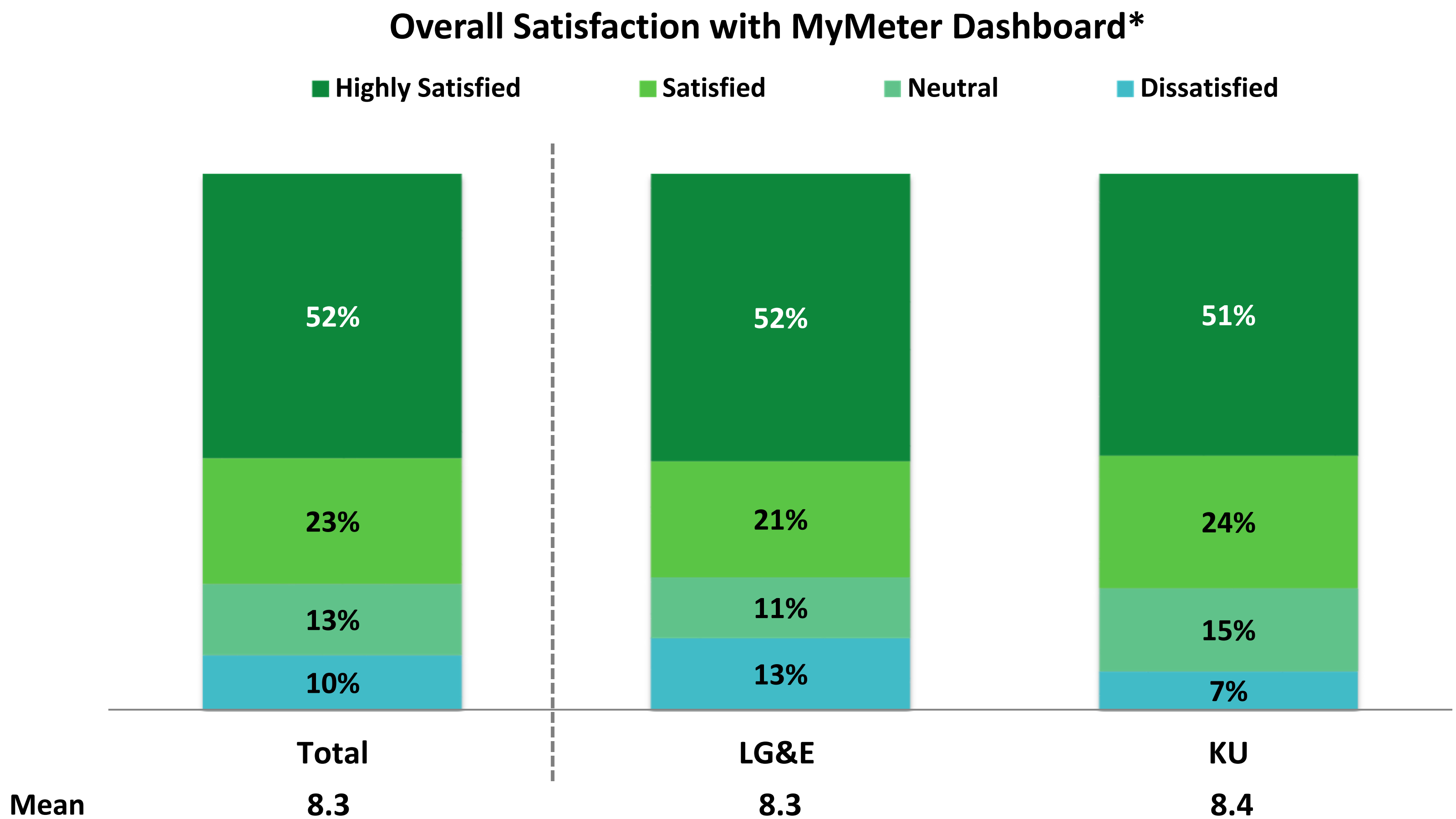
Haven't found the item beneficial. Actually, I wish I had my bills from my old school meter back. They were more appropriate. I called and spoke with LG&E about it, they said the bills changed so much because most bills are estimated.
Likely to Recommend rating = 5

It's hard to recommend something I don't thoroughly understand.
Likely to Recommend rating = 5

Q11a. Why did you give this rating?

MyMeter Dashboard

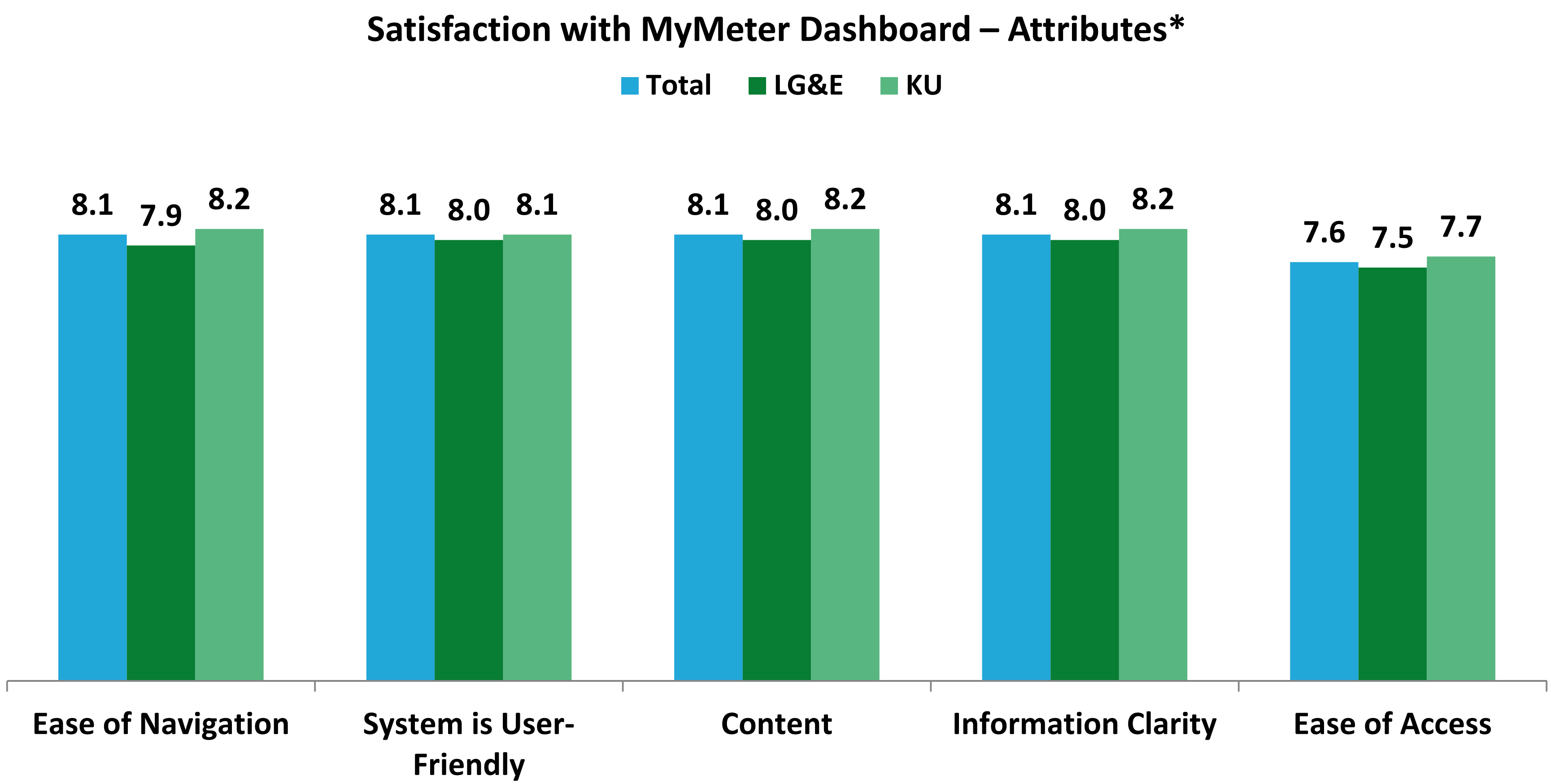
LG&E and KU customers rated their satisfaction with the MyMeter Dashboard more similarly than their Overall Satisfaction with AMS, with just over half of customers for both utilities *Highly Satisfied*. However, slightly more LG&E customers stated they were *Dissatisfied* with the dashboard.



Q3. How would you rate your overall satisfaction with the MyMeter dashboard?
*Among customers who have accessed the MyMeter Dashboard (n=310)

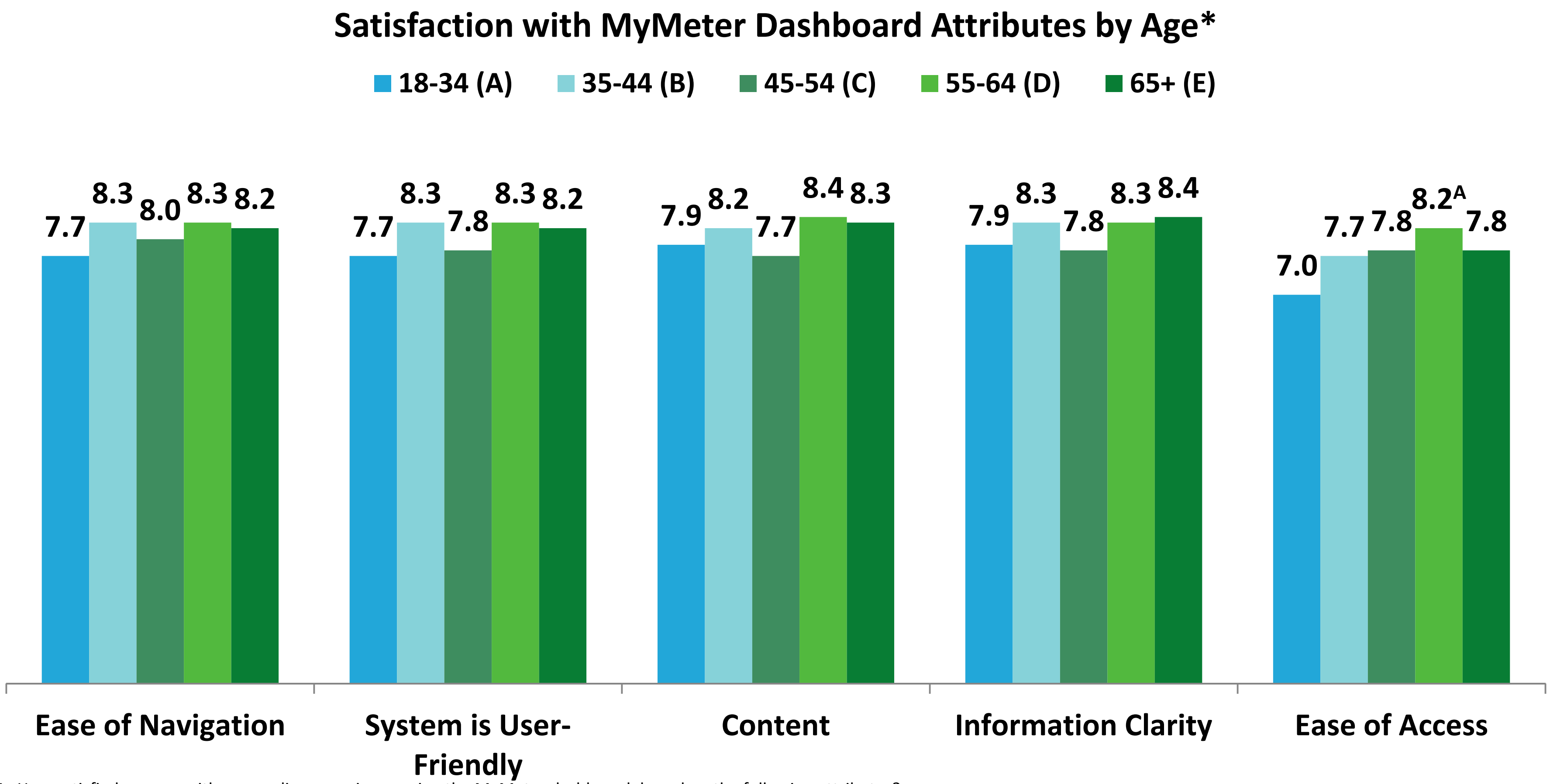
MyMeter Dashboard Attributes

Ratings were similar for LG&E and KU customers across all attributes. Ease of Access was rated lower than the other attributes, suggesting an opportunity to make the dashboard easier to access (possibly via a mobile app).



Q4. How satisfied are you with your online experience using the MyMeter dashboard, based on the following attributes?
*Among customers who have accessed the MyMeter Dashboard (n=310)

Younger customers rated satisfaction with Ease of Access lower than all other age groups, further illustrating the opportunity to meet Millennial customer's expectations for quick and easy access to information most commonly obtained via a mobile device.

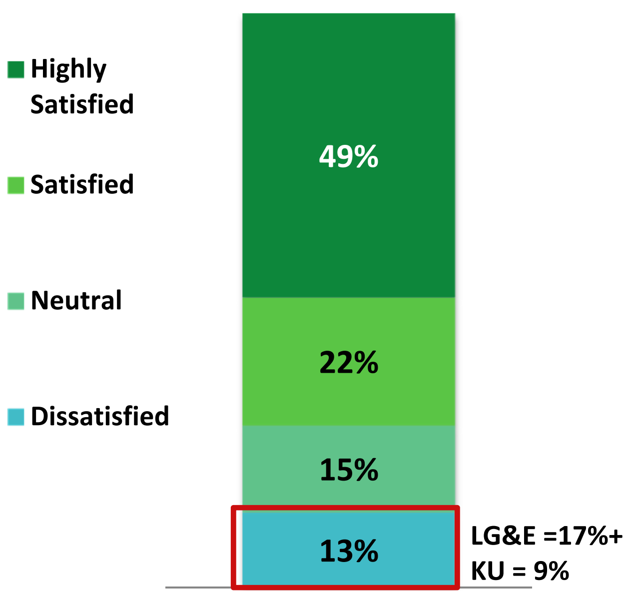


Q4. How satisfied are you with your online experience using the MyMeter dashboard, based on the following attributes?
C2. In what range does your age fall?
*Among customers who have accessed the MyMeter Dashboard (n=310)

MyMeter Dashboard – Ease of Navigation

LG&E customers were more likely to be *Dissatisfied* than KU customers with ease of navigating the MyMeter Dashboard. Many *Dissatisfied* customers mentioned difficulty navigating through the LG&E/KU website to find where to access MyMeter, while others found it difficult to navigate through the various reports available on MyMeter. Lack of mobile access was also mentioned.

39 out of 310 participants were dissatisfied with "Ease of Navigation"



Ease of Navigation

I have to click through so many different links on the LG&E site to get to it.
LG&E, Ease of Navigation rating = 5

It takes several pages and clicks to actually get to the dashboard and again, no mobile.
LG&E, Ease of Navigation rating = 3

It is very difficult to access. It is buried in several layers of menus. You do not have direct access to it from the "app."
LG&E, Ease of Navigation rating = 4

It is difficult to navigate and utilize the different views of the data.
KU, Ease of Navigation rating = 5

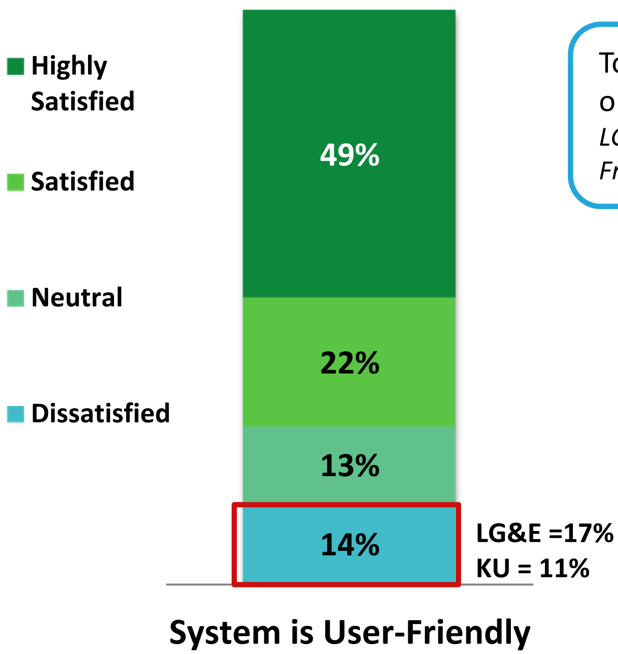
Interface is not intuitive.
LG&E, Ease of Navigation rating = 4

Q4a. Why did you rate the ease of navigating the MyMeter dashboard a **[Insert rating]**?
Note: +/- indicates significant difference between LG&E and KU at 95% confidence level

MyMeter Dashboard – System is User-Friendly

Among the 14% of customers who were *Dissatisfied* with MyMeter's user-friendliness, many mentioned having issues understanding how to use the tool and not being able to easily find instructions. Making tutorials and other instructions more readily available to participants could improve their experience with MyMeter.

43 out of 310 participants were dissatisfied with "System is User-Friendly"



Too much going on in one page.
LG&E, System is User-Friendly rating = 5

Navigation needs to be more intuitive. Have a user experience professional do it, not a programmer.
KU, System is User-Friendly rating = 3

There aren't any instructions so you have to figure it out on your own.
KU, System is User-Friendly rating = 2

Not clear how to select the various variables on the dashboard.
LG&E, System is User-Friendly rating = 5

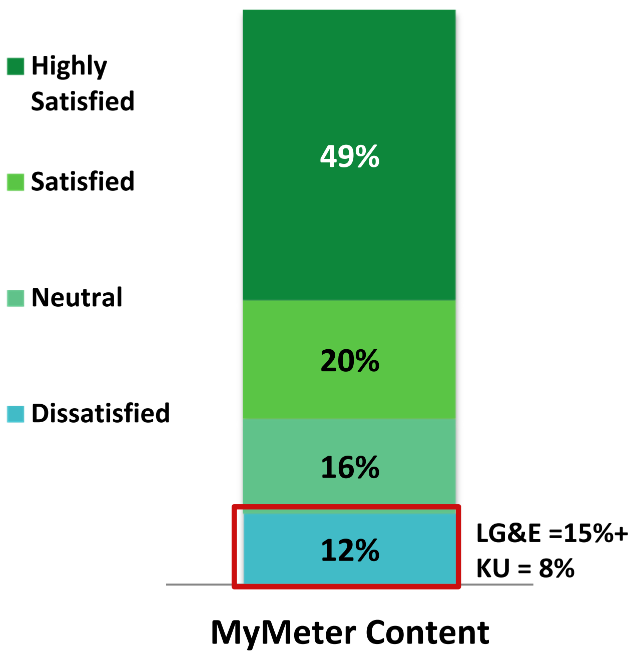
The interface seems more complicated than necessary.
KU, System is User-Friendly rating = 5

Q4b. Why did you rate the user-friendliness of the MyMeter dashboard a **[Insert rating]**?

MyMeter Dashboard – Content

LG&E customers were more likely to be *Dissatisfied* than KU customers with the content of the MyMeter Dashboard. *Dissatisfied* customers commented that the tool did not provide enough information or that the information that was available was not actionable to them. Others wanted more options to customize the reports and graphics available on MyMeter.

36 out of 310 participants were dissatisfied with "MyMeter Content"



It doesn't have enough "meat." Needs more info.
LG&E, Content rating = 3

Not sure what it displays, or might display.
KU, Content rating = 5

Lacks customizable graphs of any value.
KU, Content rating = 3

The information presented does little to inform me on where and how I can reduce my usage.
LG&E, Content rating = 5

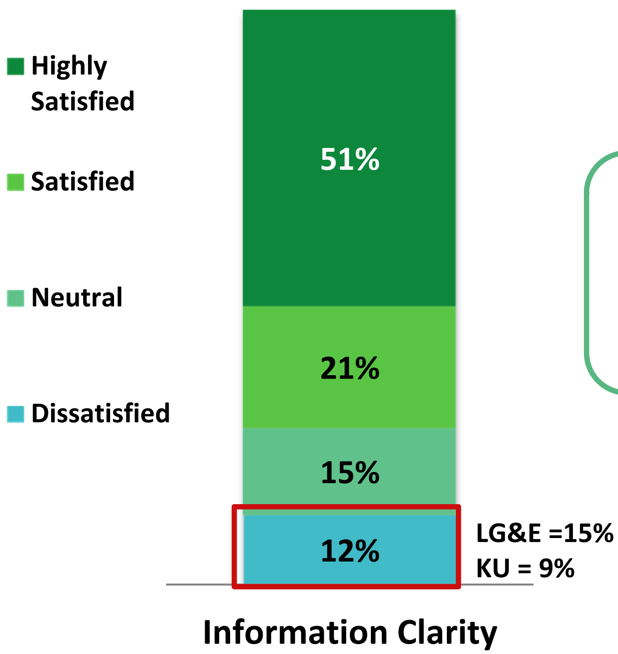
Same reason. Doesn't tell me where I am using too much energy.
LG&E, Content rating = 5

Q4d. Why did you rate the MyMeter content a **[Insert rating]**?
Note: +/- indicates significant difference between LG&E and KU at 95% confidence level

MyMeter Dashboard – Information Clarity

The majority of customers who were *Dissatisfied* with clarity of the information available on MyMeter expressed issues with understanding the data as it was presented on the graphs and not understanding the terminology used.

36 out of 310 participants were dissatisfied with "Clarity of Information"



Difficult to understand all the data arranged in that way.
LG&E, Information Clear rating = 4

The data could be presented better.
LG&E, Information Clear rating = 5

What's an "interval?" What do markers do? I feel that there's very little about the user interface explained.
LG&E, Information Clear rating = 4

Not sure what some of the information means.
KU, Information Clear rating = 3

Limited navigation and difficult to interpret.
LG&E, Information Clear rating = 2

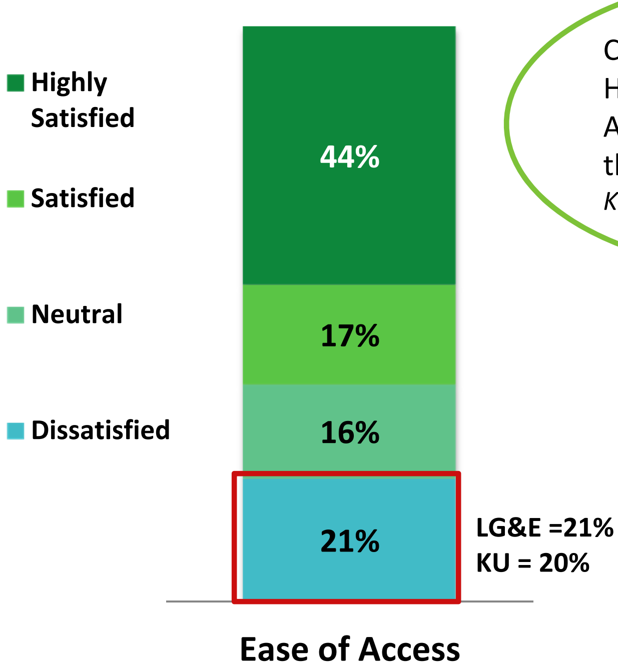
Hard to see hour by hour and day by day info.
LG&E, Information Clear rating = 5

Q4e. Why did you rate the clarity of the MyMeter dashboard information a **[Insert rating]**?

MyMeter Dashboard – Ease of Access

Many of the customers *Dissatisfied* with ease of access expressed a need to access MyMeter without going through the LG&E/KU website in order to minimize the number of clicks required to log-in. Some customers also expressed a desire to be able to access MyMeter via a mobile device.

64 out of 310 participants were dissatisfied with "Ease of Access"



I have to hunt all over to find it.
LG&E, Ease of Access rating = 1

No mobile. No login page that takes me directly there.
LG&E, Ease of Access rating = 1

Cannot log-in directly. Have to log-in on My Account then click 3 or 4 things to get to MyMeter.
KU, Ease of Access rating = 2

I would much rather have an app that doesn't require me to login to a web page.
LG&E, Ease of Access rating = 5

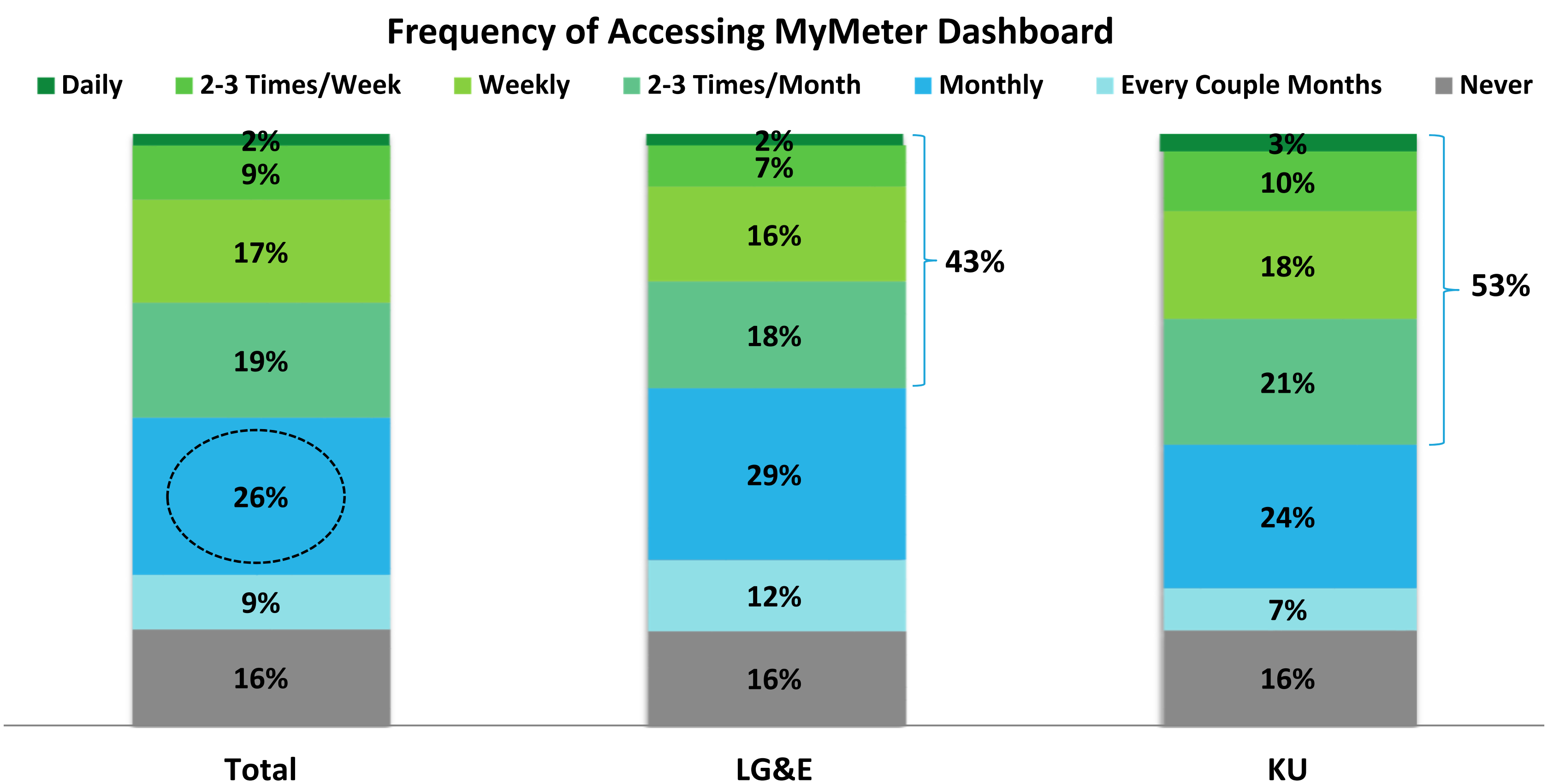
Takes several clicks to get to the dashboard.
KU, Ease of Access rating = 5

I always have to go through three different menus to find the advance meter dashboard.
KU, Ease of Access rating = 2

Q4c. Why did you rate the ease of accessing the MyMeter dashboard a **[Insert rating]**?

MyMeter Access Frequency

One-fourth of AMS participants reported accessing their MyMeter Dashboard on a monthly basis. Over half of KU customers access MyMeter more than once a month, ahead of LG&E customers. There were 16% of participants surveyed who reported never accessing the MyMeter Dashboard, consistent between LG&E and KU.

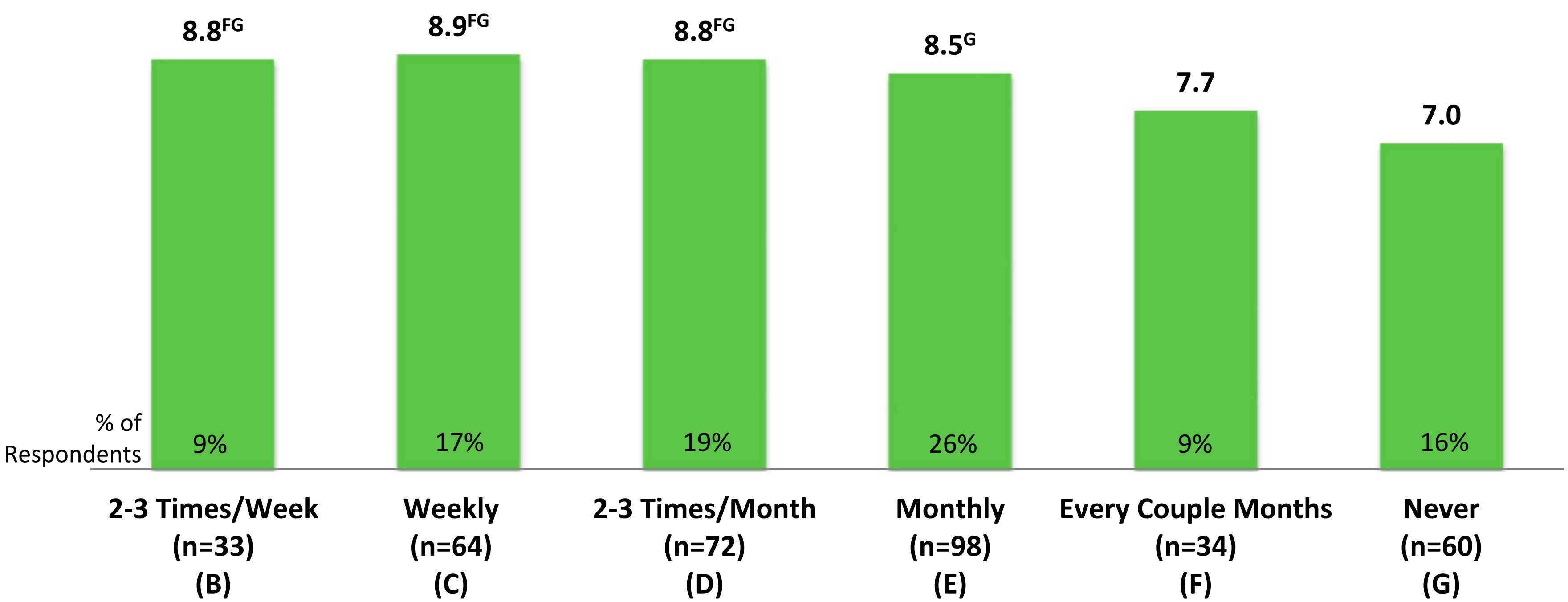


Q2. How frequently do you access the MyMeter dashboard?

Exhibit JPM-1, Appendix A-1
Page 24 of 45
Malloy

Satisfaction with AMS was rated significantly higher among customers who accessed the MyMeter Dashboard more frequently. Encouraging customers to access their MyMeter Dashboard weekly or a couple times a month could drive higher satisfaction with the service overall.

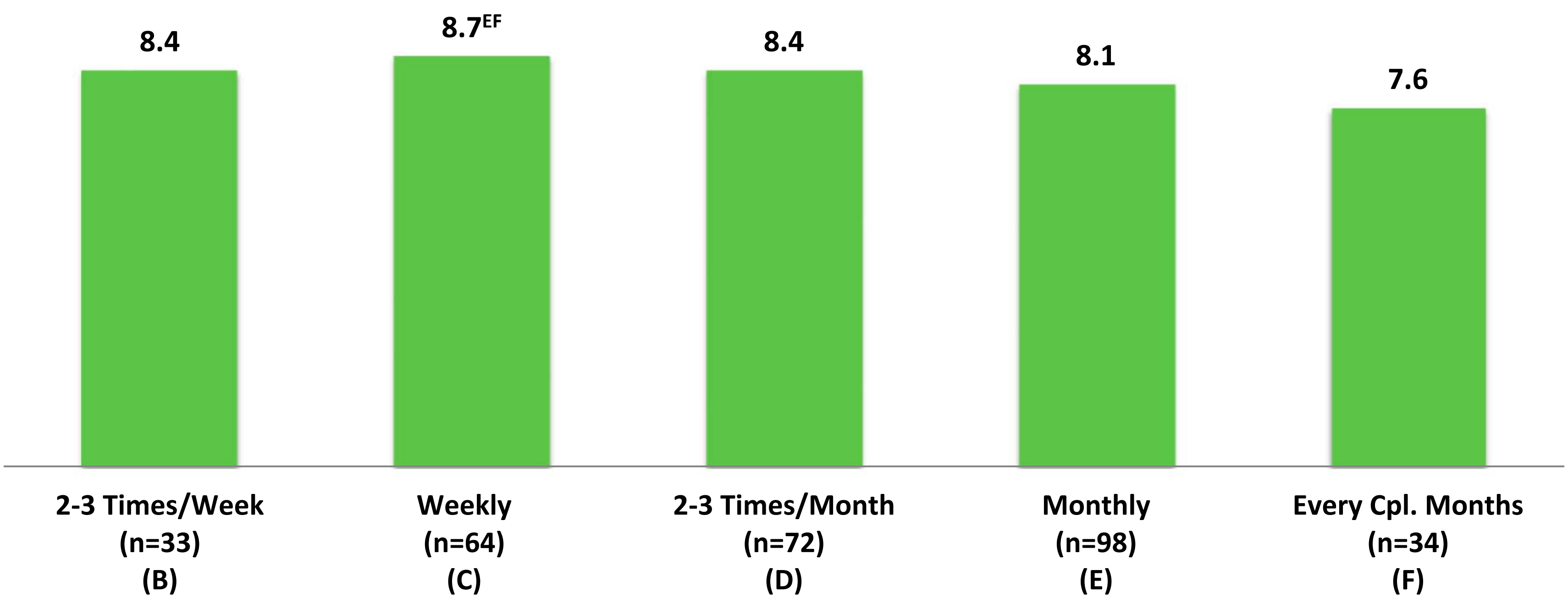
Overall Satisfaction with AMS by Frequency of MyMeter Access



Q1. Overall, how satisfied are you with the Advanced Meter Service?, Q2. How frequently do you access the MyMeter dashboard?
Letters indicate significant difference at 95% confidence level

Customers accessing MyMeter on a weekly basis reported highest satisfaction with the Dashboard. Slightly lower satisfaction among customers accessing 2 to 3 times per week could be due to the 2-day delay in reporting and possibly the desire for closer to real time usage data.

Overall Satisfaction with MyMeter by Frequency of Access*

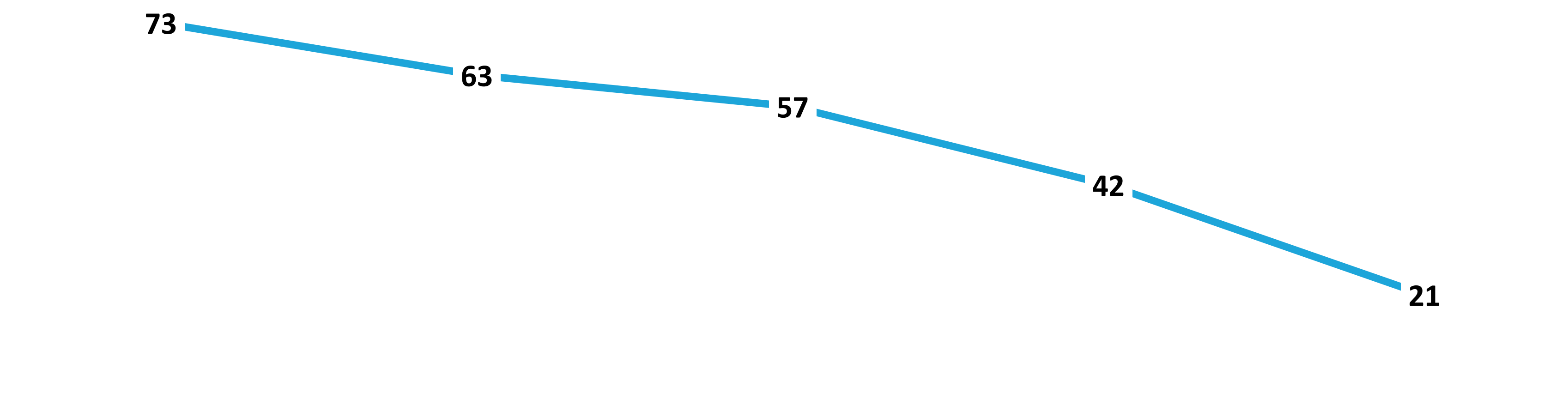


Q3. How would you rate your overall satisfaction with the MyMeter dashboard?, Q2. How frequently do you access the MyMeter dashboard?
Letters indicate significant difference at 95% confidence level
*Among customers who have accessed the MyMeter Dashboard (n=310)

Net Promoter Score – Likelihood to Recommend

In addition to driving higher Overall Satisfaction, Customers who are using the MyMeter Dashboard frequently are more likely to be a *Promoter* of Advanced Meter Service than those who access less frequently.

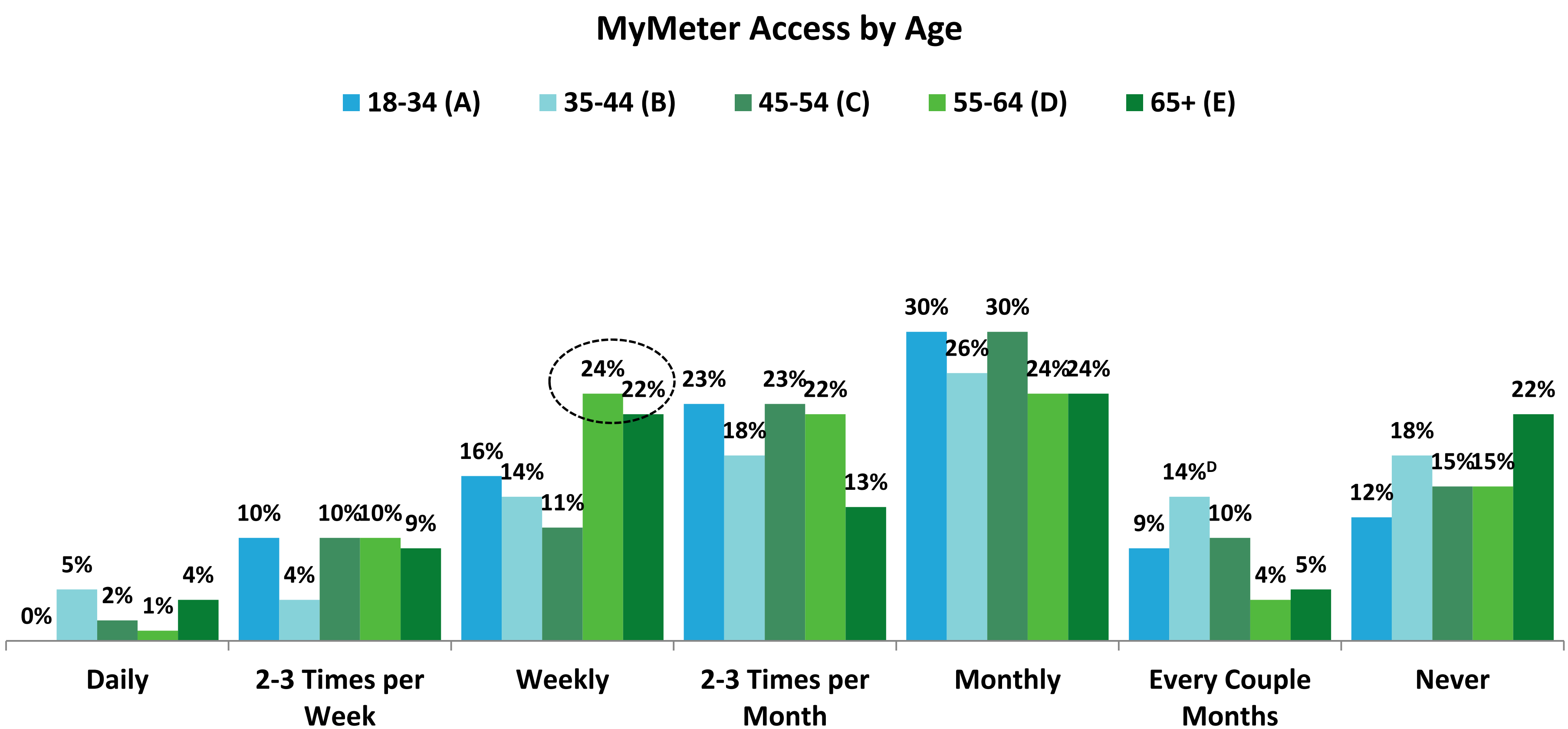
Net Promoter Score (NPS) by Frequency of MyMeter Access



	2-3 Times/Week (n=33) (B)	Weekly (n=64) (C)	2-3 Times/Month (n=72) (D)	Monthly (n=98) (E)	Every Couple Months (n=34) (F)
% Promoters	79%[EF]	69%[F]	65%	60%	47%
% Detractors	6%	6%	8%	18%[CD]	26%[CD]

Q11. How likely are you to recommend the Advanced Meter Service to friends or family?; Q2. How frequently do you access the MyMeter dashboard?
Letters indicate significant difference at 95% confidence level
*Among customers who have accessed the MyMeter Dashboard (n=310)

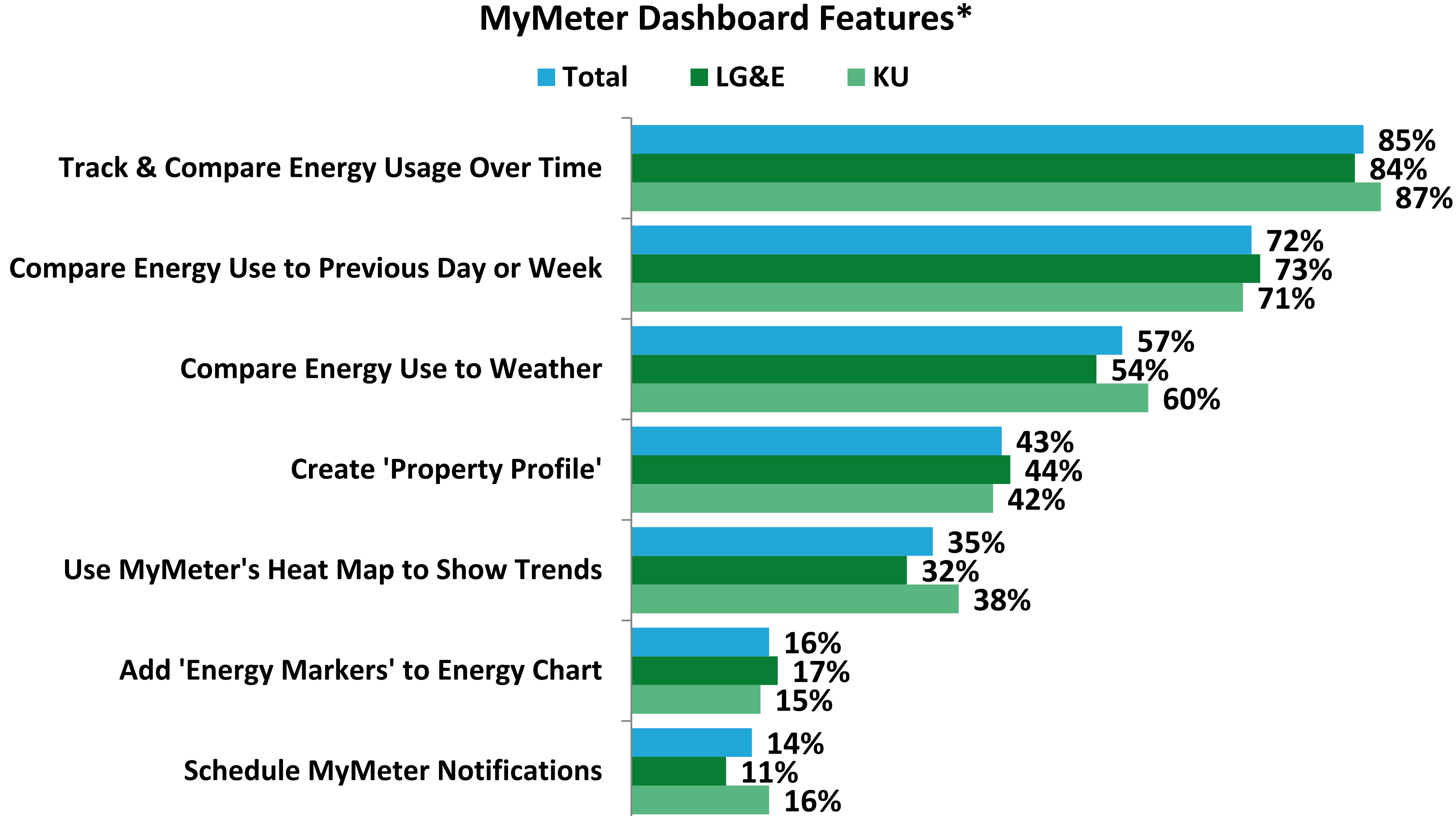
Older customers are slightly more likely to access the MyMeter Dashboard on a weekly basis than younger customers. Interestingly, the oldest customers (65+) were also slightly more likely to have never accessed MyMeter.



Q2. How frequently do you access the MyMeter dashboard?
C2. In what range does your age fall?
Letters indicate significant difference at 95% confidence level

MyMeter Access

Most customers are using MyMeter to track and compare their energy usage over time or to a previous day or week. Feature usage on MyMeter is similar for both LG&E and KU customers, with few customers using "Energy Markers" or scheduling notifications.



Q5. Which of the following features of the MyMeter dashboard have you used?
*Among customers who have accessed the MyMeter Dashboard (n=310)

MyMeter Access

Customers who stated they had **never** accessed the MyMeter Dashboard were asked a follow-up question regarding why they haven't accessed. Some customers responded that they were unfamiliar with MyMeter and/or did not know where or how to access the dashboard.

24 out of 60 participants said they *did not know* about the dashboard or how to access it

"I didn't know it existed."

"Didn't know where to access it or when it was available."

5 out of 60 participants said they were *new* to the program

"Just recently received, just not taken the time to do so."

7 out of 60 participants said they *forgot* about the dashboard

"I forgot how."

"I forgot about it and don't know how to easily relate the data to energy consumption."

8 out of 60 participants implied accessing the dashboard was *difficult*

"It was not easy to find the data on the website."

"Haven't had the time."

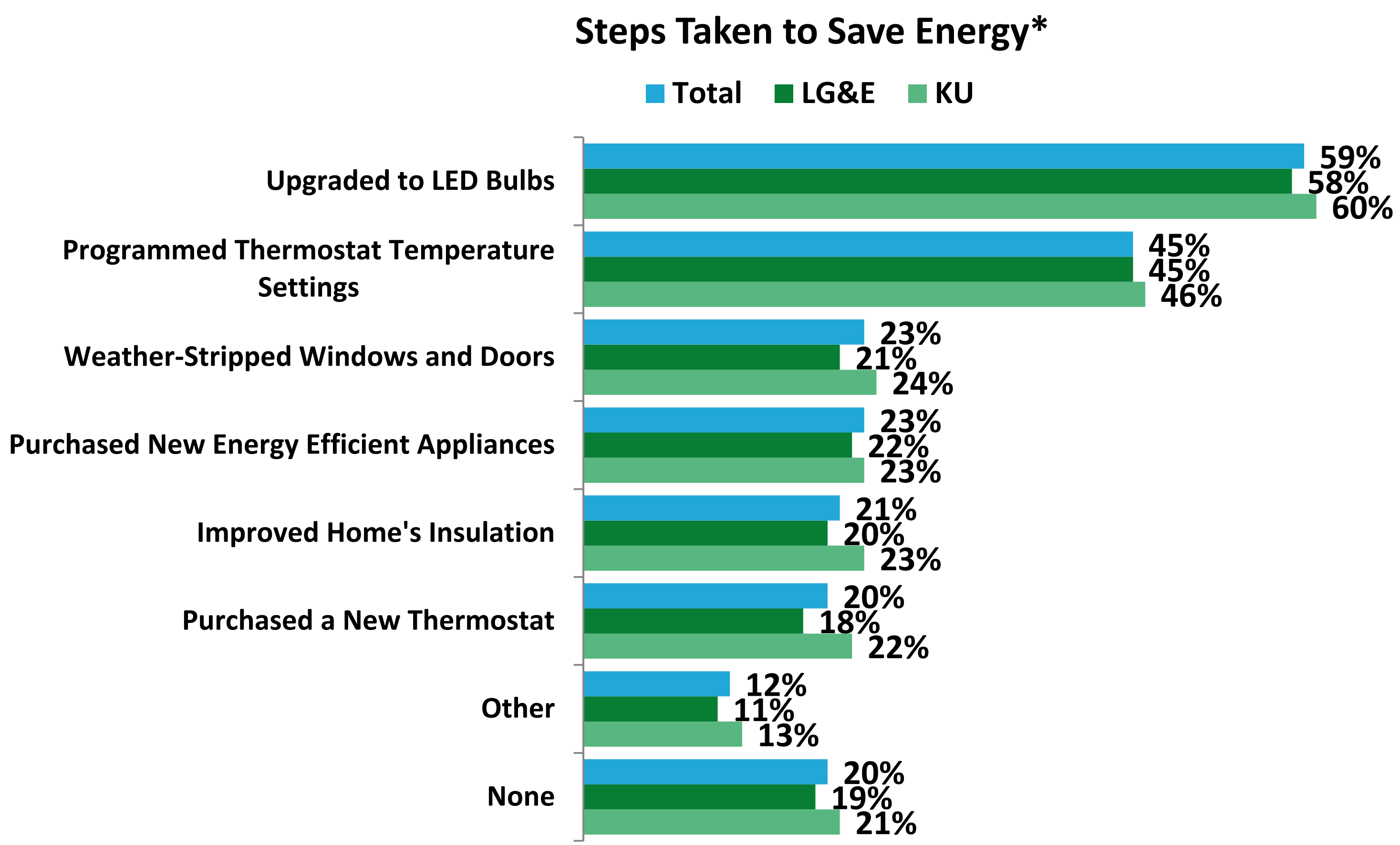
6 out of 50 participants said they did not have *time* to access the dashboard

Q2a. Why have you never accessed the MyMeter dashboard?
Note: 10 out of 60 participants chose not to provide a comment.

Participation Impact on Behavior

Participation Impact on Behavior

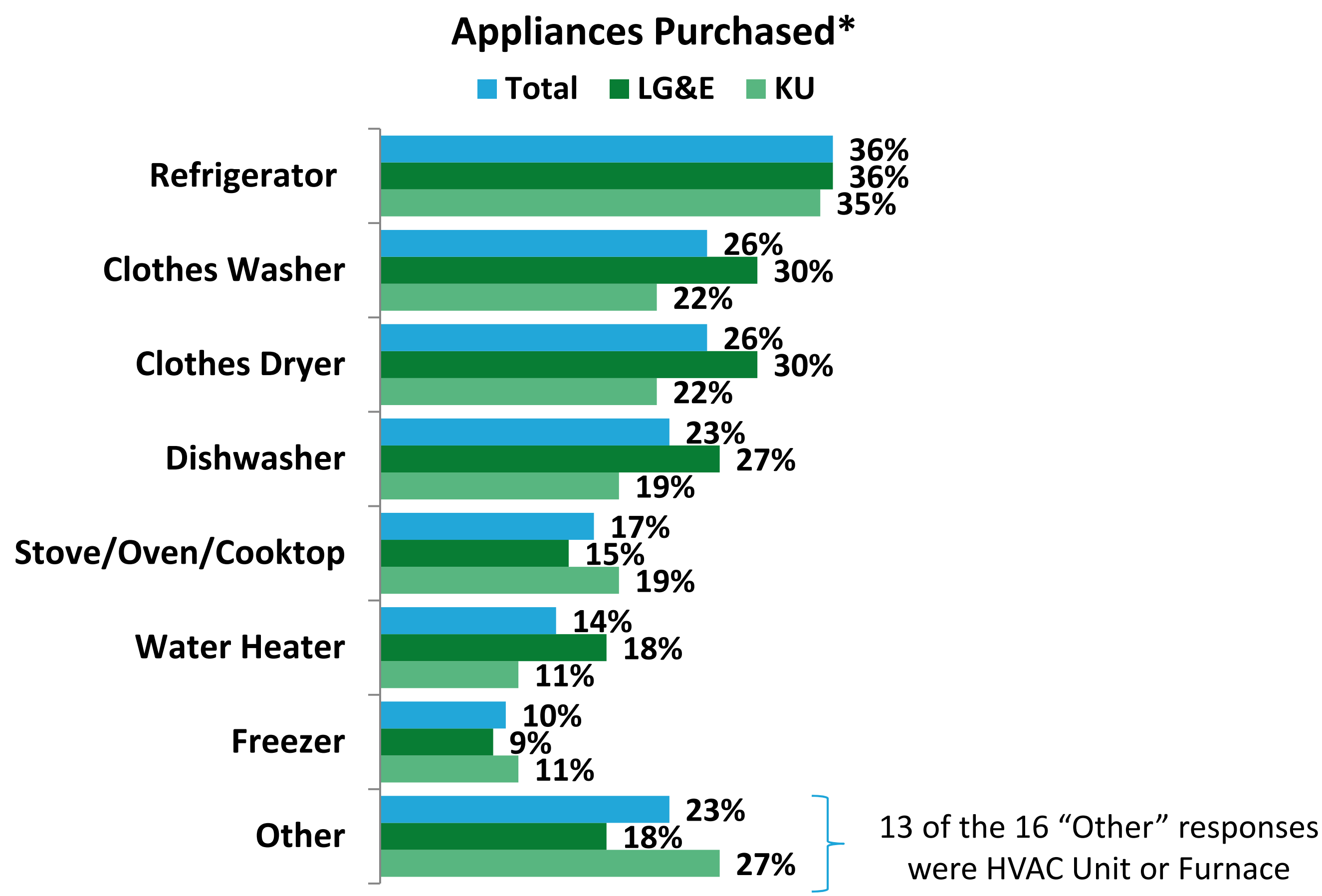
Many participants surveyed reported upgrading to LED Bulbs to save energy as a result of their participation in AMS. In addition, adjusting/programming thermostat temperature settings was mentioned by nearly half of those surveyed. However, one-fifth of participants stated they have taken no steps as a result of participation in AMS, similar for both LG&E and KU.



Q8. Which, if any, of the following steps have you taken to save energy as a result of your participation in the Advanced Meter Service?
*Among customers who have accessed the MyMeter Dashboard (n=310)

Participation Impact on Behavior

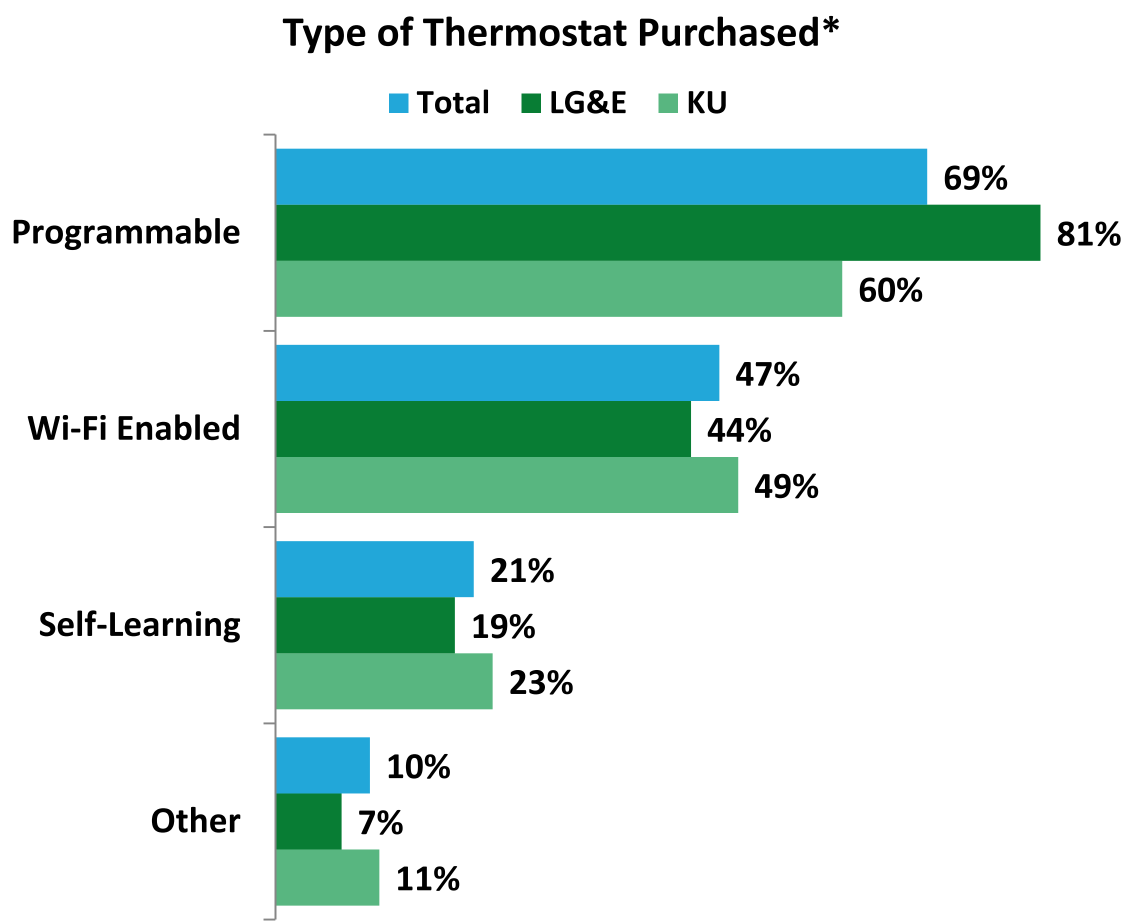
Among participants making an appliance purchase (23%), they mentioned a variety of appliances purchased since joining the Advanced Meter Service. Refrigerator purchases were the most common. The majority of "Other" responses were the purchase of replacement HVAC Units, Furnaces or Heat Pumps.



Q9. What type of appliances have you purchased since joining the Advanced Meter Service?
*Among customers who purchased new energy efficient appliances (n=70)

Participation Impact on Behavior

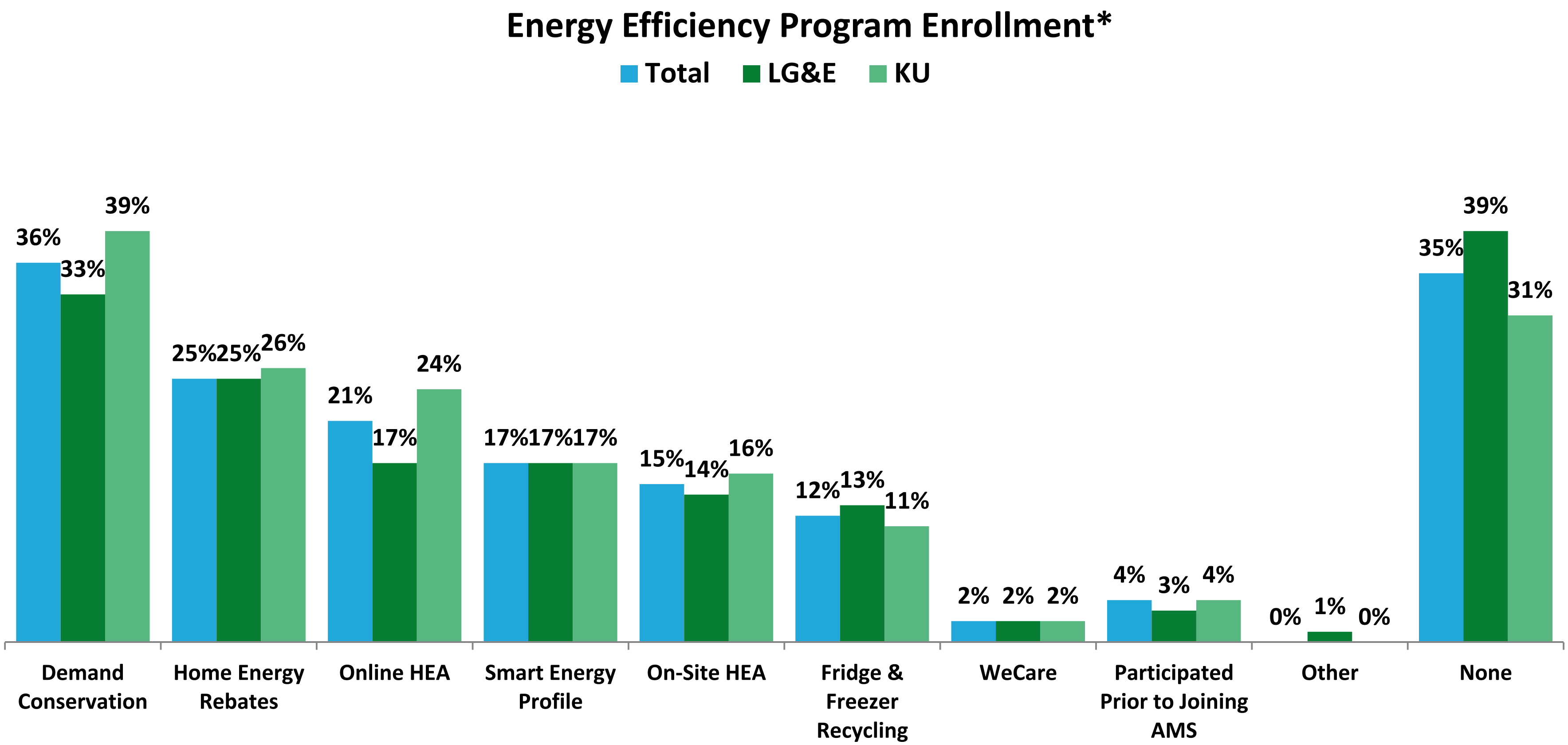
Among customers who purchased a new thermostat, the majority purchased a programmable thermostat. Only about one-fifth of new thermostats purchases were self-learning.



Q10. What type of thermostat did you purchase as a result of your participation in the Advanced Meter Service?
*Among customers who purchased a new thermostat (n=62)

Participation Impact on Behavior

Nearly 60% of participants surveyed reported enrolling in at least one Energy Efficiency program since joining AMS, especially Demand Conservation. KU customers were slightly more likely to enroll in Energy Efficiency programs than LG&E customers. About 5% of participants reported having enrolled in EE programs prior to their participation in AMS.



Q12. As a result of your participation in the Advanced Meter Service which, if any, of the following energy efficiency programs offered by **[LG&E, KU]** have you enrolled in?
*Among customers who have accessed the MyMeter Dashboard (n=310)

New Feature

PPL companies

New Feature

AMS participants surveyed were presented with the following description and images of the new MyMeter Dashboard feature which allows the option to review usage in terms of dollars ($), rather than just consumption (kWh). Respondents were then asked to rate their level of interest on a 5-point scale from "5 - Very interested" to "1- Not interested at all."

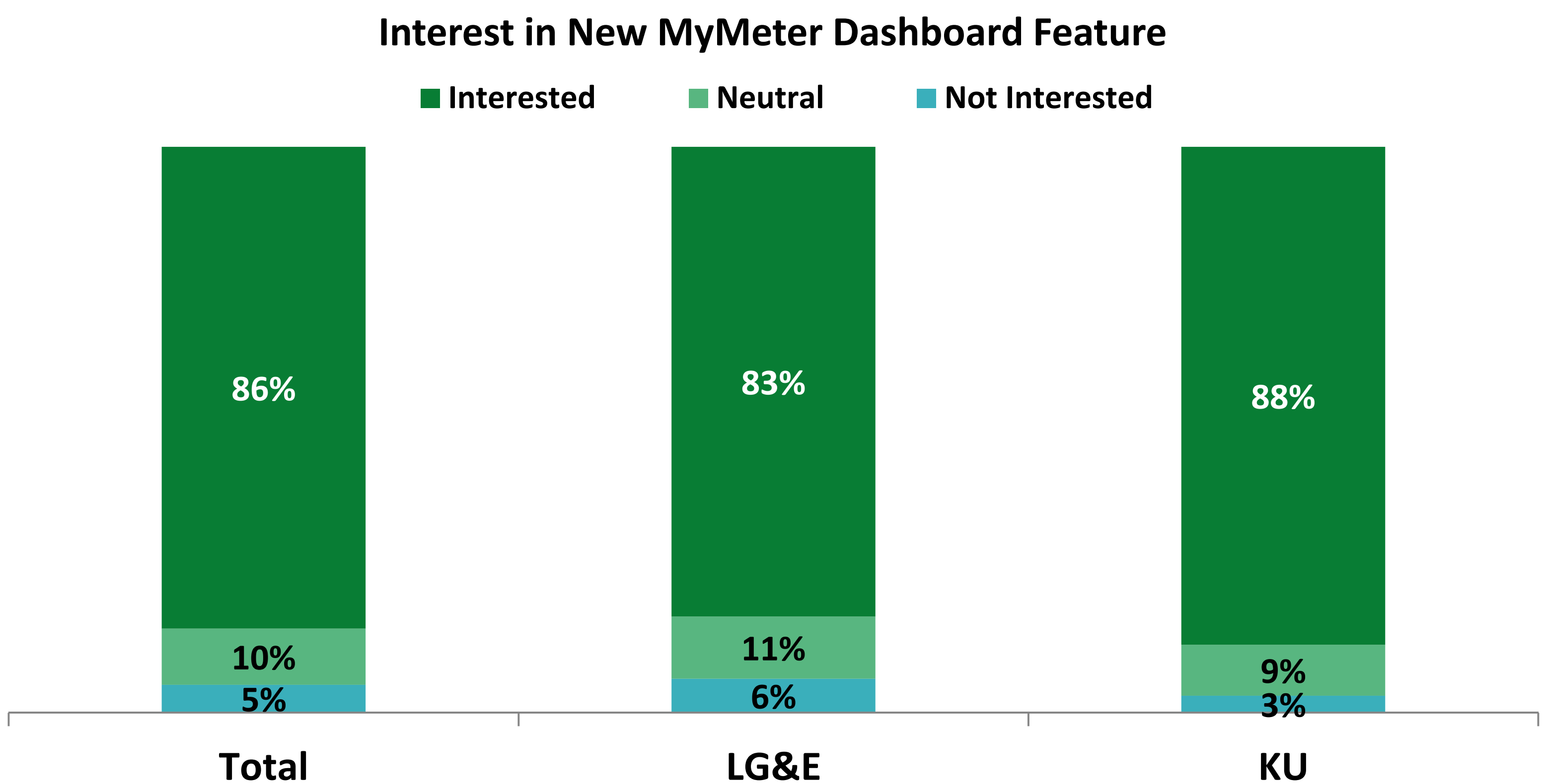
LG&E, Kentucky Utilities is considering adding a new feature to the MyMeter dashboard which will give you the option to review your energy usage in terms of dollars, rather than just consumption (kilowatt hours - kWh).

Financial information displayed in your MyMeter dashboard would only reflect your estimated electric charges, which is your billed amount (rate) multiplied by your electric usage (kWh). This information would not replace your actual bill, which reflects actual billing dates and additional electric charges that are itemized each month for your review.

Below is an image of the MyMeter dashboard as it exists today followed by how this new feature would look. You'll see that the monthly chart view changed from displaying consumption in terms of kWh to dollars. Please also note the language at the bottom of the screen.

Interest in New Feature

The majority of participants surveyed said they were *Interested* in the new MyMeter Dashboard feature, although KU customers were more interested than LG&E customers.



	Total	LG&E	KU
Mean	4.4	4.3	4.5 +

Q6. How interested are you in the new MyMeter dashboard feature shown?
Note: +/- indicates significant difference between LG&E and KU at 95% confidence level

Interest in New Feature

Participants surveyed were asked to explain why they gave their rating for level of interest. Customers who were *Interested* liked being able to see the dollar amount because their primary goal was to save money by monitoring usage. *Neutral* and *Disinterested* customers tended to be leery of the accuracy of the dollar amount and preferred to see a more consistent figure using kWh. Many liked being able to have the option to choose between kWh or dollars.

86% of participants were interested in the new MyMeter feature (n=317)

- Bottom line is how much money you are spending, right! That's a good number to have.
- Good to know dollar amount but it would be much better if the information showed BOTH dollar and kWh expended.
- Because I like to see how much money I can save, not kWh.

10% of participants were neutral in their interest for the new MyMeter feature (n=36)

- Once I am able to use the data, I will know if it is better to have the information in terms of dollars
- Actual energy kWh is a more accurate depiction of energy usage since the rate per kWh could go up and down it may not accurately depict changes.
- A kWh today is the same amount of energy as a kWh next year, but the dollars could change.

5% of respondents were not interested in the new MyMeter feature (n=17)

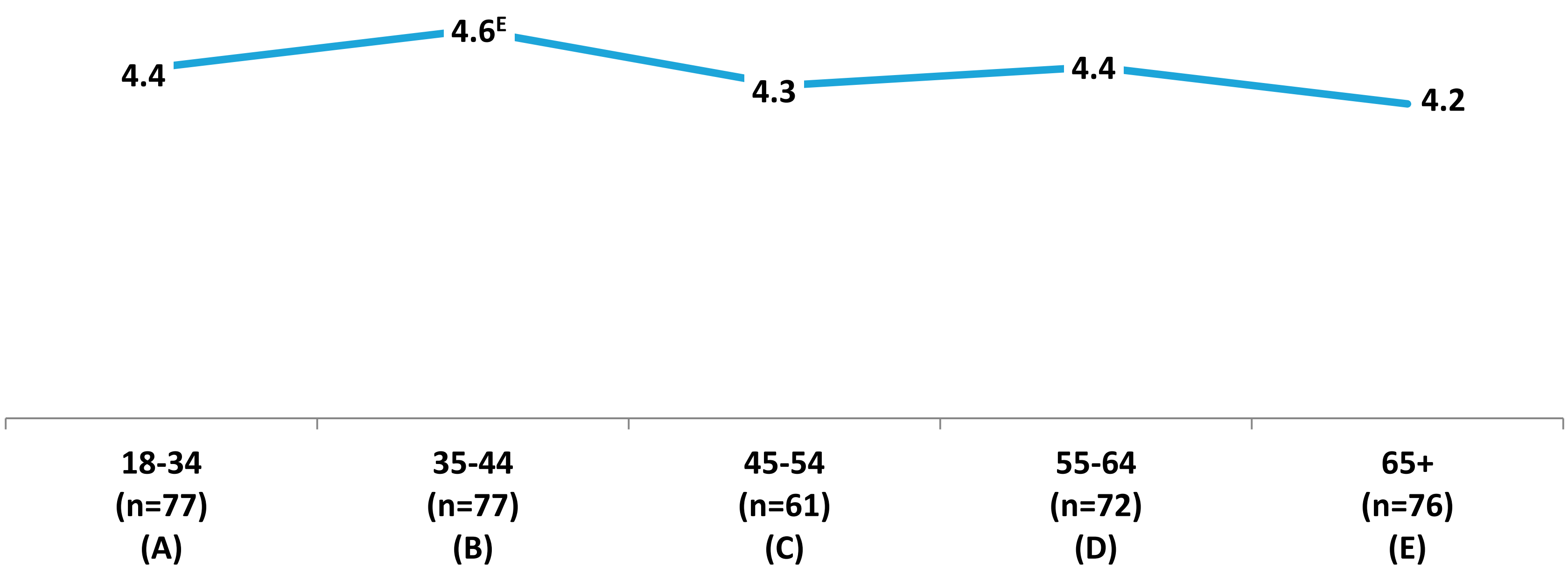
- I am more interested in kilowatt hrs. That is comparable across the country. It should be available both ways so we can choose.
- I'm more concerned about the usage and its impact on the environment than how much I pay.
- Energy prices change over time which can skew actual consumption figures.

Q6a. Why did you give this rating?
Caution: Low base sizes of less than 30 noted in red

Interest in New Feature

Participants ages 35 to 44 have the highest level of interest in the new feature, significantly ahead of the oldest age group (65+).

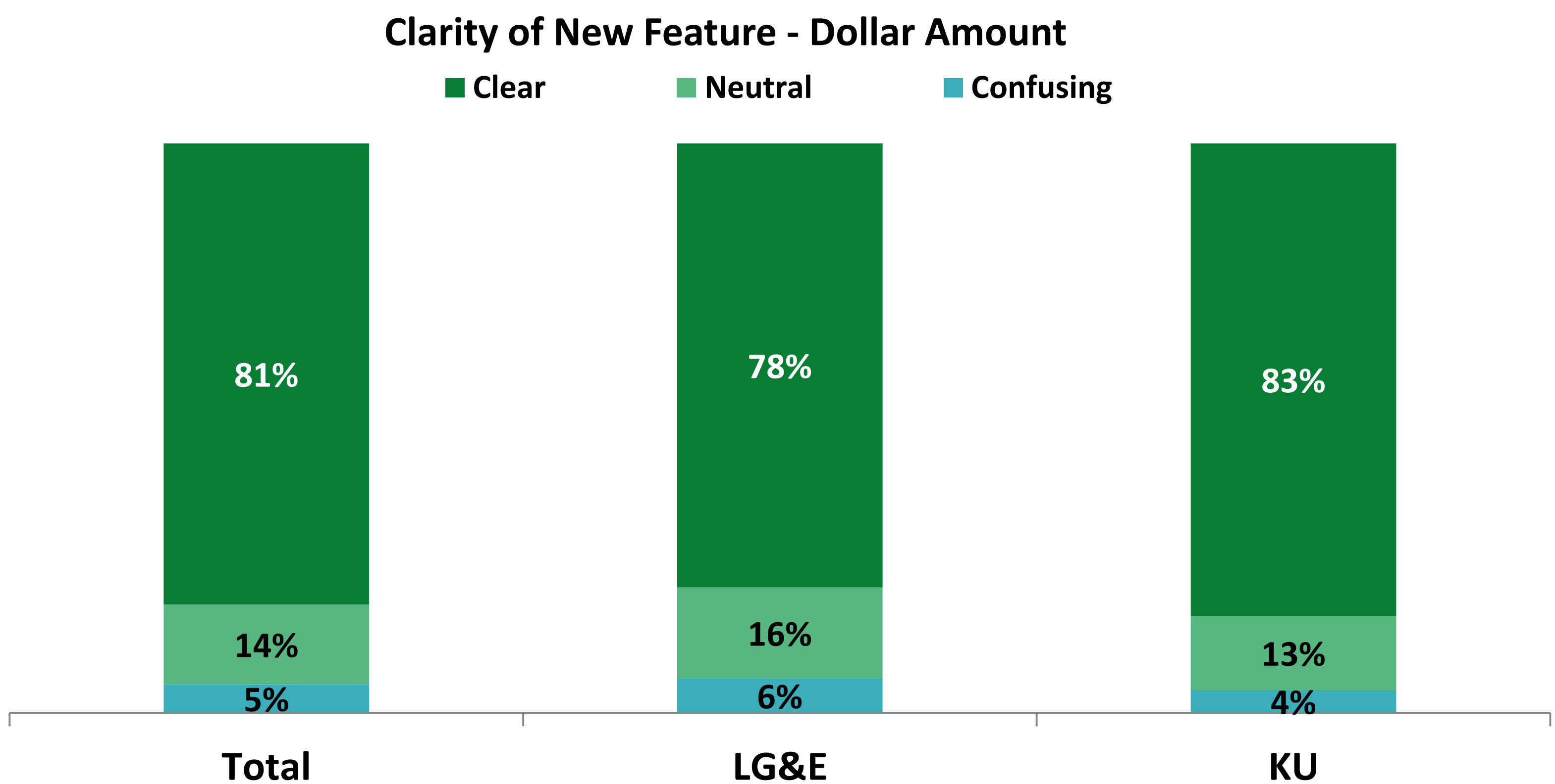
Interest in New MyMeter Dashboard Feature by Age



Q6. How interested are you in the new MyMeter dashboard feature shown?
C2. In what range does your age fall:
Letters indicate significant difference at 95% confidence level
Note: +/- indicates significant difference between LG&E and KU at 95% confidence level

Clarity of New Feature

Participants were also asked about clarity of the dollar amount using a 5-point scale from "5-Very Clear" to "1-Very Confusing." In total, 4 out of 5 participants surveyed felt the distinction between dollar usage and total bill amount was clear, with ratings similar between LG&E and KU customers.

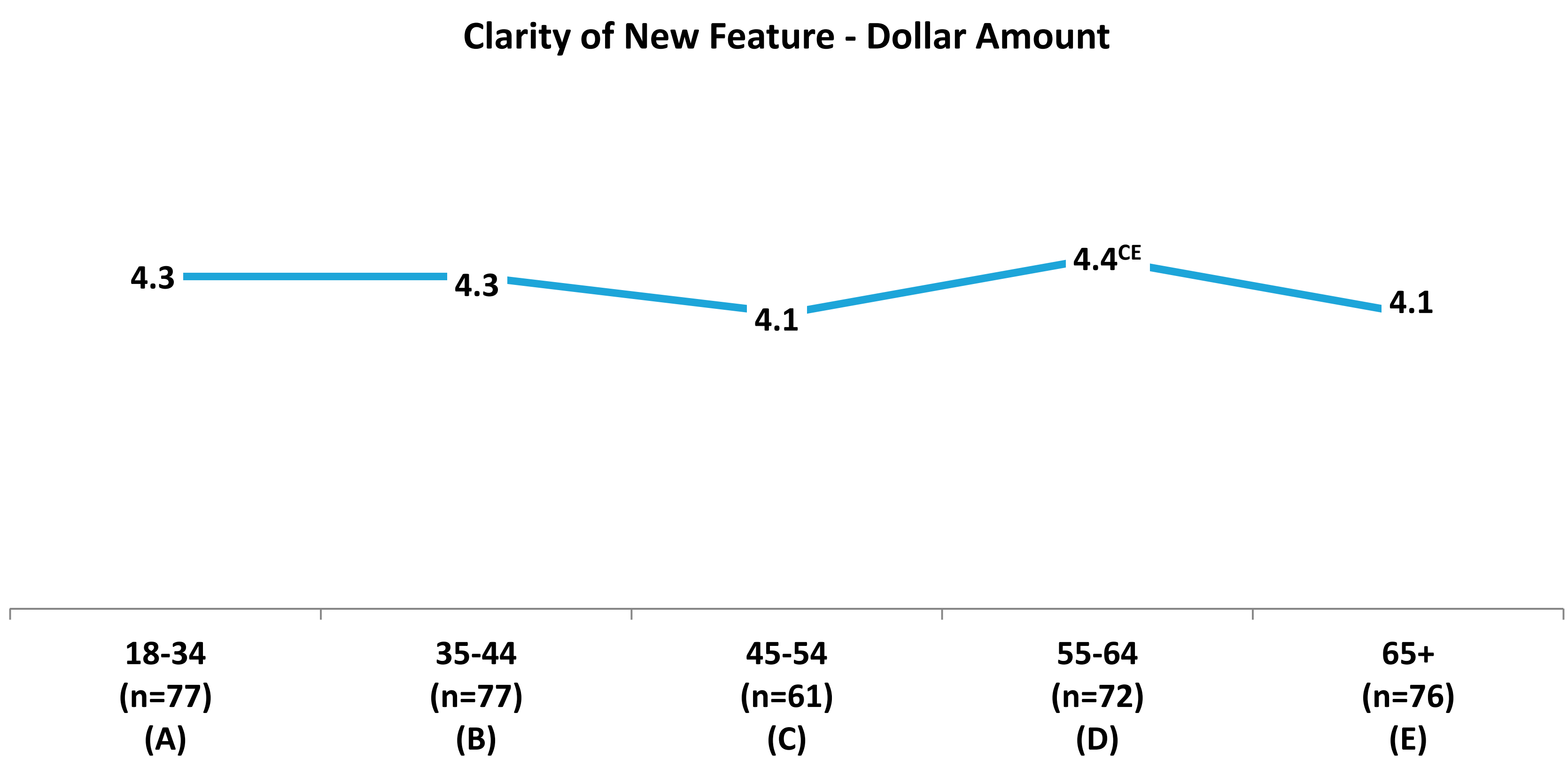


	Total	LG&E	KU
Mean	4.2	4.2	4.3

Q7. How clear is it that the dollar amount outlined in the feature refers to usage and not the total bill amount?

Clarity of New Feature

Participants ages 55 to 64 were most likely to rate the dollar amount outlined in the new feature to be clear, significantly ahead of the middle aged (45-54) and eldest (65+) customer groups.



Q7. How clear is it that the dollar amount outlined in the feature refers to usage and not the total bill amount?
C2. In what range does your age fall:
Letters indicate significant difference at 95% confidence level

Demographics

Demographics

	Total	LG&E	KU
Base	***370***	***179***	***191***
Living Space			
Under 800 Square Feet	3%	3%	3%
800 – 1,500 Square Feet	28%	35% +	22%
1,501 – 2,500 Square Feet	38%	37%	40%
2,501 – 3,500 Square Feet	17%	12% -	21%
Over 3,500 Square Feet	13%	12%	14%
Don't know	1%	1%	1%
Prefer not to answer	0%	0%	1%
Education			
High school graduate or equivalent	6%	7%	5%
Some college/technical school	16%	14%	19%
College graduate	40%	41%	39%
Graduate/post-graduate school	37%	37%	37%
Prefer not to answer	1%	2%	0%

Note: +/- indicates significant difference between LG&E and KU at 95% confidence level

Demographics

	Total	LG&E	KU
Base	***370***	***179***	***191***
Age			
Under 18	1%	1%	1%
18-34	21%	22%	20%
35-44	21%	25% +	17%
45-54	16%	17%	16%
55-64	19%	17%	22%
65+	21%	17%	24%
Prefer not to answer	1%	2%	0%
Income			
$40,000 or less	11%	9%	13%
Over $40,000	74%	78%	71%
Prefer not to answer	15%	13%	17%
Gender			
Male	74%	73%	75%
Female	24%	25%	23%
Prefer not to answer	2%	2%	2%

Note: +/- indicates significant difference between LG&E and KU at 95% confidence level

Appendix A-2

Illustrative Application Architecture

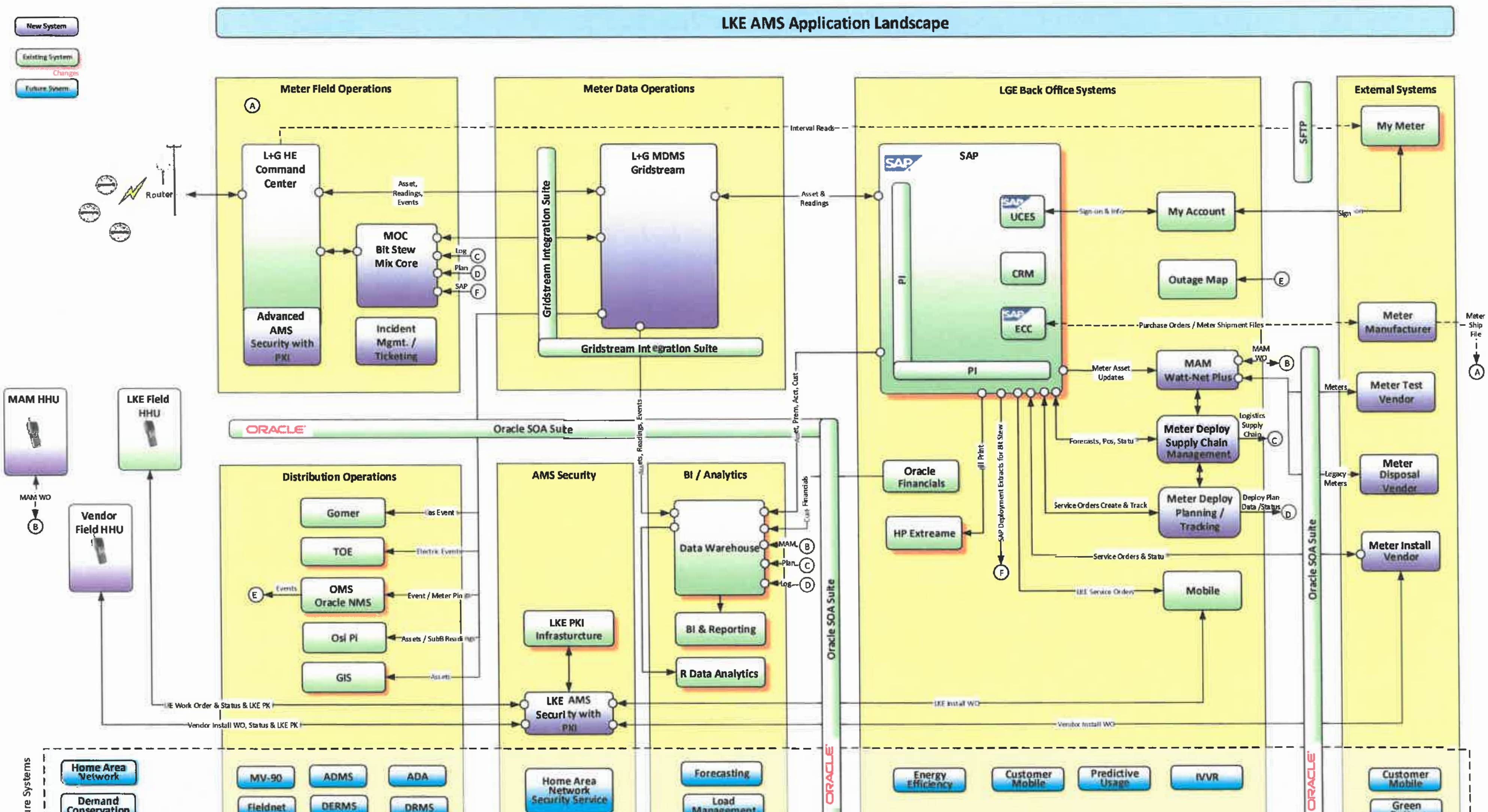


Exhibit JPM-1, Appendix A-2
Page 1 of 1
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Appendix A-3

Landis+Gyr Data Sheets

Appendix A-3.1

L+G Residential Endpoint Data Sheets

Product Specifications

Gridstream RF Mesh Residential Endpoints

Landis+Gyr
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Meter Platforms

FOCUS® AL
Enhanced FOCUS AX
Enhanced FOCUS AXe
G5 FOCUS AXe
Enhanced Elster REXU

Secure Intelligence Meets Residential Metering for Optimum Revenue and Greater Efficiencies

Overview

More options. More security. Landis+Gyr's Gridstream® RF Mesh Residential Endpoints deliver. Here's why: Delivering future-ready advanced metering automation solutions and enabling consumer energy management programs—you can expect optimized revenue and more efficiencies in a long-lasting solution.

The endpoint leverages its integrated design and advanced functionality to work with the meter and provide a direct, meter register read. The endpoint transmits and receives data via Gridstream's robust and self-healing mesh network, utilizing the 902 to 928 MHz FHSS unlicensed frequency. Our premier single- or poly-phase digital endpoints prioritize application-based messages, expand to millions of endpoints, and offer control through the intuitive, browser-based interface for streamlined network and data management.

In addition to kWh, kW and voltage readings, the endpoints report load profile, time-of-use periods and up to 5-minute interval data for billing, engineering and customer service applications. With the exception of the FOCUS AL platform, endpoints may be ordered with integral service disconnect and built-in, SEP certified, ZigBee® Home Area Network (HAN) interface.

The Generation 5 (G5) FOCUS AXe platform accommodates a standards based stack firmware, enabling use of non-proprietary network managers and tools.

FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

- Enhanced security – tilt/vibration tamper detection, magnetic/DC detection and complete optical port lockout
- Full two-way communication – on-demand or routine
- Scheduling of metrology available data
- Remote upgradeable application – eliminates on-site firmware and hardware changes
- Integral service disconnect with load limiting (AX-SD, AXe and REXU platforms)
- Advanced data support – demand, TOU, load profile, and voltage
- Voltage monitoring and reporting

Product Specifications: Gridstream RF Mesh Residential Endpoints

	FOCUS AL	Enhanced FOCUS AX	Enhanced FOCUS AXe	G5 Focux Axe	Enhanced Elster REXU
Electrical					
Voltage	120 or 240 V (depending on meter form)	9–16 V (from meter's power supply)	9–16 V (from meter's power supply)	3.8 V–4.2 V DC (from meter's power supply)	Nominal Voltage (+/-20%)
Power	Max: 2.8W (1.8W meter, 1W transceiver)	Max: 1.0W	Max: 1.0W	Max: 5.6W	Max: 3.0VA
	Typical: 2W (1.6W meter, 0.4W transceiver)	Typical: 0.6W	Typical: 0.6W	Typical: 0.5W	Typical: <1VA
RF 900 MHz					
Output Power	+26 dBm +/-1 dBm	+26 dBm +/-1 dBm	+26 dBm +/-1 dBm	+27 dBm +/-1dBm	+26 dBm +/-1 dBm
Adjacent Channel Power	+39 dBc Nominal	+39 dBc Nominal	+39 dBc Nominal	+40 dBc Nominal	+39 dBc Nominal
Transmit Frequency	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)
Receive Sensitivity	-108 dBm minimum	-108 dBm nominal	-112 dBm (typical, 9.6 kbps)	-114 dBm (typical, 9.6 kbps)	-110 dBm (typical, 9.6 kbps)
			-110 dBm (typical, 19.2 kbps)	-110 dBm (typical, 115.2 kbps)	-102 dBm (typical, 19.2 kbps)
				-99 dBm (typical, 300 kbps)	
RF ZigBee®					
Output Power	N/A	+20 dBm +/-2 dBm	+20 dBm +/-2 dBm	+20 dBm +/-2 dBm	+20 dBm +/-2 dBm
Adjacent Channel Power		40 dBc Nominal	40 dBc Nominal	40 dBc Nominal	40 dBc Nominal
Transmit Frequency		2405–2480 MHz	2405–2480 MHz	2405–2475 MHz	2405–2480 MHz
Communications Protocol		ZigBee Protocol	ZigBee Protocol	ZigBee Protocol	ZigBee Protocol
Receive Sensitivity		-104 dBm Minimum	-104 dBm Minimum	-104 dBm Typical	-104 dBm Minimum
Standards Compliance					
FCC Title 47 CFR Part 15	Radiated and Conducted Emissions (including intentional radiators)				
IEC 61000 4-2, 3, 4, 5, 11, 12	Electromagnetic Compatibility				
ANSI C12.19	Compatible with Utility Industry End				
ANSI C12.20-2002	National Standard for Electricity Meters – 0.2 and 0.5 accuracy class				
ANSI C12.1-2008	Code of Electricity Metering				
ANSI C37.90.1-2002	Standard Surge Withstand Capability (SWC) Tests				

COMPATIBILITY

Class	1S	2S	2SE	2K	3S	4S	9S(8)	12S(25)	12SE(25)	16S	16SE	36 S(6)	45S(5)
100	AL AX* AXe												
200	AXe* REXU*	AL AX* AXe*						AL AX* REXU*		AX			
320		REXU	AL AX AXe					AXe* REXU	AX		AX		
480				AL AX AXe									
10/20					AL AX AXe	AL AX AXe							
20					REXU	REXU	AX					AX	AX

**Switch Disconnect form available*

Phone: **678.258.1500**
FAX: **678.258.1550**

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Appendix A-3.2

L+G Commercial & Industrial Endpoint Data Sheets

Gridstream RF Mesh Commercial & Industrial Endpoints

Landis+Gyr
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Meter Platforms

Enhanced S4e
Enhanced S4x
Enhanced Elster A3
Enhanced GE kV2c

Options to Take Control of Advanced C&I Metering Applications

Overview

Robust, secure and future-proof. Landis+Gyr's Gridstream® RF Mesh Commercial & Industrial Endpoints bring electricity usage data to new levels.

The endpoint works with the polyphase meter to take advantage of advanced metrology and data values, while providing remote control of demand resets and TOU periods. The seamless integration delivers a direct read of the meter register to capitalized on advanced functionality.

The endpoint transmits and receives data through Gridstream's robust and self-healing, peer-to-peer mesh network, utilizing the 902 to 928 MHz unlicensed frequency. Endpoints prioritize messages based on application, expand to millions of endpoints and offer control through the inuitive, browser-based interface for streamline network and data management. Full two-way communication ensures commands are sent to the endpoint to reconfigure settings or upgrade firmware, without disrupting the meter data flow.

In addition to kWh, kW, time-of-use and voltage readings, the RF endpoint reports load profile and up to 5-minute interval data for billing, engineering and customer service applications. Endpoints come standard with ZigBee® transmitter for communication with in-premise devices.

FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

- Multiple options and enhancement capabilities via over-the-air or DCW upgrade
- Full, four quadrant meter ensures revenue optimization
- Enhanced security – optical port lockout feature with Gridstream communications, cover removal switch and magnetic tamper detection
- Reactive, TOU and two separate load profiles are standard on every S4X Meter
- Support for new enhanced metrology features, including 31 new load profile channels and four-quadrant reactive energy
- Full two-way communication – on-demand or routine
- Advanced data support – demand, TOU, voltage
- Voltage monitoring and reporting capabilities

Product Specifications: **Gridstream RF Mesh Commercial & Industrial Endpoints**

	S43	S4x	Elster A3	GE kV2c
Electrical				
Voltage	10.5-13.5V (From meter's power supply)	10.5-13.5V (From meter's power supply)	13.5VDC + 1V, 50mA (limited duration from meter's power supply)	28 VDC (From meter's power supply)
Power	Max: 2.5W Typical: 0.5W	Max: 1.0W Typical: 0.3W	Max: 3.0VA Typical: < 1VA	Max: 1.0W Typical: 0.3W
RF 900 MHz				
Output Power	+26 dBm +/- 1 dBm	+26 dBm +/- 1 dBm	+26 dBm +/- 1 dBm	+26 dBm +/- 1 dBm
Adjacent Channel Power	+39 dBc Nominal	+39 dBc Nominal	+39 dBc Nominal	+39 dBc Nominal
Transmit Frequency	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)	902 to 928 MHz ISM unlicensed (FCC Part 15)
Receive Sensitivity	-108 dBm minimum	-110 dBm (typical, 9.6 kbps); -102 dBm (typical, 19.2 kbps)	-110 dBm (typical, 9.6 kbps); -102 dBm (typical, 19.2 kbps)	-108 dBm minimum
RF ZigBee®				
Output Power	+20 dBm +/- 2 dBm			
Adjacent Channel Power	40 dBc Nominal			
Transmit Frequency	2405-2480 MHz			
Receive Sensitivity	-104 dBm Minimum			
Communications Protocol	ZigBee Protocol			
Standards Compliance				
FCC Title 47 CFR Part 15	Radiated and Conducted Emissions (including intentional radiators)			
IEC 61000 4-2, 3, 4, 5, 11, 12	Electromagnetic Compatibility			
ANSI C12.16	Dielectric (2.5kV, 60 Hz for 1 minute)			
ANSI C12.19	Compatible with Utility Industry End			
ANSI C12.20-2002	National Standard for Electricity Meters - 0.2 and 0.5 accuracy class			
ANSI C12.21	Optical port protocol with 128-bit AES Authentication			
ANSI C12.1-2008	Code of Electricity Metering			
ANSI C37.90.1-2002	Standard Surge Withstand Capability (SWC) Tests			
ANSI 62.41	High Voltage Line Surge (1.2 x 50 Isec)			

Compatibility

Class	Voltage	1S*	2S*	2SE	2K	3S	4S	5S	12S*	9S	12SE	15S	16S	25S	25SE)
10	120/480					S4e									
20	240/120/480					S4e, S4X	kV2c	S4e		S4e, S4X					
120													S4e		
200	120/480	S4X, kV2c	S4e, S4X, kV2c						S4e, S4X, kV2c				S4e, S4X, kV2c	S4e, S4X,	
320	120/480		kV2c	S4X, kV2c					kV2c		S4e, S4X				
480	120/480											S4e			

Appendix A-3.3

L+G Router Data Sheets

Gridstream RF Router

Landis+Gyr manage energy better

Advanced, Yet Cost-effective, Communication Solution

Overview

The Landis+Gyr RF Router helps form the powerful Gridstream® RF wireless mesh network used in Advanced Metering, Distribution Automation and Demand Response applications. Network performance and reliability are assured via the routers basic mesh functions including full two-way, peer-to-peer communication to all devices in the network, asynchronous spread spectrum frequency hopping and dynamic message routing.

The RF Router is designed to deliver enhanced on-board memory and communication speeds to support future application and development needs. In addition, advanced functionality enables individual message prioritization, automatic network registration and localized intelligence. The router can also provide distributed device control capabilities via programmable applets.

To provide critical network operations—even during small or widespread system power outages—a typical purchase includes battery backup integrated within the aluminum housing.

FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

- Interoperability to enable integration with numerous partners and supported devices
- Standards-based, including IPv6, to protect existing and future investments
- Individual message prioritization provides end device interfacing with other smart grid applications and functions
- Dynamic routing by each radio in the mesh network
- Data security and error-checking algorithms to assure integrity and reliability
- Downloadable code for easy, over-the-air firmware updates for near real-time monitoring and control

Specifications	
Size	11.82"W x 9.30"D x 4.07"H
Weight	Base – 5 lbs 8 oz (2.49 kg)
	Battery adds 2 lbs 8 oz (1.13 kg)
Operating Temperature	-40ºC to +85ºC (internal ambient of enclosure)
Power Supply	Operating AC Voltage – 96-317 VAC
	Input for Receive mode / 120VAC Operation – 15 mA (max)
	Input for Transmit mode / 120VAC Operation – 95 mA (peak), 25 mA (Avg)
	Input for Battery charging mode / 120VAC Operation – 30 mA (max)
RF Output Power	21, 25, 30 dBm (user selectable)
General Radio Items	Frequency Range – 902-928 MHz
	Channel Spacing – 100 kHz, 300 kHz, or 500 kHz (dependent on mode)
	Channels – 56, 80, 240 (dependent on mode)
	RF Baud Rates – 9.6, 19.2, 38.4, 115.2, 300 kbps
Battery	Backup Time – 8 hours, typical
	Backup – 12V SLA 2500mAhrs, nominal
	Life – 5–7 years, typical
Processing	CPU – ARM9
	SRAM – 16 MB
	Flash – 8 MB ANSI C12.1 Compliance
Approvals	FCC Certified Part 15.247
ANSI C12.1 Compliance	Operating vibration; operating shock; electromagnetic radiation emissions, electromagnetic susceptibility, surge withstanding capability, electrostatic discharge
Enclosure Material Type	Aluminum/NEMA-4, sealed
Standard Shipment Includes	White, die-cast aluminum all-weather enclosure
	Operation on DC (12/24 VDC) or AC power, with automatic switching between 120 VAC or 277 VAC when connected to power source
	RS-232/485 lines for both LPPx and transparent port communication
	Standard N-Female antenna connector
	Integrated filter for attenuation of out-of-band interference
	Mounting hardware

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Appendix A-3.4

L+G C6500 Collector Data Sheets

Product Specifications

Gridstream C6500 RF Collector

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C6500 RF Collector
Ethernet only

C6530 RF Collector
with CDMA/EVDO wireless modem

Versatile and Cost-Effective Communication Solution

Overview

Ease of installation and dependable design make the Gridstream® C6500 Collector a cost-effective, workable option for efficient communication between Gridstream RF endpoints, routers and the Command Center server, while performing all necessary functions of the standard data collector.

The C6500 can be installed in a variety of locations and is configured to accept public backhaul communication options. The C6500 can be ordered with an internal CDMA/EVDO wireless backhaul modem or without a modem in cases where an Ethernet connection is available.

FEATURES & BENEFITS:

Why Landis+Gyr makes a difference.

- Interoperability to enable integration with numerous partners and supported devices
- Standards-based, including IPv6, to protect existing and future investments
- Integrated wireless radio backhaul modem
- Data security and error-checking algorithms assure integrity and reliability
- Simpler and reduced installation time
- Dynamic routing by each radio in the mesh network
- Downloadable code for easy, over-the-air firmware upgrades and near real-time monitoring and control

Product Specifications: **Gridstream C6500 RF Collector**

Specifications	
Dimensions (excludes antennas)	5.04"H x 11.82"W x 9.30"D
Antennas	Two (2), one blackhaul (top) and one (1) Gridstream (bottom)
Antenna Height Minimum	20 ft.
Weight	9.6 lbs.
Standard Compliance	FCC Part 15, Class B
Operating AC Voltage	96-277 Vrms
Power Consumption	9W typical – batteries not charging
	18W typical – batteries charging
Operating Frequency Band	902-928 MHz, unlicensed
Transmit Output Power	1W maximum for single IWR radio
Baud Rate Range	9.6, 19.2, 38.4, 115.2, 300 kbps
Endpoint Capacity (initial)	4,500
Processing	CPU – ARM 9
	Internal Memory – 16 MB
	Flash – 8 MB
Operating Temperature	-40ºC to 60ºC, outdoors
Storage Temperature	-40ºC to 85ºC
Color	White
Enclosure Material/Type	Aluminum/NEMA-4, sealed
Battery	Backup Time – 8 hours, typical
	Backup – LiFePO4 cells in a 4s4p arrangement, 13.2V, 10000mAhrs nominal
	Life – 15 years, maintenance free
Backhaul Communications	Integrated wireless CDMA/EVDO or wired Ethernet connection
Supplied Cellular Carriers	C6530: Verizon or Sprint
Mounting Options	Utility poles and streetlights

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Appendix A-3.5

L+G C7500 Collector Data Sheets

Gridstream
C7500 RF Collector

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Extended Data Collection Capabilities for RF Mesh Systems

Overview

With enhanced on-board memory and faster communication speeds, the Gridstream® C7500 Collector is a powerful and flexible data collection and control center for users of Landis+Gyr's RF Mesh advanced metering systems.

The collector is designed to actively monitor up to 25,000 endpoints simultaneously to continuously communicate unique commands to individual endpoints, in both defined groups or across the entire network. Data is received from network routers and endpoints to provide a conduit for system hosting via Internet packets.

Installation options of the secure NEMA-4 collector include a distribution substation, wood utility pole, steel monopole, radio tower or in a rack. In addition, the C7500 is designed to support future applications and upgrades and can accommodate a variety of communications options to the utility including RF, fiber, cellular and microwave with the use of a WAN modem.

FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

- Simultaneously monitors to up to 25,000 AMI endpoints in Gridstream environments
- Auto-baud rates enable uninterrupted data communication regardless of RF link quality changes
- Maximizes bandwidth use with asynchronous spread spectrum frequency hopping
- Packet switching guarantees message transfer with automatic store and forward routing
- Auto-notification of power outage and restoration across entire AMI system

Product Specifications: **Gridstream C7500 RF Collector**

Specifications	
Collector Dimensions	18"H x 17.5"W x 11"D (excludes antennas)
Weight	51 lbs.
Antennas	Four (4), remote RF Mesh Antennas, Antenex FG 9023 (typical)
Input Voltage	Selectable: 120/240 +/-20%
Input Current	1A typical at 120V
Power Consumption	48W maximum, 20W typical
Operating Frequency Band	902-928 MHz, Unlicensed
Transmit Output Power	1W maximum for each IWR
Standards Compliance	FCC Part 15, Class B
Operating Temperature	-40°C to +85°C (maximum local internal ambient temperature)*
Storage Temperature	-40°C to +85°C
Color	Gray
Enclosure Material/Type	Aluminum/ NEMA-4, Lockable
Backup Battery	SLA, 12V, 13 Ah
Backhaul Data	Ethernet 10/100T
Mounting Options	Rack Mount, Utility Pole, Pad Mount, Roof Top, Unistrut Frame, other

*-40C to +60C outdoors, direct sunlight; -40C to +70C indoors or out of direct sunlight

Gridstream Series V Radio Specifications	
Electrical (General)	
Input Voltage Range	6 – 28 VDC
Input Current (in transmitting mode)	320 mA typical (12 VDC operation)
Input Current (in receiving mode)	38 mA typical (12 VDC operation)
RF Frequency Range	902-928 MHz
Channel Spacing	100, 300 or 500 kHz depending on the mode
RF Data Rate	9.6, 19.2, 38.4, 115.2, 300 kbps
Receiver	
Sensitivity (at 10% packet error rate)	-112 dBm (9.6 kbps) Typical
	-101 dBm (115.2 kbps) Typical
	-95 dBm (300 kbps) Typical
Co-channel Rejection	10 dB Typical
Adjacent Channel Rejection	30 dB Typical
Alternate Channel Rejection	45 dB Typical
Transmitter	
Output Power (at Antenna Connector)	21/25/30 dBm (user selectable)
Modulation Type	2-FSK, GFSK
Modulation Index	1
Out-of-band Spurious Emissions	<-70 dB

Appendix A-3.6

L+G Residential Gas Module Data Sheets

Product Specifications

Gridstream: M120 RF Residential Gas Module

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Two-way Residential Gas Metering for Network Continuity

Overview

The M120 RF Residential Gas Communications Module provides two-way AMI communications over Landis+Gyr's scalable, secure and interoperable Gridstream® RF Mesh network. The module is designed to record and communicate both total consumption and one channel of interval data. The data can be used to empower utilities to offer flexible rates and assist with capacity planning.

The M120 gas module simplifies deployment by automatically registering on the Gridstream network upon installation, eliminating the need for field installation tools. The M120 module mounts on most any residential gas meter built since the 1950's. In addition, the module is programmed to transmit data once a day.

The M120 gas module is designed to communicate with electric meters, routers or radios on distribution automation devices. This flexibility is key for utilities to maximize the benefits of Gridstream and manage multiple types of endpoints on a single network.

With a 20-year battery life, the M120 gas module ensures years of customer service.

FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

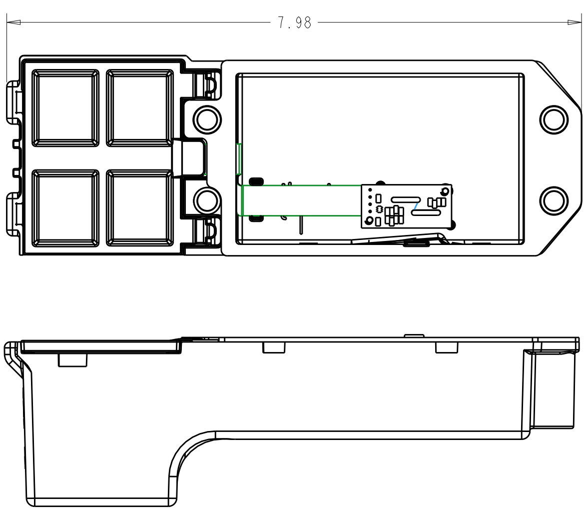
- Leverages full potential and scalability of Gridstream AMI network
- Fits most common residential gas meters and uses existing index
- No field programming, special field tools or costly infrastructure add-ons required
- Performs self-diagnostics
- Variety of event settings available to inform of module issues such as low battery
- Enhanced range (250 mW output)
- Plug-and-play activation keeps deployment on-schedule
- Interoperable for future advancements in gas measurement
- Produces one channel of load profile data which can be used for advanced rates, such as time of use

Product Specifications: **Gridstream M120 RF Residential Gas Module**

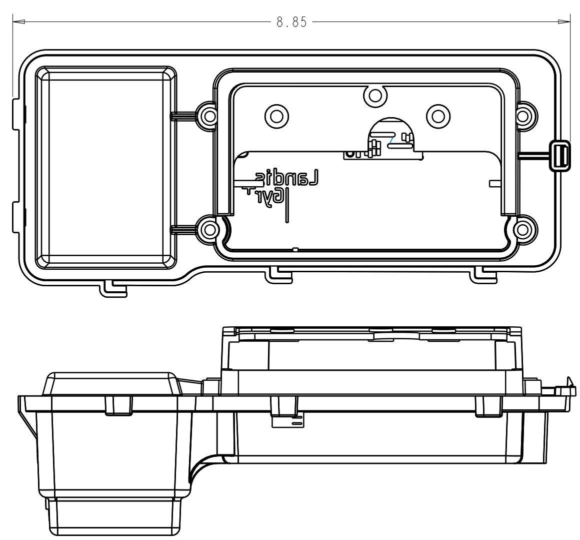
Specifications

Power Supply	Two “A” lithium manganese dioxide batteries	
	20-year battery life	
Environmental Temperature Rating	-40ºC to +85ºC	
Environmental	Relative humidity 0% to 100%	
RF Standards	FCC Part 15.247	
	Frequency; 902 – 928 MHz unlicensed	
	Baud Rate: 9600 to 38400 BPS	
ANSI Standards	B109.1-2000 Compliance	
	B109.2-2000 Compliance	
UL	Class 1, Division 1, Group D	
Data Transmission	The data is transmitted once per day. Each transmission includes last 24 hours of 15-minute interval data and last consumption value.	
Events Included	Tamper detection	
	Tilt switch	
	Consumption rollover	
	Low battery	
	Stale register	
	Extreme temperature change	
	Cover off	
Universal Retrofit	**Model**	**Meter Manufacturer**
	M120-1	Elster (American)
	M120-2	Itron (Actaris/Schlumberger/Sprague)
	M120-3	Sensus (Invensys/Equimeter/Rockwell)
	M120-4	National
Interval Data	45 days of one-channel,15 minute LP data	

American



Sprague



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Appendix A-3.7

L+G Commercial & Industrial Gas Module

Data Sheets

Gridstream:
M220 RF Commercial & Industrial Gas Module

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Two-way C&I Gas Metering for Utility Efficiency

Overview

The M220 RF C&I Gas Communications Module provides two-way AMI communications over Landis+Gyr's scalable, secure and interoperable Gridstream® RF Mesh network. The module is designed to record and communicate both total consumption and two channels of interval data (configurable for 15 and 60 minutes). Interval data can be used to empower utilities to offer flexible rates and assist with capacity planning.

The M220 gas module simplifies deployment by automatically registering on the Gridstream network upon installation, eliminating the need for field installation tools. The M220 module also utilizes "Plug and Play" technology allowing accurate count from time of installation, until the pulse input configuration parameters are received over the network. In addition, the module is programmed to transmit data once a day.

The M220 gas module is designed to communicate with electric meters, routers or radios on distribution automation devices. This flexibility is key for utilities to maximize the benefits of Gridstream and manage multiple types of endpoints on a single network.

With a 20-year battery life, the M220 gas module ensures years of customer service.

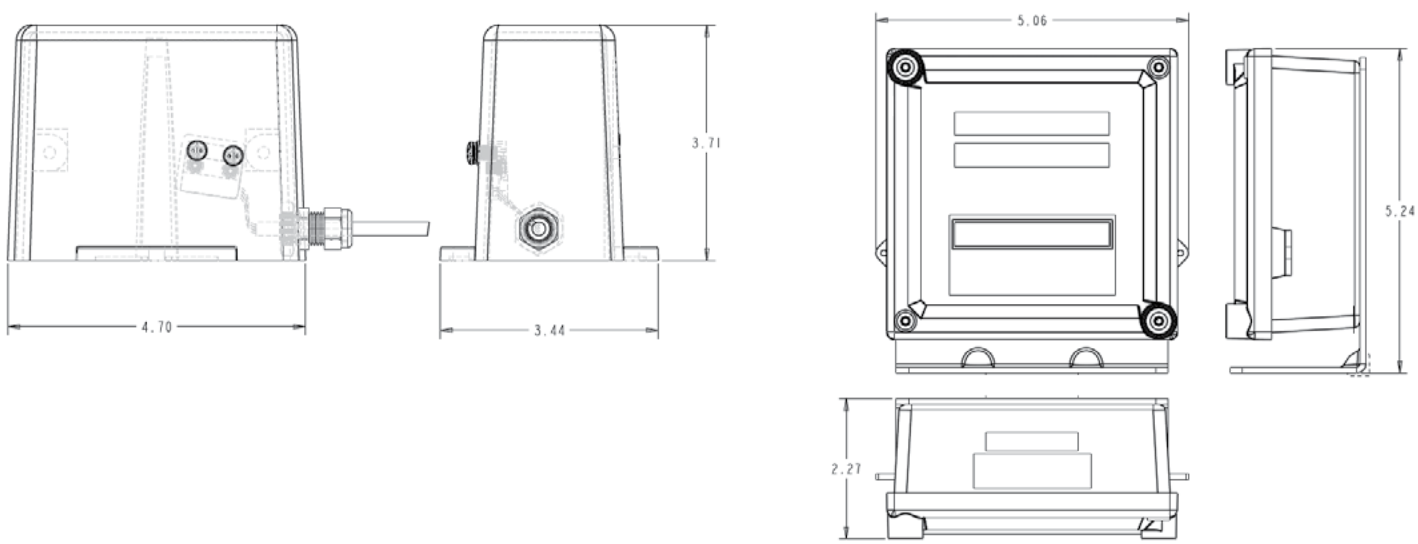
FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

- Leverages full potential and scalability of Gridstream AMI network
- Fits most common C&I gas meters and uses current indexes
- No field programming, special field tools or costly infrastructure add-ons required
- Performs self-diagnostics
- Variety of event settings available to inform of module issues such as low battery
- Enhanced range (250 mW output)
- Plug-and-play activation keeps deployment on-schedule
- Interoperable for future advancements in gas measurement
- Provides up to two channels of load profile data which can be used for advance rates, such as time of use

Product Specifications: **Gridstream M220 RF C&I Gas Module**

Specifications		
Power Supply	Four "A" lithium manganese dioxide batteries	
	20-year battery life	
Environmental Temperature Rating	-40ºC to +85ºC	
Environmental	Relative humidity 0% to 100%	
RF Standards	FCC Part 15.247	
	Frequency: 902 – 928 MHz unlicensed	
	Baud Rate: 9600 to 38400 BPS	
ANSI Standards	B109.1-2000 Compliance	
	B109.2-2000 Compliance	
UL	Class 1, Division 1, Group D	
Data Transmission	The data is transmitted once per day. Each transmission includes last 24 hours of 15-minute interval data and last consumption value.	
Events Included	Tamper detection	
	Tilt switch	
	Sensor failure	
	Low battery	
	Stale register	
	Extreme temperature change	
	Cover off	
Universal Retrofit	**Model**	**Meter Manufacturer**
	M220-1	Elster (American)
	M220-2	Itron (Actaris/Schlumberger/Sprague)
	M220-3	Sensus (Invensys/Equimeter/Rockwell)
Interval Data	45 days of two-channel,15 and 60 minute LP data	

American M220-1



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Appendix A-3.8

L+G Commercial & Industrial Pressure and Temperature Module Data Sheets

Gridstream GPR-PT Commercial & Industrial Pressure and Temperature Monitoring Module

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Two-Way C&I Pressure and Temperature Intelligent Energy Management

Overview

The Gridstream® Recorder for Pressure and Temperature (GPR-PT) C&I Gas Communications Module provides two-way communications over Landis+Gyr's scalable, secure and interoperable Gridstream RF Mesh network. The two-way gas module records and communicates up to four channels of interval data (configurable for 15, 30 and 60 minutes). A serial Modbus (RS-232) connection is used to communicate with correctors and pressure trackers. Select correctors from Mercury/Honeywell and Eagle Research Inc. are supported. Four dynamic channels can be programmed to record Pressures, Temperature, Corrected and Uncorrected Volumes, and Voltages from the attached device. Data that is recorded can be pushed to the Head End System every 1, 2, 4, 6, 8, 12 and 24-hour period for efficient system monitoring.

The module works with most devices within the Gridstream wireless mesh network – including electric meters, routers or radios on distribution automation devices – to send and receive information.

The module uses the unlicensed FCC part 15 902-928 MHz band to transmit using frequency hopping, spread spectrum technology. For efficiently manage energy consumption, the module is programmed to periodically report customer usage profiles and accept system configuration changes.

Fast, Easy Installation and Operation

- Auto-Registration
- No Field Programming or special field tools required
- Over-the-Air Firmware Upgrade
- On-Request Data Reads
- Flexible Mounting Bracket

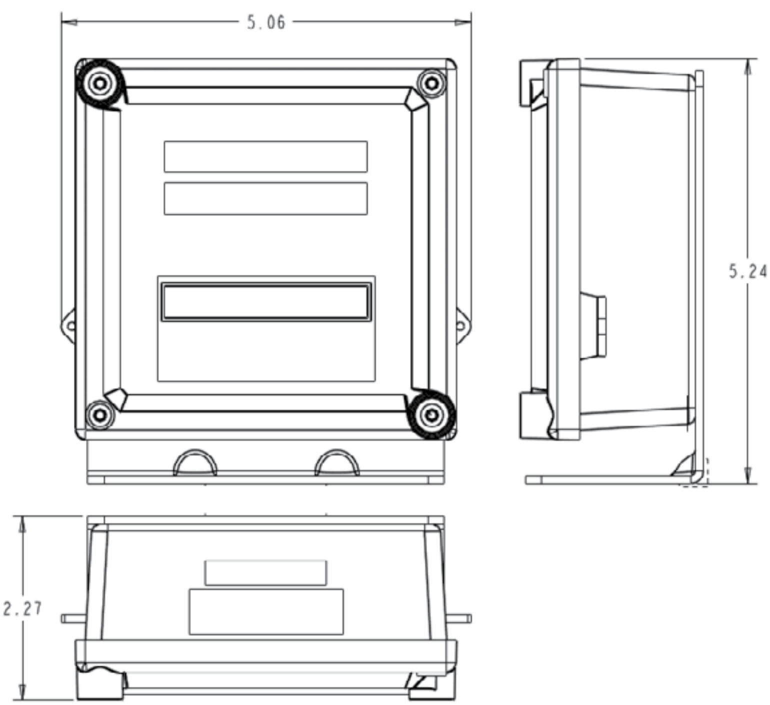
FEATURES & BENEFITS:
Why Landis+Gyr makes a difference.

- Leverages full potential and scalability of Gridstream AMI network
- Supports one generic collector alarm
- Variety of event settings available to inform of issues, such as low battery and tamper
- Serial Modbus Interface directly to Corrector
- Provides four dynamic channels of data to HES
- Configurable channels monitor Pressures, Temperature, Voltages, Corrected Volume and Uncorrected Volumes from supported devices
- Pressure Max and Min thresholds supported at the Head End System

Specifications

Power Supply	Four "A" lithium manganese dioxide batteries
	20-year battery life
Modulation Type	FSK modulation
Operating Temperature Range	-40ºC to +85ºC
Environmental	Relative humidity 0% to 100%
RF Standards	FCC Part 15.247
	Frequency: 902-928 MHz
	Baud Rate: 9600 to 38400 BPS
ANSI Standards	B109.1-2000 Compliance
	B109.2-2000 Compliance
Enclosure Rating	NEMA 3R
UL	UL – Class 1, Division 1, Group D
GPR-PT Events Included	Tilt switch
	Sensor failure
	Low battery
	Stale register
	Extreme temperature change
	Configuration change
	Cut lead detect

GPR-PT



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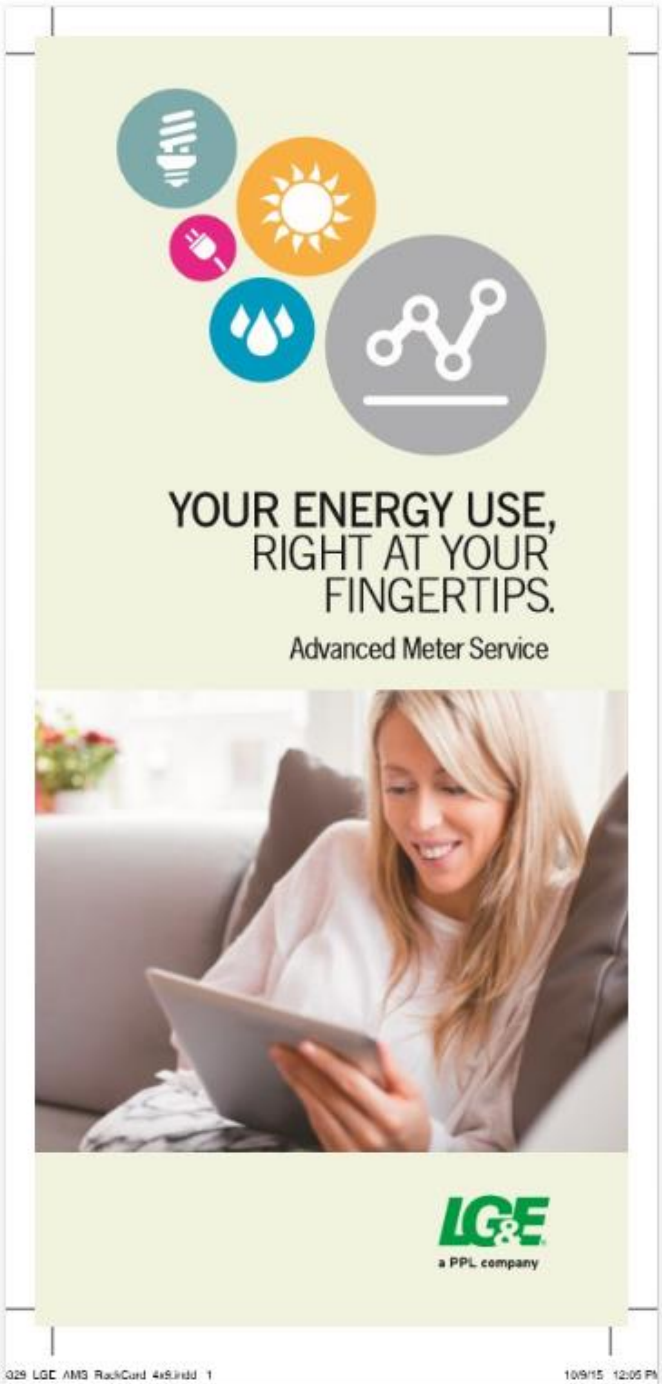
Appendix A-4

DSM AMS Customer Communications Examples

RACK CARDS

Front – LG&E

Microsoft Word Web App



Back – LG&E

SIGN UP TO TRACK AND MANAGE YOUR ENERGY USE MORE PRECISELY.

Our new Advanced Meter Service puts the power to control personal energy use in your hands. When you enroll, we'll exchange your home or small business electric meter with an advanced meter. Once your new meter's installed, you can use your MyMeter dashboard to:

- Track daily, weekly, monthly or yearly energy usage.
- Compare your energy use from season to season, or before, during, and after efficiency improvements.
- Set energy-saving reminders for things like changing furnace air filters or light bulbs.
- Customize your dashboard profile with relevant information about your home or business – building size, the type of appliances you have, improvements that could make a difference in your energy use, etc.

The Advanced Meter Service is a voluntary service available to residential and small commercial customers at no additional cost. Just log in to My Account at **lge-ku.com** to learn more and enroll today.

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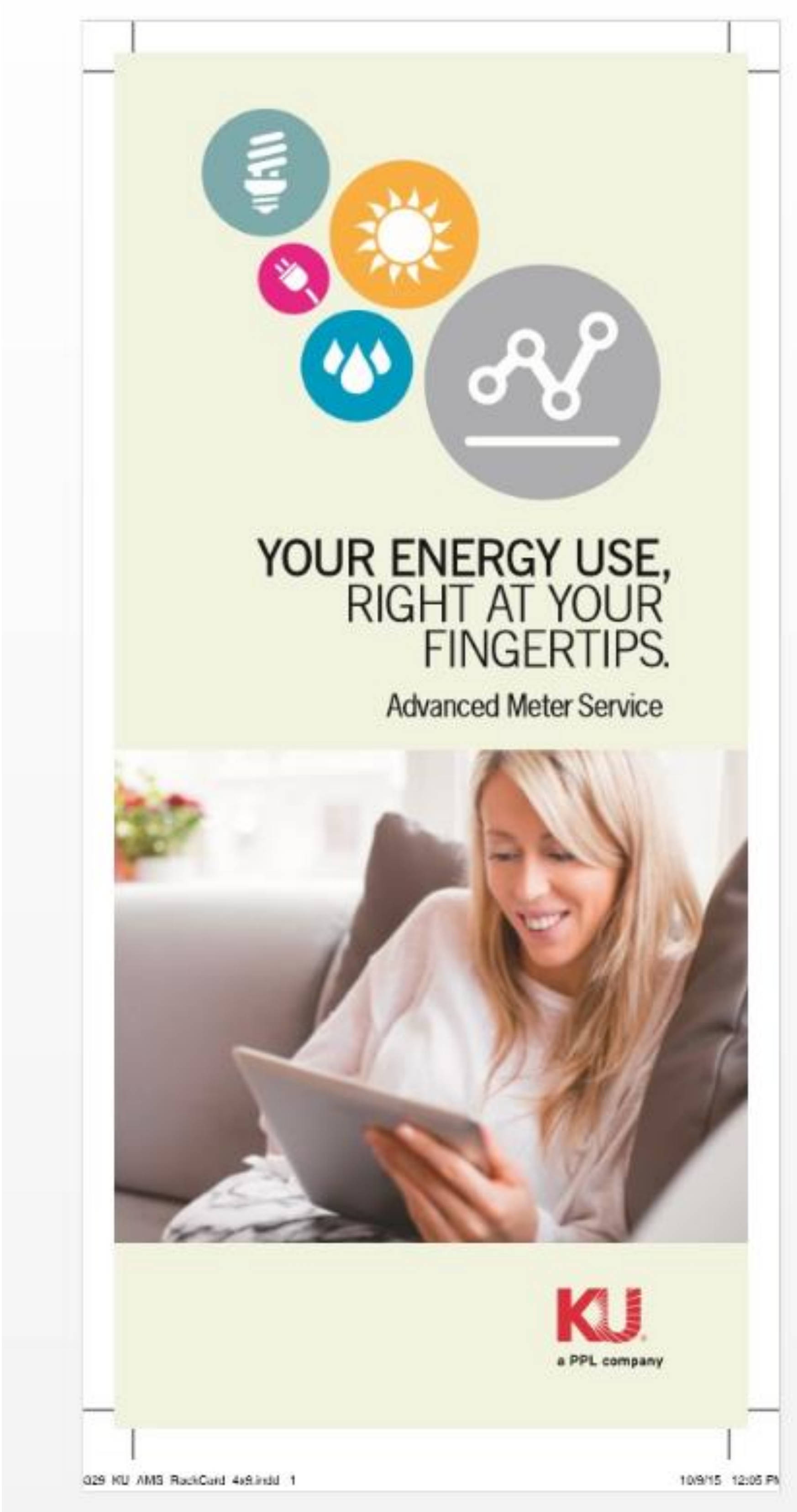
Front - KU


YOUR ENERGY USE,
RIGHT AT YOUR
FINGERTIPS.
Advanced Meter Service
KU
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029 KU AMS RackCard 4x9.indd 1
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SIGN UP TO TRACK AND MANAGE YOUR ENERGY USE MORE PRECISELY.

Our new Advanced Meter Service puts the power to control personal energy use in your hands. When you enroll, we'll exchange your home or small business electric meter with an advanced meter. Once your new meter's installed, you can use your MyMeter dashboard to:

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- Compare your energy use from season to season, or before, during, and after efficiency improvements.
- Set energy-saving reminders for things like changing furnace air filters or light bulbs.
- Customize your dashboard profile with relevant information about your home or business – building size, the type of appliances you have, improvements that could make a difference in your energy use, etc.

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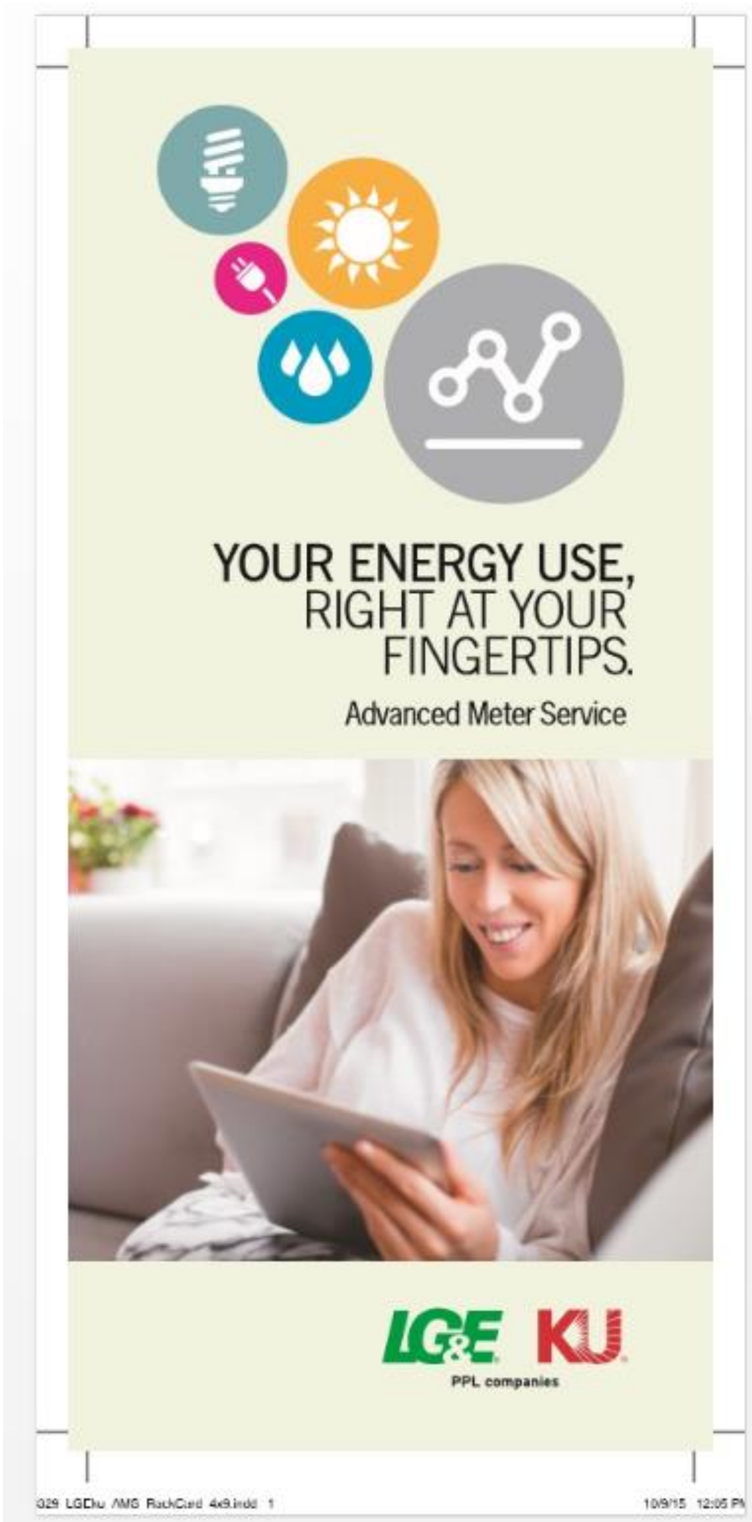
Front – LG&E and KU Version



Back – LG&E and KU Version

SIGN UP TO TRACK AND MANAGE YOUR ENERGY USE MORE PRECISELY.

Our new Advanced Meter Service puts the power to control personal energy use in your hands. When you enroll, we'll exchange your home or small business electric meter with an advanced meter. Once your new meter's installed, you can use your MyMeter dashboard to:

- Track daily, weekly, monthly or yearly energy usage.
- Compare your energy use from season to season, or before, during, and after efficiency improvements.
- Set energy-saving reminders for things like changing furnace air filters or light bulbs.
- Customize your dashboard profile with relevant information about your home or business – building size, the type of appliances you have, improvements that could make a difference in your energy use, etc.

The Advanced Meter Service is a voluntary service available to residential and small commercial customers at no additional cost. Just log in to My Account at **lge-ku.com** to learn more and enroll today.

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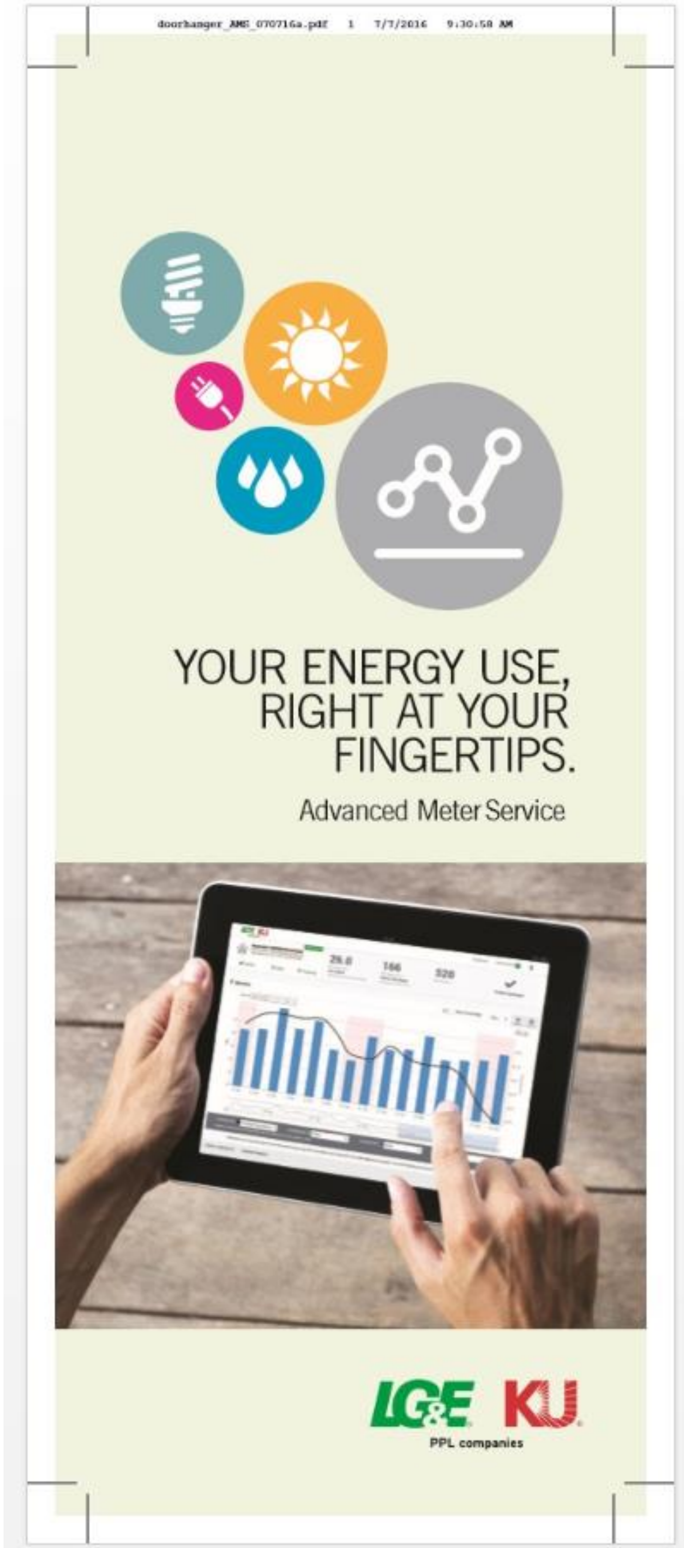
DOOR HANGER - FRONT



DOOR HANGER - BACK

doorhanger_AMS_070716a.pdf 2 7/7/2016 9:30:58 AM

SIGN UP TO TRACK AND MANAGE YOUR ENERGY USE MORE PRECISELY.

Our new Advanced Meter Service puts the power to control personal energy use in your hands. When you enroll, we'll exchange your home or small business electric meter with an advanced meter. Once your new meter's installed, you can use your MyMeter dashboard to:

- Track daily, weekly, monthly or yearly energy usage.
- Compare your energy use from season to season, or before, during, and after efficiency improvements.
- Set energy-saving reminders for things like changing furnace air filters or light bulbs.
- Customize your dashboard profile with relevant information about your home or business — building size, the type of appliances you have, improvements that could make a difference in your energy use, etc.

The Advanced Meter Service is a voluntary service available to residential and small commercial customers at no additional cost. Just log in to My Account at **lge-ku.com** to learn more and enroll today.

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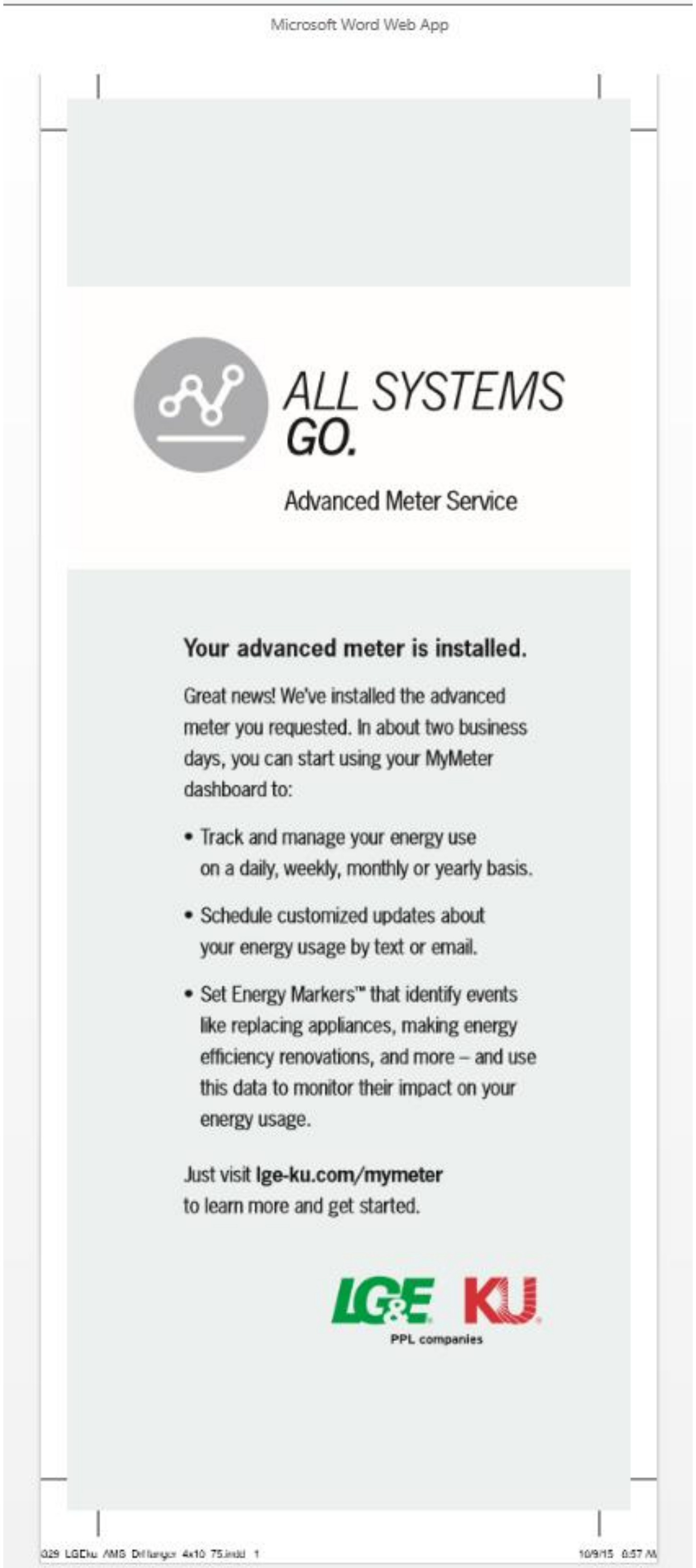
DOOR HANGER


Microsoft Word Web App
ALL SYSTEMS GO.
Advanced Meter Service
Your advanced meter is installed.
Great news! We've installed the advanced meter you requested. In about two business days, you can start using your MyMeter dashboard to:
• Track and manage your energy use on a daily, weekly, monthly or yearly basis.
• Schedule customized updates about your energy usage by text or email.
• Set Energy Markers™ that identify events like replacing appliances, making energy efficiency renovations, and more – and use this data to monitor their impact on your energy usage.
Just visit lge-ku.com/mymeter to learn more and get started.
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<u>EMAIL BLASTS</u>

July 2017

KU's Advanced Meter Service puts the power to control your personal energy use in your hands.

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a PPL company

Your Energy Use, Right at your Fingertips

KU's Advanced Meter Service puts the power to control your personal energy use in your hands. When you opt in to AMS, you can:

- Track your usage.
- Compare your current and previous usage patterns.
- Set reminders to change or clean your furnace filter or make other improvements.
- Receive notifications when your usage is approaching preset levels.
- Customize your energy dashboard.

Be an early adopter.

Enroll now

Questions?

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LG&E and KU Energy LLC I 220 West Main Street I Louisville, Ky 40202

August 2017

LG&E's Advanced Meter Service puts the power to control your personal energy use in your hands.

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Your Energy Use, Right at your Fingertips

LG&E's Advanced Meter Service puts the power to control your personal energy use in your hands. When you opt in to AMS, you can:

- Track your usage.
- Compare your current and previous usage patterns.
- Set reminders to change or clean your furnace filter or make other improvements.
- Receive notifications when your usage is approaching preset levels.
- Customize your energy dashboard.

Be an early adopter.

Enroll now

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November 2017 (Residential – LG&E)

Want more control over your energy usage? It's at your fingertips.

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Want more control over your energy usage? It's at your fingertips.

When you sign up for our Advanced Meter Early Adoption program, you'll have online access to your usage information. Want to know when you're using the most energy? How about when your energy usage reaches a certain point?

With an advanced meter, you'll be able to know all that and more. Use the ***charts*** and ***graphs*** in your online MyMeter dashboard – which you can access from your mobile phone, tablet or computer – to compare changes in your energy usage from the previous week, month or 90-day average.

More detailed information could mean more savings! Why wait?

Enroll now.

Learn more about LG&E's Advanced Meter Early Adoption Program.

Questions?

We're happy to help. Please contact Customer Service at lge-ku.com/contact. If you prefer to contact us by telephone, our representatives are available Monday through Friday.

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800-331-7370	800-331-7370

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November 2017 (Residential – KU)

Want more control over your energy usage? It's at your fingertips.

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Want more control over your energy usage? It's at your fingertips.

When you sign up for our Advanced Meter Early Adoption program, you'll have online access to your usage information. Want to know when you're using the most energy? How about when your energy usage reaches a certain point?

With an advanced meter, you'll be able to know all that and more. Use the ***charts*** and ***graphs*** in your online MyMeter dashboard – which you can access from your mobile phone, tablet or computer – to compare changes in your energy usage from the previous week, month or 90-day average.

More detailed information could mean more savings! Why wait?

Enroll now.

Learn more about KU's Advanced Meter Early Adoption Program.

Questions?

We're happy to help. Please contact Customer Service at lge-ku.com/contact. If you prefer to contact us by telephone, our representatives are available Monday through Friday.

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LG&E and KU Energy LLC I 220 West Main Street I Louisville, Ky 40202

November 2017 (Commercial – LG&E)

Want more control over your energy usage? It's at your fingertips.

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When you sign up for our Advanced Meter Early Adoption program, you'll have online access to your usage information. Want to know when your business is using the most energy or when your usage reaches a certain point?

With an advanced meter, you'll be able to know all that and more.

Use the ***charts*** and ***graphs*** in your online MyMeter dashboard – which you can access any time day or night – to compare changes in your energy usage from the previous week, month or 90-day average.

It doesn't matter if your business is open weekdays from 9 to 5 or 24/7/365. You can take steps to save energy. More detailed information could mean more savings! Why wait?

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Advanced Thinking:
More detailed info could mean more savings!

KU's Early Adoption Advanced Meter Service provides more information about your energy usage, including when you're using the most energy. This detailed information can help you better understand the factors that impact your energy bill.

What is an advanced meter?

Advanced meters give you **more timely information** on your energy use. After installation, you can access a customized online dashboard that can help **track and compare your energy usage** by day, week, month or year.

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a PPL company

BILL INSERT (KU – BACK)

While most meters record a running total of the amount of energy used, **an advanced meter can record energy usage data in 15-minute increments**. The meter will communicate the usage information to KU's data network system several times a day. And customers can set thresholds to be **notified when their energy usage reaches a certain point**.

That knowledge lets customers know more specifically when they are using energy, which can help them enact energy-efficiency measures to reduce usage and lower costs.

With an advanced meter, **all customer information is confidential**.

Be an early adopter

There is no additional cost to upgrade to an advanced meter. The Advanced Meter Early Adoption Program is only available to the first combined 5,000 KU residential electric and small commercial customers who sign up. **To enroll**, sign in to your online account today, or create one, at **my.lge-ku.com**.

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Advanced Thinking:
More detailed info could mean more savings!

LG&E's Early Adoption Advanced Meter Program provides more information about your energy usage, including when you're using the most energy. This detailed information can help you better understand the factors that impact your energy bill.

What is an advanced meter?

Advanced meters give you **more timely information** on your energy use. After installation, you can access a customized online dashboard that can help **track and compare your energy usage** by day, week, month or year.

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a PPL company

BILL INSERT (LG&E – BACK)

While most meters record a running total of the amount of energy used, **an advanced meter can record energy usage data in 15-minute increments**. The meter will communicate the usage information to LG&E's data network system several times a day. And customers can set thresholds to be **notified when their energy usage reaches a certain point**.

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Envelope Messages

Advanced Thinking – More detailed info could mean more savings.

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Be an Early Adopter! This program is available to the first combined 5,000 LG&E and 5,000 KU residential electric (RS rate) and small commercial (GS rate) customers who sign up for the program.

KU's Early Adopter Advanced Meter Service
provides more information about your energy usage, such as when you're using the most energy. This detailed information can help you better understand your monthly energy bill.

Visit **lge-ku.com** to request an advanced meter and find ways to save energy in your home.

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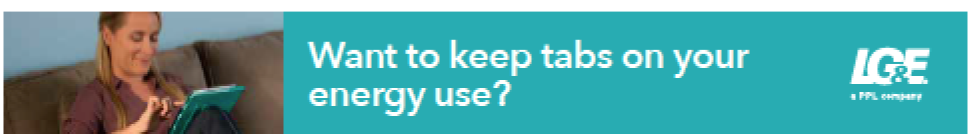
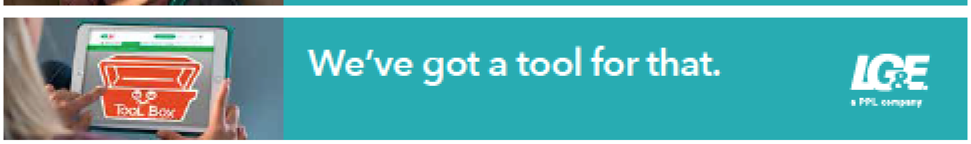
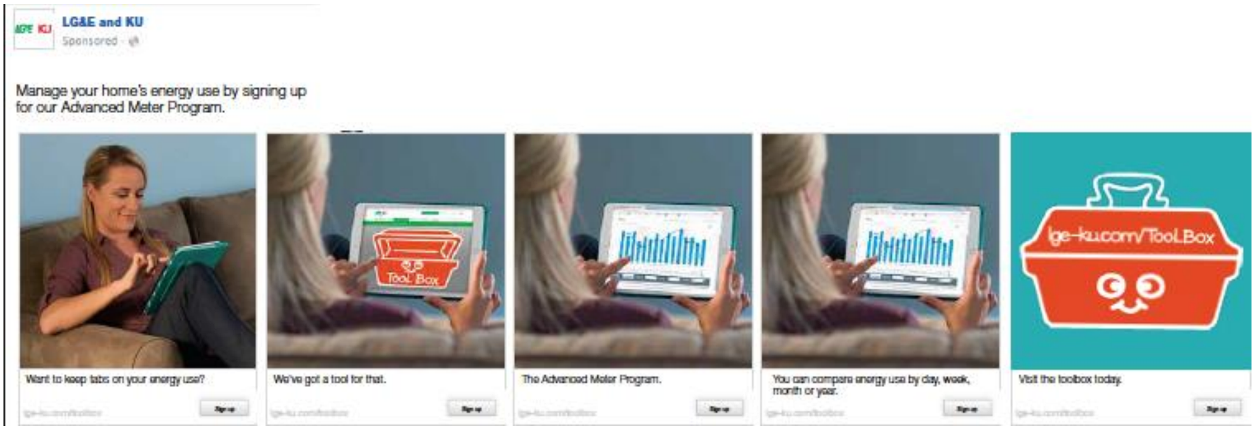
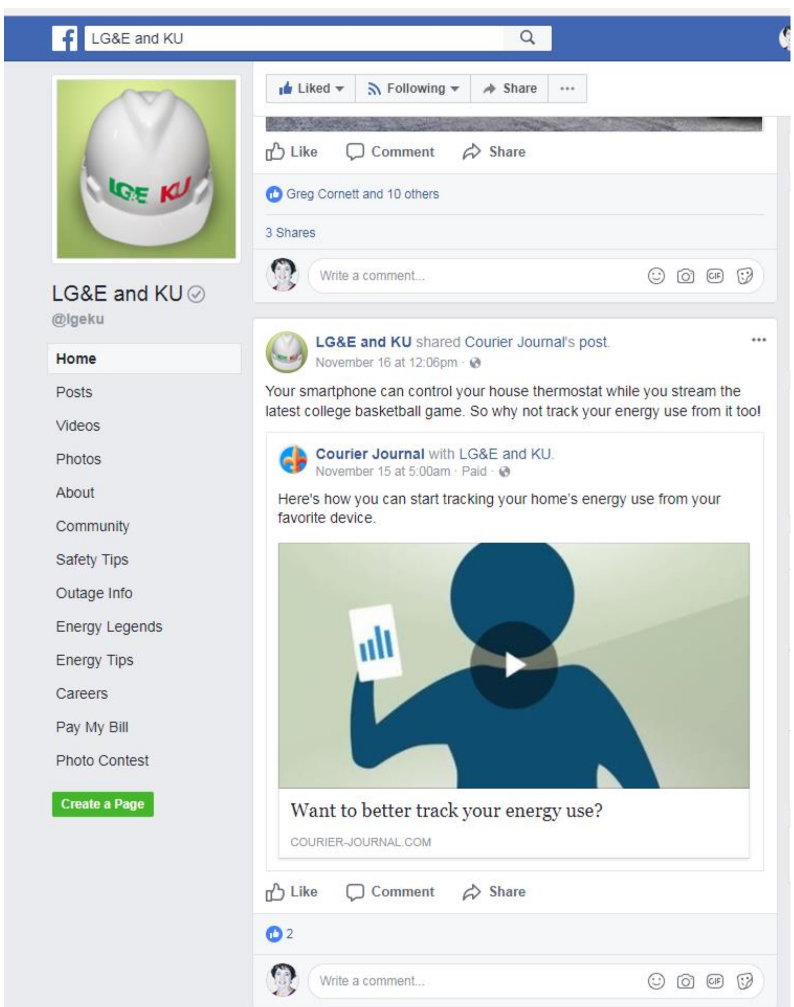




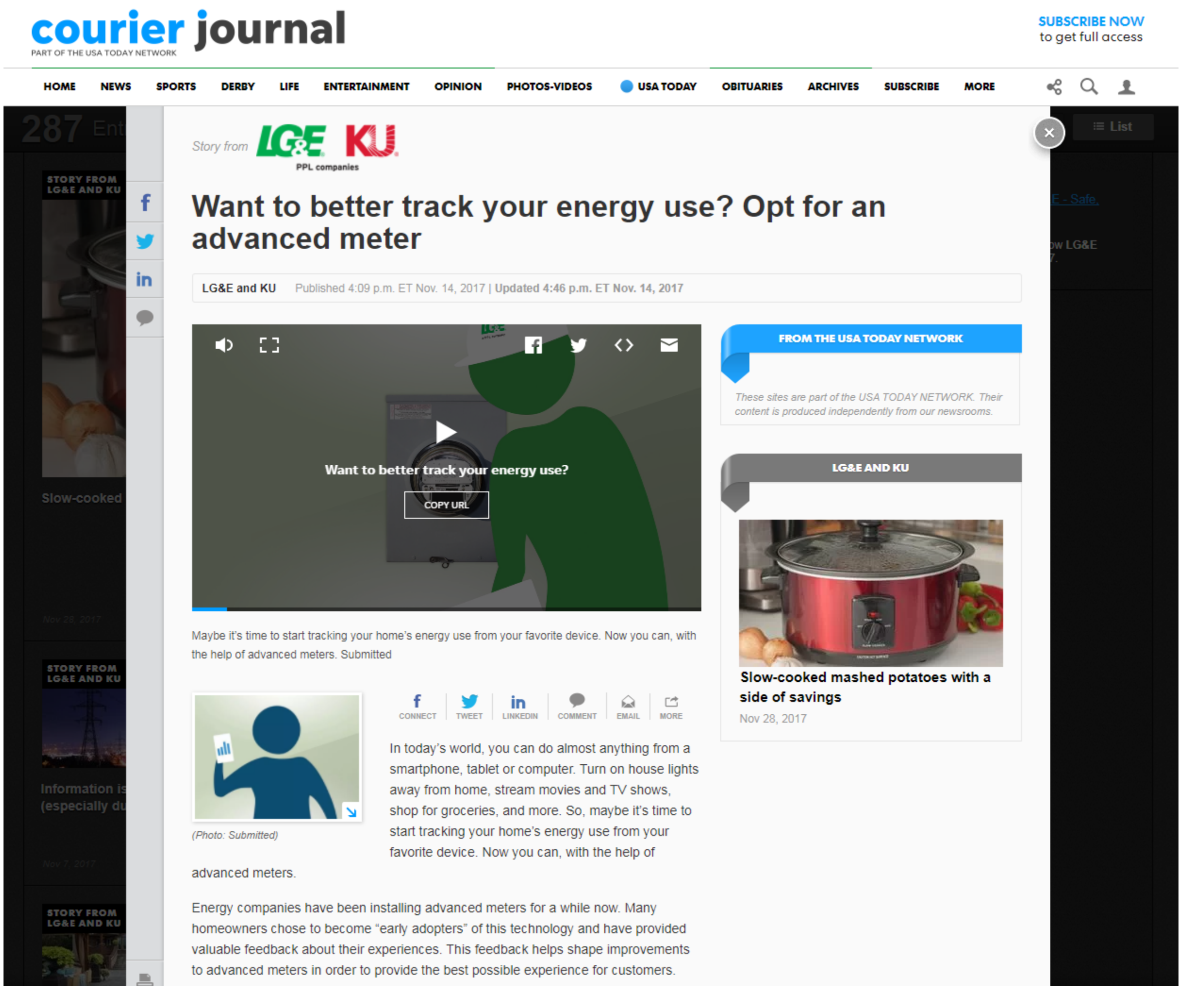
Facebook Ads



Social Media Posts



Courier-Journal Energy Matters (Native Advertising)



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Story from LG&E KU PPL companies

Want to better track your energy use? Opt for an advanced meter

LG&E and KU Published 4:09 p.m. ET Nov. 14, 2017 | Updated 4:46 p.m. ET Nov. 14, 2017

Want to better track your energy use?
COPY URL

Maybe it's time to start tracking your home's energy use from your favorite device. Now you can, with the help of advanced meters. Submitted

(Photo: Submitted)

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In today's world, you can do almost anything from a smartphone, tablet or computer. Turn on house lights away from home, stream movies and TV shows, shop for groceries, and more. So, maybe it's time to start tracking your home's energy use from your favorite device. Now you can, with the help of advanced meters.

Energy companies have been installing advanced meters for a while now. Many homeowners chose to become "early adopters" of this technology and have provided valuable feedback about their experiences. This feedback helps shape improvements to advanced meters in order to provide the best possible experience for customers.

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LG&E AND KU

Slow-cooked mashed potatoes with a side of savings
Nov 28, 2017

Videos

LG&E 15-second: https://www.youtube.com/watch?v=QUaE3xfV_7w

LG&E with FAQs: https://www.youtube.com/watch?v=bMZug13VlpA

KU 15-second: https://youtu.be/NmdL1YXYjD8

KU with FAQs: https://youtu.be/hzrLpXD_oIs

Appendix A-5

AMS Business Case Summary Presentation

AMS Business Case

LG&E KU
PPL companies

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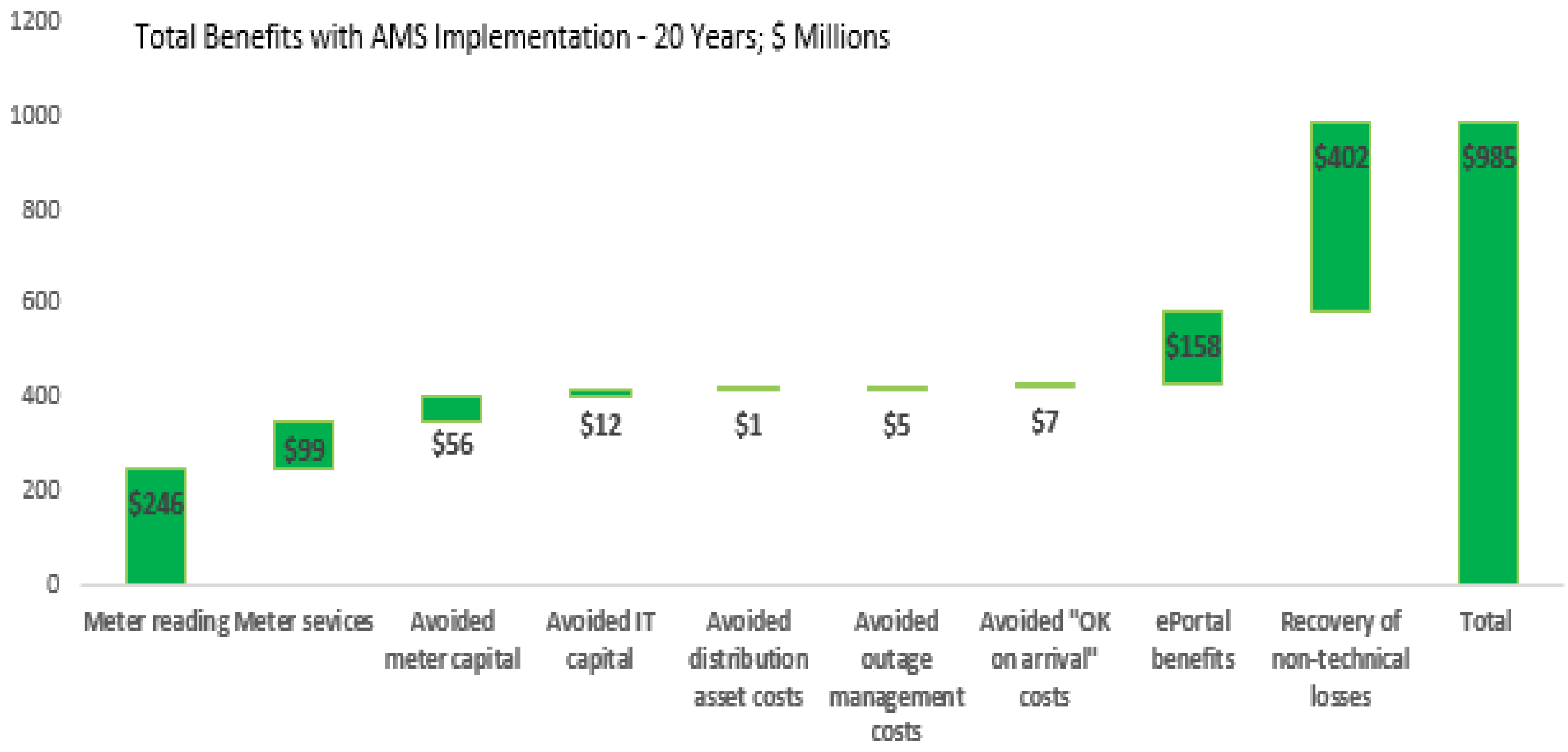
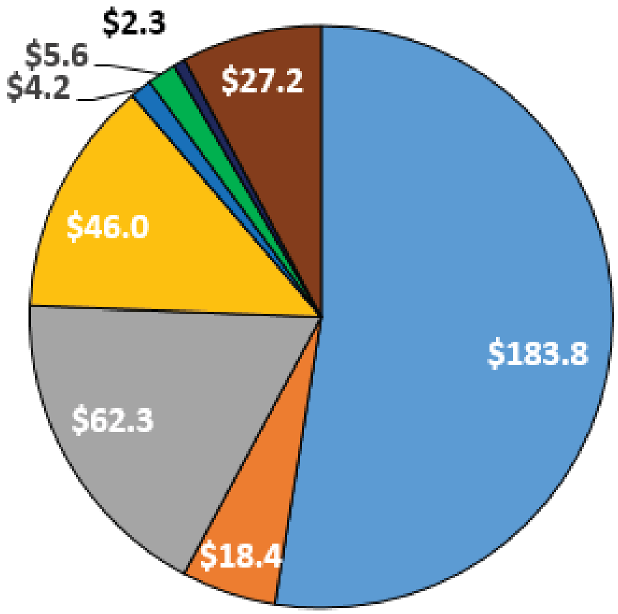
Total savings of nearly $1020 Million are possible over 20 years



Gross AMS implementation costs are ~$350 Million for 2018 – 2022



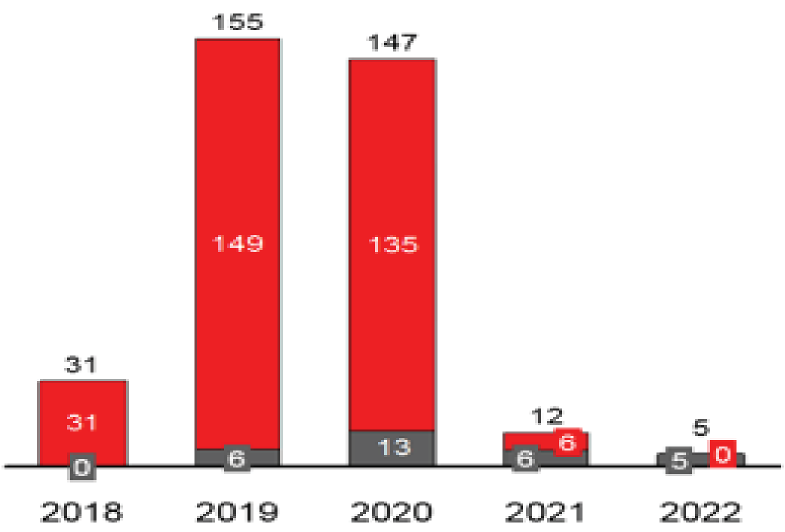
	Category	Capital	O&M	Total Nominal
	Meters	$171.1	$12.7	**$183.8**
	Network	$16.8	$1.6	**$18.4**
	Information Technology	$52.1	$10.2	**$62.3**
	Systems Integration	$46.0	$0.0	**$46.0**
	Program Management	$4.2	$0.0	**$4.2**
	Communications	$1.2	$4.4	**$5.6**
	Change Management	$1.4	$0.9	**$2.3**
	Contingency	$27.2	$0.0	**$27.2**
	Total	**$320.0M**	**$29.8M**	**$349.8M**

Capital expenditures account for 91% of the costs, and the bulk of the spend falls in years 2017-2019

Capex vs. Opex Cost 2018 – 2022 (in $ Millions)

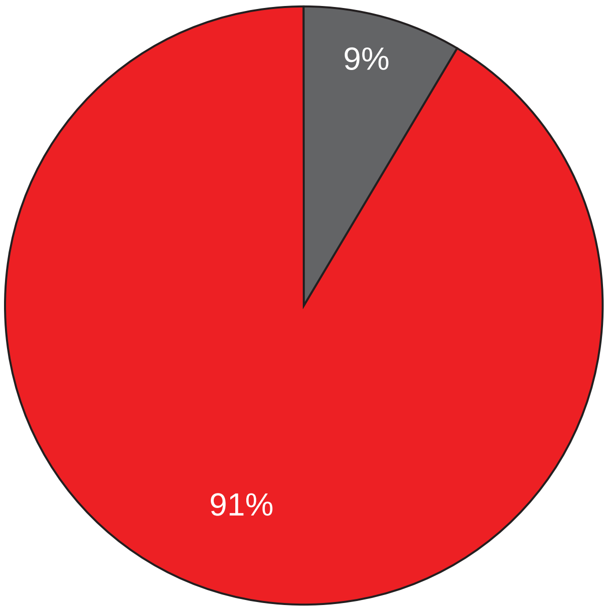
Capex = $320.0 Million

Opex = $29.8 Million



Capex Opex

100% = $349.8 Million



AMS will provide additional “qualitative” customer benefits

There are a number of additional customer benefits from AMS implementation that are not quantified in this analysis. AMS will enable new offerings for customers, improve customer satisfaction through access to data and better engagement with customers. AMS will:

Customer Offerings

- Support customer’s decision on optional rates through more granular data to calculate the savings and costs of different rates
- Provide a platform for future product and service offerings such as energy management, smart thermostats and appliances
- Enable the integration of DER, e.g., solar and electric vehicles to the grid
- Better assure costs are recovered equitably through data analytics and 2 way communication with the meter in detecting losses early
- Provide an avenue for Green Button initiatives
- Provide customer outage notification which can improve customer’s ability to monitor home while away

Customer Operations

- Improve first call resolution through access to customer data
- Support long-term DSM in DLC programs and VVO

Customer Outage / Power Quality Benefits

- Save cost of unserved energy due to reduced restoration time
- Enable better outage management and communications with the customer
- Improve power quality due to further development of the ability to monitor and analyze momentary outage and voltage issues

Environmental Benefits

- Reduce GHG emissions through reduction in power produced due to improved system losses, and provide a foundation for GHG state or federal plans

Table of Contents

Meter Reading and Meter Services Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
Meter Reading	• Currently in the LG&E, KU & ODP territories manual meter reading is performed by contractors on a revolving monthly basis. • AMS eliminates the need for manual meter reading after the MDMS is integrated in 2020 & meters are fully deployed in 2021	• Contractors perform meter reads monthly in the LG&E territory at $0.42/read, and in the KU and ODP territories at $0.70/read. • Assumed a cost escalation factor of 2.2% • Assumed no inspection variance is allowed and 14 PSC inspector are included	Total number of AMS meters * yearly contract value per meter * escalation factor * number of recovery years once MDMS is implemented – the annual cost of the inspectors	AMS 20 yr. savings **$203 Million**
Meter Services	• AMS will largely eliminate the need for technician to perform disconnection services. • Eliminating disconnection services, employee OT will be reduced • Additionally, by geographic area contractor positions will be eliminated while maintaining a sufficient workforce presence • Finally, the material budget will be cut as AMS eliminates the need for manual disconnections	• Reduced Employee OT at LG&E by 50% starting in 2019 • Reduced Employee OT at KU by 33% in 2019 and by 50% starting in 2020 • Contractor budget for LG&E will be reduced to 4 techs starting in 2019 • Contractor Budget for KU will be reduced to 17 techs in 2019 and 7 techs starting in 2020 • Reduced Purchased Materials by: '18: 0%, '19: 10%, '20: 20%, '21: 20%.	Utilizing the five-year budget define contractor spend, employee OT spend and material spend by year. For the five-year projection used the defined cuts to project savings. Take the 5th year budget savings and project it out with an escalation factor to the end of the recovery period	The meter services technician force is reduced due to AMS digitalizing the process along with the need for OT AMS 20 yr. savings **$92 Million**

1) Lifetime savings assume 2.2% escalation over lifetime

Avoided / Deferred Capital Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
IT	• The IT budget was evaluated for categories of spend that could be avoided or deferred base on the AMS implementation timeline and existing programs it would replace. • It should be noted the savings is considered avoided capital for all but one IT category (SAP CRM/ECC Enhancement)	• Based on the AMS implementation timeline, staffing levels, projected budgets, company priorities, and eliminating programs associated with manual meter reading, along with other factors, IT spend categories were evaluated.	• IT budget evaluation assuming that for deferred capital, the projected budget was steady-state	AMS 20 yr. savings **$11.8 Million**
Avoided Meter Capital	• The meter capital budget was evaluated for potential savings as the AMS program is implemented. • As a part of AMS implementation, meter inventory will be built up.	• The AMS implementation timeline, projected budgets, company priorities, inventory levels and the different types of meters to be deployed as a part of the AMS program were evaluated to build the savings projections.		AMS 20 yr. savings **$55.6 Million**

1) Lifetime savings assume 2.2% escalation over lifetime

Avoided Distribution Asset Costs Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
Distribution Asset Costs	• A percentage of distribution transformer failures can be predicted and mitigated with AMS technology, using the AMS data for transformer load management. Accurate transformer loading data allows for asset replacement under a planned outage regime. This results in lower outage duration vs. emergency replacement, and a lower replacement budget. – In 2015 Distribution Transformer outages were responsible for 7,180,149 customer minutes of interruptions. The system SAIDI contribution is 7.4 minutes. There were ~6,000 transformer failures.	1) Savings of 45 min. per outage for a number of the transformer failures (due to equipment failure and avoided) from better prediction of transformer loadings and planned outage regime 1) Protected revenue from reduced outage restoration time	1) Savings of 45 min. per outage for planned replacements • Transformer failures = 6,000 • Number of transformer failures avoided = 250 • Average crew size = 2 • Average hourly loaded cost for crew = $65 pp 2) Protected revenue from reduced restoration time • # of customers in trans-former outages = 5 • Annual avg. energy consumption = 30 MWh • Average retail price = 0.10 $/kWh • Assumes 4% average electric retail escalation	1) 250 outages x 45 min. time reduction / 60 x 2 x 65 / hr. field labor * labor escalation • **$764 Thousand** 2) 250 outages x 5 customers x 2.57 kWh usage x 0.10 $/kWh * retail escalation • **$11.2 Thousand** AMS 20 yr. savings **$0.8 Million**

1) Lifetime savings assume 2.2% escalation over lifetime

Avoided Outage Restoration Costs Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
Outage Mgmt. Costs	• Reduce cost and impact of outages through ability to more rapidly characterize outage location, type (e.g. momentary vs. sustained), duration, restoration priority, and materials using data from AMS meters	1) 50% reduction in time spent identifying outage location on non-DA circuits (assume 20% of outage duration – CAIDI spent identifying outage location) 2) Protected revenue from reduced outage restoration time 3) Fleet O&M cost reduction from 10% reduction in miles driven responding to outages	1) Reduction in time spent identifying outage location • Outage duration (CAIDI) – Blue Sky = 96 mins. • Reduction in time spent = 9.6 mins. • # of Blue Sky outages = 20,000 • % non-DA circuits = 50% • Average crew size = 1 • Average hourly loaded cost for crew = $65 pp • Assumes 3% labor escalation 2) Protected revenue from reduced restoration time • # of customers in Blue Sky outages = 40 • Annual avg. energy consumption = 30 MWh • Average retail price = 0.10 $/kWh • Assumes 4% electric retail price escalation 3) Reduction in miles driven responding to outages • Average travel time per outage = 30 mins. Average mileage = 20 miles per outage • Reduction in miles driven = 2 miles • Cost per mile = - $1.46 • Assumes 2.2% non-labor escalation	1) 10,000 Blue Sky outages x 9.6 mins time reduction / 60 x 1 x 65 / hr. field labor x labor escalation • **$3.3 Million** 2) 10,000 Blue Sky outages x 40 customers x 0.55 kWh usage x 0.10 $/kWh x retail price escalation • **$0.5 Million** 3) 10,000 Blue Sky outages x 20 miles per outage x 10% reduction x $1.46/mile x retail price escalation • **$0.8 Million** AMS 20 yr. savings **$4.6 Million**

1) Lifetime savings assume 2.2% escalation over lifetime

Avoided "OK on Arrival" Truck Rolls Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
"OK on Arrival" Avoided Truck Roll Benefits	• Number of "OK on arrival" orders – where a crew is dispatched for a reported outage, but find that everything is working properly when they arrive, can be reduced with AMS. AMS meters provide the capability to "ping" a meter to determine whether the meter is communicating. Power is required at the meter in order for the meter to respond to the ping request. Therefore, LKE can use the meter ping to verify that a customer has service without sending a crew, thereby avoiding costs associated with unnecessary truck rolls. This results in crew time savings and fleet mileage savings	1) Truck roll savings for "OK on arrival" orders including ~1 hr. of crew time only	1) Savings of 1 hr. of crew time per truck roll ($65 per truck roll) • Number of "Ok on arrival" orders for single outage calls avoided = 3,400 • Cost of a truck roll = $65 per truck roll • Assumes 3% labor escalation	1) 3,400 "OK on arrival" orders avoided x $65 per truck roll x labor escalation • **$6.9 Million** AMS 20 yr. savings **$7.1 Million**

1) Lifetime savings assume 2.2% escalation over lifetime

ePortal Customer Benefits Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
ePortal Customer Benefits	• The web portal will give customers access to their electric usage data. This granular data, in combination with educational materials, will give customers insights into their electric energy usage and enable them to reduce it.	• Based on preliminary results of the pilot, LG&E/KU is experiencing 48% of electric customers use the portal at least once. • LG&E/KU estimates that 36% of those customers who have utilized the portal at least once identify value in the electric usage information provided and continue to use the portal to draw insights into their consumption patterns and adjust their behavior to save energy. • Based on a smart grid consumer collaborative report, between 2 to 5% reduction in usage is projected for active users. We have projected a 3 % energy savings for those customers actively using the portal.	Average monthly bill: • LG&E $82.46 • KU $117.79 • ODP $130.42 ~48% of customers use the portal at least once Of that 48%, approximately 36% will benefit from the energy granularity of AMS Average energy savings is 3% Removed 0.8% of in-scope customers to account for estimated opt-out.	($82.46/month or $117.79/month or $130.42) * 12 months * escalation factor * 48% * 36% * 3% • **$166 Million** AMS 20 Yr. Savings **$158.1 Million**

1) Lifetime savings assume 2.2% escalation over lifetime

Recovery of Non-Technical Losses / Theft Reduction Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings
Recovery of non-technical losses (Meter Integrity and Theft Reduction)	• Identify endpoints with usage anomalies and meter events that indicate potential intentional theft, meter configuration errors and meter malfunctions – E.g. – Intermittent outages coupled with usage reductions indicating physical meter breach or bypass (e.g. tilt, rotation, reverse flow) – Anomalous load profile (statistically significant variation) indicating meter disable or jumpering – Anomalies or meter events suggesting meter malfunction or configuration error (i.e. measurement errors, missing interval data)	1) Detect 60% of non-technical losses including theft and meter malfunctions through AMS analytics, and assume recovery of 60% of validated loss through back bill, correction, or disconnection	1) Detect 60% of non-technical line losses through AMS analytics and recover 60% of validated loss • Non-technical line losses = 2% of revenues • % of non-technical line losses detected by AMS Analytics = 60% • Recovery of non-technical line losses detected = 60% • 0.96% increase in revenues is applied to forecasted revenues for non-MV90 customers • Removed 0.8% of in-scope customers to account for estimated opt-out.	1) ~$2.2B revenues for non-MV90 customer * 0.72% increase in revenue • **$489 Million** AMS 20 yr. savings **$402.3 Million**

AMS Cost-Benefit Summary – nominal

Nominal Costs

	2018-2040
Total project costs – capital	$320.0M
Total project costs – O&M	$29.8M
Total project costs	**$349.8M**
Total recurring costs – capital	$43.8M
Total recurring costs – O&M	$108.9M
Total recurring costs	**$152.7M**
Meter Retirement	**$0.0M**
Total lifecycle costs	**$502.5M**

Nominal Benefits

	2018-2040
Operational benefits	$425.2M
ePortal benefits	$158.1M
Recovery of non-technical losses	$402.3M
Total project benefits	**$985.6M**
Total lifecycle benefits	**$985.6M**

Refined net lifecycle costs (-) / benefits (+) $483.1M (nominal)

Appendix A-6

AMS Capital Evaluation Models

Appendix A-6.1

CEM – Summary

Financial Summary for

AMS Full Deployment

Various Project Numbers

Advanced Metering System: Customer Services

Financial Analysis - Project Summary	RECOMMEND-ATION
Total Capital Expenditures Requested, $000s	$363,851
Total Cost Savings/(Incremental Costs), $000s	$846,780
NPV Revenue Requirements, $000s	($28,469)

	RECOMMENDATION						
Financial Analysis - By Year	5-Year Total 2018-2022	2018	2019	2020	2021	2022	Life 2018-2033
Capital Expenditures Requested, $000s	$320,035	$30,734	$148,656	$134,523	$6,122	$0	$363,851
Cost Savings/(Incremental Costs), $000s	$83,090	$2,218	$5,241	$9,853	$31,398	$34,381	$846,780

NPVRR general rules:

The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Appendix A-6.2

CEM – Network

Financial Summary for

AMS Full Deployment - Network

Project Number 155496
Advanced Metering System: Customer Services
Servco

Financial Analysis - Project Summary	RECOMMEND-ATION	Alternative #1	Alternative #2	Alternative #3
Total Capital Expenditures Requested, $000s	**$22,364**	$0	$0	$0
Total Cost Savings/(Incremental Costs), $000s	**$846,780**	$0	$0	$0
NPV Revenue Requirements, $000s	**($384,589)**	$0	$0	$0

	RECOMMENDATION						
Financial Analysis - By Year	**5-Year Total 2018-2022**	**2018**	**2019**	**2020**	**2021**	**2022**	**Life 2018-2033**
Capital Expenditures Requested, $000s	$18,509	$2,684	$15,192	$624	$10	$0	$22,364
Cost Savings/(Incremental Costs), $000s	$83,090	$2,218	$5,241	$9,853	$31,398	$34,381	$846,780

NPVRR general rules:

The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Appendix A-6.3

CEM – LG&E Meters

Financial Summary for

AMS Full Deployment - Meters - LG&E

Project Number 153931 & 153932

Advanced Metering System: Customer Services

LG&E

Financial Analysis - Project Summary	RECOMMEND-ATION	Alternative #1	Alternative #2	Alternative #3
Total Capital Expenditures Requested, $000s	**$107,775**	$0	$0	$0
Total Cost Savings/(Incremental Costs), $000s	**$0**	$0	$0	$0
NPV Revenue Requirements, $000s	**$115,719**	$0	$0	$0

	RECOMMENDATION						
Financial Analysis - By Year	5-Year Total 2018-2022	2018	2019	2020	2021	2022	Life 2018-2033
Capital Expenditures Requested, $000s	$100,206	$2,112	$48,311	$49,128	$655	$0	$107,775
Cost Savings/(Incremental Costs), $000s	$0	$0	$0	$0	$0	$0	$0

NPVRR general rules:

The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Appendix A-6.4

CEM – KU Meters

Financial Summary for

AMS Full Deployment - Meters - KU

Project Number 153933

Advanced Metering System: Customer Services

KU

Financial Analysis - Project Summary	**RECOMMEND-ATION**	**Alternative #1**	**Alternative #2**	**Alternative #3**
Total Capital Expenditures Requested, $000s	**$94,778**	$0	$0	$0
Total Cost Savings/(Incremental Costs), $000s	**$0**	$0	$0	$0
NPV Revenue Requirements, $000s	**$100,091**	$0	$0	$0

	RECOMMENDATION						
Financial Analysis - By Year	**5-Year Total 2018-2022**	**2018**	**2019**	**2020**	**2021**	**2022**	**Life 2018-2033**
Capital Expenditures Requested, $000s	$87,927	$2,422	$29,617	$52,691	$3,197	$0	$94,778
Cost Savings/(Incremental Costs), $000s	$0	$0	$0	$0	$0	$0	$0

NPVRR general rules:

The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Appendix A-6.5

CEM – IT Systems

Financial Summary for

AMS Full Deployment - IT Systems

Project Number 155483

Advanced Metering System: Customer Services

Servco

Financial Analysis - Project Summary	RECOMMEND-ATION	Alternative #1	Alternative #2	Alternative #3
Total Capital Expenditures Requested, $000s	**$138,934**	$0	$0	$0
Total Cost Savings/(Incremental Costs), $000s	**$0**	$0	$0	$0
NPV Revenue Requirements, $000s	**$140,309**	$0	$0	$0

	RECOMMENDATION						
Financial Analysis - By Year	**5-Year Total 2018-2022**	**2018**	**2019**	**2020**	**2021**	**2022**	**Life 2018-2026**
Capital Expenditures Requested, $000s	$113,392	$23,515	$55,535	$32,081	$2,261	$0	$138,934
Cost Savings/(Incremental Costs), $000s	$0	$0	$0	$0	$0	$0	$0

NPVRR general rules:

The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Appendix A-7

Smart Grid Economic and Environmental Benefits

Smart Grid Consumer Collaborative

Smart Grid Economic and Environmental Benefits

A Review and Synthesis of Research on Smart Grid Benefits and Costs

SmartGrid consumer collaborative

October 8, 2013

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FOREWORD

About This Review

Many researchers have forecast the likely costs and benefits of a Smart Grid using macroeconomic analysis. In 2011 the Electric Power Research Institute forecast that the cost to upgrade the U.S. grid to "smart" status would be between $338 billion and $476 billion, and would generate benefits of between $1,294 billion and $2,028 billion,[1] for an anticipated benefit-to-cost ratio of between 2.8 and 6.0 to 1. U.S. utility Smart Grid business cases typically forecast benefit-to-cost ratios of between 1.1 and 3.0 to 1.

Because real-world experience with the Smart Grid is growing, the Smart Grid Consumer Collaborative (SGCC) completed a review of available research quantifying the actual – rather than forecast – benefits and costs to help stakeholders analyze and maximize the value of various capabilities. This report summarizes available research in terms consumers can understand and synthesizes findings in a "per customer" context whenever possible.

Smart Grid planning and investment is undertaken in a complex environment with numerous stakeholders, including, among others:

- Consumer advocates
- Environmental advocates
- Regulators
- Consumers
- Legislators
- Utilities
- Hardware, software, and service suppliers to the utility industry

This review aims to help these stakeholders determine what U.S. consumers can realistically expect to receive relative to Smart Grid investment for their money based on demonstrated experience. It has been specifically developed to help stakeholders understand:

- Exactly how Smart Grid capabilities create value relative to a traditional grid
- The size of the various benefits (economic, reliability, environmental, and customer choice) as supported by available research, expressed "per customer per year" whenever possible
- The key drivers of these benefits
- The costs typically incurred to create those benefits, expressed "per customer" whenever possible

1 Electric Power Research Institute, Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid, March 2011, 1–4.

"Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers"

We have created "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," a separate guide detailing certain technical and economic concepts discussed in this review. The guide is available from the SGCC, and we encourage readers interested in additional details to consult the guide.

About the Smart Grid Consumer Collaborative

SGCC is a consumer-focused nonprofit organization formed to promote an understanding of the benefits of modernized electrical systems among all stakeholders in the United States. Membership is open to all consumer and environmental advocates, technology vendors, research scientists, and electric utilities for sharing research, best practices, and collaborative efforts of the group. Learn more at smartgridcc.org.

About the Wired Group

This research was conducted by the Wired Group, a consultancy helping clients unleash the latent value in distribution utility businesses. Learn more at wiredgroup.net.

Acknowledgements

The SGCC would like to thank the many individuals, companies, and organizations that helped formulate insights from the research reviewed and provided feedback on the content, themes, and layout of this review. Only by continuing to collaborate on consumer issues will we be able to fully realize the promise of Smart Grid. If you are not a member, we invite you to join us as we continue to listen, collaborate, and educate going forward.

October 8, 2013

Patty Durand, Executive Director
Smart Grid Consumer Collaborative

Smart Grid Consumer Collaborative Members

The following organizations support the Smart Grid Consumer Collaborative and its mission:

- Accenture
- ACEEE
- Aclara Technologies
- Alameda Municipal Power
- Alliance to Save Energy
- Ameren Illinois
- Arizona Public Service Company
- Association for Demand Response & Smart Grid
- Avista Utilities
- Baltimore Gas and Electric Company
- BC Hydro
- Benton PUD
- Bonneville Power Administration
- Brookhaven National Laboratory
- C3 Energy
- California Center for Sustainable Energy
- California Public Utilities Commission
- CenterPoint Energy
- Climate + Energy Project
- CNT Energy
- Cobb EMC
- Colorado Public Utilities Commission
- ComEd
- Comverge
- Consumers Energy
- CPS Energy
- DNV KEMA
- Dominion
- DTE Energy
- Duke Energy
- Duquesne Light Company
- Electric Power Research Institute
- Energy Providers Coalition for Education
- Environmental Defense Fund
- Fayetteville Public Works Commission
- FirstEnergy
- Florida Power & Light
- Future of Privacy Forum
- Gainesville Regional Utilities
- Galvin Electricity Initiative
- GE Energy
- Georgia Institute for Technology
- Green DMV
- The Greenlining Institute
- GridWise Alliance
- IBM
- Illinois Citizens Utility Board
- Institute for Energy & Environment at Vermont Law
- Idaho Falls Power
- Intelligent Energy Solutions LLC
- Itron
- Landis + Gyr
- Lawrence Berkeley National Laboratory
- Market Strategies International
- Michigan Public Service Commission
- Middle Tennessee EMC
- Minnesota Valley Electric Cooperative
- Montana State University
- National Institute of Standards and Technology
- National Renewable Energy Laboratory
- Natural Resources Defense Council
- NC Department of Commerce – Energy Office
- NETL – Smart Grid Implementation Task Force
- New Brunswick Power Corporation
- North Carolina Sustainable Energy Association
- Office of People's Counsel DC
- Office of the Ohio Consumers' Counsel
- Oklahoma Gas & Electric
- Oncor
- Opower
- Oracle
- Oregon Citizens Utility Board
- Pacific Gas and Electric Company
- Pacific Northwest National Laboratory
- PayGo
- Peak Load Management Alliance
- Pepco Holdings, Inc.
- Portland General Electric
- Power Systems Consultants, Inc.
- Public Utility Commission of Texas
- Research Triangle Cleantech Cluster
- Sempra Utilities / San Diego Gas & Electric
- Siemens AG
- Silver Spring Networks
- Simple Energy
- Smart Grid Oregon
- Southeast Energy Efficiency Alliance
- Southern California Edison
- Southern Company
- Southface Energy Institute
- Southwest Research Institute
- Stoel Rives LLP
- TechAmerica
- Tendril
- Tennessee Valley Authority
- Texas Office of Public Utility Counsel
- Tri-County Electric Cooperative
- TVPPA
- Utility Consumers' Action Network
- Vermont Energy Investment Corporation

1. EXECUTIVE SUMMARY

The SGCC completed this review to help stakeholders better understand the benefits – economic, environmental, reliability, and customer choice – associated with Smart Grid investments. We present controlled studies from actual Smart Grid deployments whenever possible, synthesizing research results into a "per customer per year" context using assumptions based on actual Smart Grid deployments. In order to reflect variability across different utility operating environments, we present a set of conservative assumptions that we refer to as the "Reference Case," along with more aggressive assumptions reflecting "the state of the possible" that we refer to as the "Ideal Case." We also describe the benefit drivers for each Smart Grid capability.

Findings

We believe readers of this report are likely to reach the conclusion that Smart Grid investments offer economic benefits in excess of costs, and likewise offer significant reductions in environmental impact.

Smart Grid Investment Offers Economic Benefits in Excess of Costs

The Smart Grid appears to offer both direct benefits (those which could affect consumers' bills) and indirect economic benefits to customers. Direct benefits are delivered through four primary mechanisms:

- Increasing electric distribution efficiency, primarily through Integrated Volt/VAr Control (IVVC).
- Facilitating changes in customer behavior, either by shifting usage away from high-demand periods or by reducing usage. These capabilities include offering customers more choices including time-varying rates, prepayment programs, and customer energy management systems.
- Reducing operating costs from capabilities such as remote meter reading and remote service disconnect/reconnect.
- Improving revenue capture through improved Smart Meter accuracy and theft detection capabilities.

The Smart Grid also appears to offer significant indirect benefits to communities through economic productivity increases associated with improved grid reliability. Capabilities such as fault location help repair crews find faults faster, while fault isolation limits the number of customers impacted by any particular service outage.

Smart Grid Investment Offers Significant Reductions in Environmental Impact

The Smart Grid offers significant reductions in environmental impact through two sources: conservation and greater renewable generation integration. Greenhouse gas[2] emission reductions can be traced directly to Smart Grid capabilities – such as time-varying rates and customer energy management systems – offering a conservation effect. We find that the Smart Grid increases the level of customer-sited generation that the distribution grid can reliably and efficiently accommodate. To the extent this generation is renewable, Smart Grid capabilities designed to accommodate it offer even more significant environmental benefits.

Direct and Indirect Benefits by Capability per Customer per Year

Reference Case and Ideal Case Benefits

Table 1 summarizes the available benefits from various Smart Grid capabilities found in the research. In many cases, we have made assumptions about key benefit drivers such as customer participation rates to convert the research findings into a "per customer per year" metric. Where a range is presented, the low end represents the Reference Case, which embodies assumptions typical of the current average capability deployment. The high end represents the Ideal Case, which is based on assumptions that, though the research indicates are achievable, may not be reached unless the benefit drivers are carefully and thoughtfully optimized by Smart Grid stakeholders.

Not all Smart Grid capabilities are subject to large variation. For example, capabilities designed to improve reliability are not driven by customer participation rates. In other cases, insufficient research for a particular capability is available on which to base differences between a Reference Case and Ideal Case, rendering any such distinctions arbitrary. A summary of Reference Case and Ideal Case assumptions is presented in the appendices. Sources are footnoted throughout this review.

Direct and Indirect Benefits

Direct benefits are those that could affect customers' bills, whereas the indirect benefit calculations represent our attempt to translate reliability and environmental performance improvements from Smart Grid capabilities into economic terms.

2 Referred to throughout this report as "carbon dioxide equivalent emissions," "CO_2 equivalent," or "CO_2e" emissions.

Table 1. Benefits by Smart Grid capability per customer per year

Capability	Direct Economic Benefits	Reliability Improvement	CO_2 Equivalent Reduction[3]	Indirect Economic Benefits[4]	Customer Choice Benefits
Integrated Volt/ VAr Control	$11.24–32.01	Improved power quality (value not quantified)	Likely – 372 lbs.	Likely – $2.59	
Remote Meter Reading	$13.68–23.92		Possible	Possible	
Time-Varying Rates	$2.00–19.98		11–110 lbs.	$0.08–0.76	Yes
Prepayment and Remote Dis-/ Reconnect	$7.82–19.56		30–76 lbs.	$0.21-0.53	Yes
Revenue Assurance	$3.00				
Customer Energy Mgmt.	$0.77–1.92		14–34 lbs.	$0.10–0.24	Yes
Service Outage Management	$1.18	4.5% 4.9 minutes		$8.82	
Fault Location and Isolation		20.5% 22.3 minutes		$40.14	
Renewable Generation Integration	Possible	Likely	Likely		Yes
TOTALS	$39.69–101.57	25% 27.2 minutes	55–592 lbs.	$49.35-53.08	Yes

It is important to note that no single utility necessarily has all of these capabilities and each utility's results could vary significantly from these estimates. The most significant drivers of benefits and opportunities for improvement are described for each capability in this review.

3 Carbon dioxide reductions are estimated at 1.22 lbs. per kWh, per U.S. Environmental Protection Agency, "eGRID 2012 Subregion GHG Output Emission Rates for Year 2009." Table 1, column = Total Output Emissions Rate (lb/MWh), April 2012. http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf.

4 The value of carbon emissions reductions is estimated at $14.00 per metric ton (the price for a CO_2 emissions permit in the May, 2013 California auction). The value of an avoided minute of service outage is estimated at $1.80 based on a recent Lawrence Berkeley National Laboratory study; see "Estimating the Economic Productivity Impact of Service Outages" in the appendices for more information.

Benefit Drivers

Our analysis indicates that four drivers explain most of the variation in the available benefits.

Table 2. Drivers of Smart Grid capability benefits

Capability	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Integrated Volt/VAr Control	X			X
Remote Meter Reading	X		X	
Time-Varying Rates		X		X
Prepayment and Remote Dis-/ Reconnect	X	X		X
Revenue Assurance				X
Customer Energy Management		X		X
Service Outage Management	X			
Fault Location and Isolation	X			
Renewable Generation Integration	X	X		X

There appear to be some opportunities available to increase the benefits of Smart Grid capabilities through policy. As one example, traditional ratemaking practices may not encourage utilities to reduce sales volumes between rate cases. Once electric rates are set in a rate case, reductions in sales volume below anticipated levels reduce the likelihood that a utility will be able to cover its costs. Several Smart Grid capabilities discussed in this review, including Integrated Volt/VAr Control and time-varying rates, derive a significant proportion of available economic benefits via reductions in sales volumes. Other regulatory rules and norms may require revisions to enable some customer economic benefits, for instance billing and payment program innovations. The SGCC hopes this review will help stakeholders work together in pursuit of policy solutions that enable customer equity, provide customers with choices, and encourage utility investment, while maximizing available benefits for all customers.

Costs by Smart Grid Component

The average Smart Grid cost per customer, based on budget information from U.S. utilities' applications for the U.S. Department of Energy's Smart Grid Investment Grant (SGIG) program funds, is presented in Table 3 by component.

Table 3. Average cost per customer by Smart Grid component

Smart Grid Component	Sample Size	Average Cost per Customer
Smart Meter	24 projects	$291.54
Distribution Automation	12 projects	$63.64

In addition to these costs, we assume utilities will make annual expenditures equal to 4 percent of initial Smart Grid investments to operate and maintain hardware, software, and communications networks.[5]

Benefit-Cost Summary

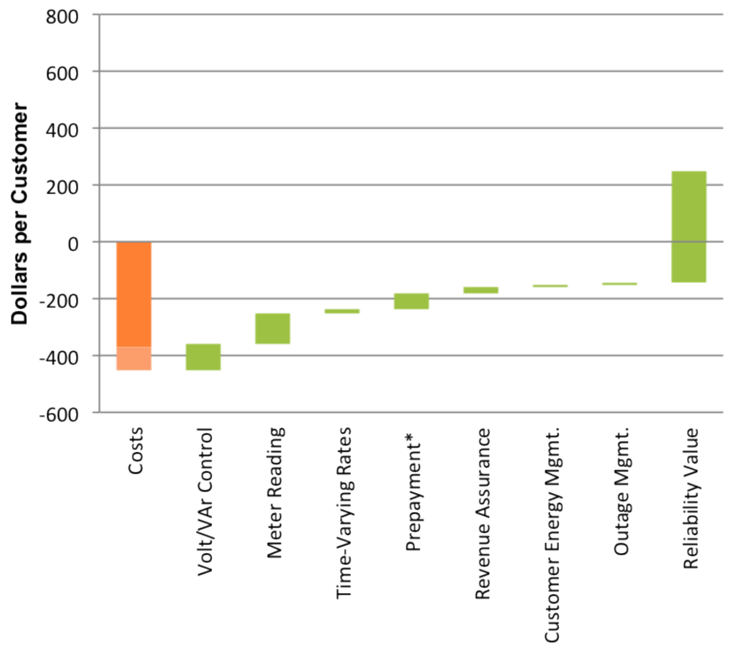
Figure 1 summarizes the Net Present Value (NPV)[6] of benefits and costs for the Reference Case, while Figure 2 does so for the Ideal Case. We assumed a 13-year project life, incorporating 3 years of implementation and 10 years of operation. Based on available research and incorporating the Reference Case and Ideal Case assumptions detailed in this report, we find the ratio of benefits to costs range from 1.5–2.6 to 1 in the Reference Case and Ideal Case, respectively.[7] Subtracting the NPV of total costs from total benefits (direct and indirect) yields net benefits of approximately $247 per customer in the Reference Case and $713 per customer in the Ideal Case.

5 Harvey Kaiser, "Capital Renewal and Deferred Maintenance Programs," APPA Body of Knowledge, 2009, 9.

6 Net Present Value (NPV) is an analytical technique for converting future benefits and costs into present-day dollars for comparative purposes. Please see Section 5, "Costs of the Smart Grid," for more information.

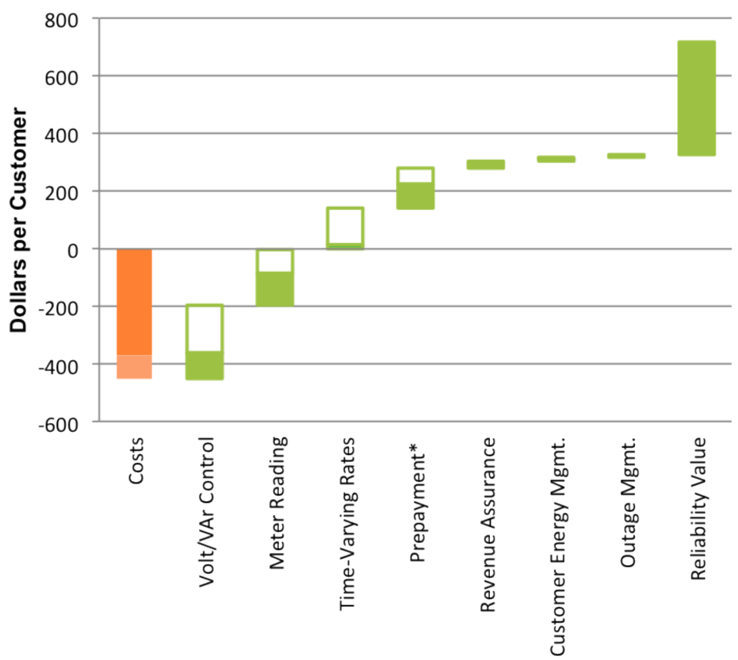
7 Reference Case benefit to cost ratio = ($306.95 + $390.27)/$449.82 = 1.5 (to 1); Ideal Case benefit to cost ratio = ($772.75 + $390.27)/$449.82 = 2.6 (to 1).

Figure 1. Smart Grid costs and benefits by capability: Reference Case



* Includes remote disconnect and reconnect benefits

Figure 2. Smart Grid costs and benefits by capability: Ideal Case



* Includes remote disconnect and reconnect benefits

Open boxes represent the difference in benefit between the Reference Case and the Ideal Case.

Conclusions and Recommendations

The research presented in this review indicates that grid modernization creates direct and indirect economic benefits for customers in excess of costs. The research also indicates that the Smart Grid delivers significant environmental benefits through conservation and renewable generation integration. Opportunities to optimize these benefits are available through a holistic approach involving customer engagement, utility operations, and regulatory/governance systems. The SGCC encourages all stakeholders (utilities, regulators, advocates, and customers) to collaborate in pursuit of optimizing these benefits.

Looking forward, candid conversations among stakeholders about the critical role that the electric distribution grid plays in a community and the kind of grid a community wants to have are essential. Grid upgrades require long lead times; flexibility and reliability must be designed and built well in advance of when they will be needed. The grid we use today was not designed for the demands society seems poised to place on it in the future. Communities need to be asking key questions about the kind of grid they want, the costs required to build it, and priorities and trade-offs they can agree upon.

As the role electric distribution plays in communities' economic vitality and sustainability increases, a new dynamic is needed in the nature of relations among distribution utility stakeholders. This review can serve as a reasonable starting point for the evolution of a new dynamic, and the SGCC hopes stakeholders embrace it and its message in the spirit of objectivity and collaboration in which it has been researched and developed.

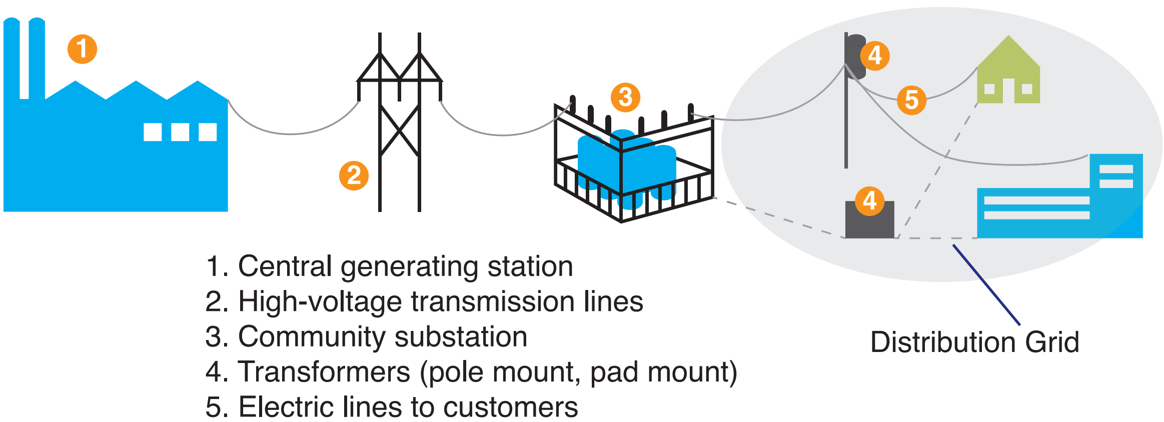
2. INTRODUCTION

What Is a Smart Grid?

The definition of the Smart Grid is presented here only to establish a foundation. What the Smart Grid actually accomplishes – and why stakeholders might want one – is addressed throughout this review.

In recent decades, many industries have grown or perished from the advances made in information and communication technology. However, electric utility systems are still largely operated today in much the same way they were in the early 20th century. Central generating stations produce electric power that is transmitted via high-voltage transmission lines to local community substations. Several primary distribution lines typically extend from each substation, feeding a network of wires and equipment – the distribution grid, or simply "the grid"– that carry electricity to homes and businesses. The distribution grid is the section of the system between the substations and the customers and is the focus of this review.

Figure 3. The distribution grid and its role in the electric utility system



The term "Smart Grid" refers to the computerization of the traditional distribution grid. Until recently, the need to computerize the grid and the communication and information technologies required to do so in a cost-effective manner did not exist. This review will show that the increasing demands society is placing on the grid make computerization more valuable than ever, while advances in technology have made computerization more cost-effective than ever.

How can the traditional grid be computerized? Consider how moving from a traditional grid to a Smart Grid is like moving from a pen and paper to a computer. A computer consists of sensors – such as a keyboard and mouse – that translate and communicate a user's inputs to the computer for information processing and storage. Programs on the computer convert user inputs into spreadsheets or other valuable documents, helping people share information and make decisions. As the inputs change, the shared information and decisions change readily with little or no additional effort. The benefits of using a home computer over pen and paper are fairly clear.

A Smart Grid resembles the computer. Sensors in various locations on the grid collect information on grid operating conditions – including electricity volumes, strengths, and other characteristics – and transmit that information (in some instances continuously and/or instantaneously) to utility computers. These computers can automatically make changes to grid equipment settings without human intervention, continuously and/or instantaneously if needed. In many cases these changes can proactively address issues before they create problems for customers. Information can also be stored for future use, analysis, and decision making by people; for example, in deciding which infrastructure to upgrade based on detailed grid operating data.

In a traditional grid, real-time operating data are not generally available beyond the community substation. To obtain data from the distribution grid, service investigation teams place temporary data-recording devices in select locations, typically only after customer complaints are received. Traditional grid information is limited in timeliness, because it is collected and analyzed long after it has been recorded. Additionally, traditional grid equipment is adjusted only periodically, with many utilities using default "winter" and "summer" settings that suboptimize grid efficiency. Most traditional grid equipment cannot be controlled remotely, so any adjustments generally require the dispatch of service crews.

Why Might Customers Want a Smart Grid?

What does grid computerization offer to utility customers? The computerization of the telephone grid in the late 1980s and early 1990s offers some useful analogies that electric utility customers may be able to appreciate. When the telephone grid was computerized, many new services were suddenly made available to customers, including call forwarding, call waiting, and voice mail. The computerization of the electric grid also offers new capabilities to customers and to utilities, as well. Customers can access electric usage details and money-saving new rate options. Many other new capabilities not immediately apparent to customers are employed by utilities to customers' benefit – reducing operating costs, improving grid efficiency, reducing service outages, and reliably accommodating customer-owned generation such as photovoltaic (PV) solar and demanding new loads such as electric vehicles. In this review we identify and summarize research completed to quantify the benefits of these capabilities and present it in the context of associated costs.

What Are the Components of a Smart Grid?

There are two primary components of a Smart Grid, which can be implemented more or less independently of one another, although there can be advantages to implementing them together. Each component can be implemented in a number of ways, though the details have been intentionally simplified in this review to facilitate presentation and analysis. These two components are Smart Meters (also known as Advanced Metering Infrastructure, or AMI[8]) and Distribution Automation.

Smart Meters

Smart Meters are digital electric meters that take the place of traditional mechanical meters. Traditional mechanical meters use magnets to measure the electric current flowing through the wires leading into a customer's home; the interaction between the magnets causes a metal disk to spin at a rate proportional to the flow of electric current. The disk revolutions are simply counted by the meter, which is read monthly by a utility employee for billing purposes.

Like a traditional meter, a Smart Meter measures electric current. It also stores information and receives and responds to commands and status inquiries from the utility. Smart Meters are much more accurate than mechanical meters, can detect tampering, and can alert the utility when they lose power. Specific Smart Meter capabilities examined in this report include remote meter reading, time-varying rates, prepayment and remote service disconnect and reconnect, revenue assurance, customer energy management, and service outage management.

Distribution Automation

Distribution Automation involves the section of the Smart Grid between the Smart Meter and the local community substation. Although some parts of many utilities' traditional grids have been automated to a limited degree for some time, Distribution Automation is a much more intensive and focused effort to computerize and/or automate grid operations. Distribution Automation capabilities are largely imperceptible by customers, but research indicates their aggregated benefits are potentially significant. These benefits are presented in this review and include improvements in grid efficiency, grid reliability, and the amount of renewable generation (such as PV solar) the grid can reliably accommodate. Specific Distribution Automation capabilities examined in this report include Integrated Volt/VAr Control (IVVC), fault location and isolation, and renewable generation integration.

8 "AMI" generally refers to the Smart Meters as well as associated communications networks, data storage, and data processing systems; we include all of this when use the term "Smart Meter."

Secondary Research Methods Employed in This Review

The SGCC employed a systematic secondary research method to identify and incorporate reference sources included in this review. We considered two types of research for each Smart Grid capability:

- Controlled studies, which we refer to as "studies"
- Surveys and informed analyses, which we refer to as "estimates"

We gave priority to controlled studies wherever available.

Characterization of Benefits in This Review

We have noted a tendency for many researchers, regulators, and utilities to distinguish between "economic benefits to utility operations" and "economic benefits to customers." In cost-based ratemaking, any and all economic benefits to utility operations eventually flow through to customers in future rate cases. Though the timing of these future rate cases is critical if customers are to promptly receive utility operating benefits in the form of lower rates, this distinction is beyond the scope of this review. Accordingly, we simplify all economic benefits found in available research to gross "per customer per year" benefits in this review (unless otherwise noted).[9]

This "per customer per year" metric is different than "per participant per year," in that some Smart Grid benefits accrue disproportionally to customers who participate in certain programs. For example, customers who participate in time-varying rates receive greater benefits than those who do not. Though we note these where appropriate, we average such benefits across all customers (participants and nonparticipants) to facilitate the comparisons to costs.

In order to capture the variation in actual experience with Smart Grid, we present a range of benefits for many capabilities. Where a range is presented, the low end represents what we refer to as the "Reference Case," and the high end represents what we refer to as the "Ideal Case." The Reference Case is based upon conservative assumptions typical of the average capability deployment today. The Ideal Case, on the other hand, represents "the state of the possible" if benefit drivers are thoughtfully optimized.

With this brief introduction to the Smart Grid as it is typically deployed and how it is organized and presented in this review, let's proceed to examine the customer benefits of Smart Meters and Distribution Automation as found in research completed to date.

9 For a more thorough discussion of this topic, see the discussion on traditional ratemaking in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.

3. DIRECT BENEFITS TO CUSTOMERS

In this section, we will review the research findings available to date on the direct benefits that Smart Grid capabilities can deliver to customers. We will examine the Smart Grid capabilities individually, beginning with those which research indicates offer the greatest potential rate relief or conservation benefits realized on customer bills, including:

- Integrated Volt/VAr Control
- Remote meter reading
- Time-varying rates
- Prepayment programs and remote disconnect/reconnect
- Revenue assurance
- Customer energy management
- Service outage management

Integrated Volt/VAr Control

One of the biggest potential Smart Grid benefits is created by a capability called Integrated Volt/VAr Control (IVVC), which helps utilities optimize the power delivered to customers.

	Economic	Reliability	Environmental	Customer Choice
Integrated Volt/ VAr Control Benefits	\$11.24–32.01 per year	Yes but unquantified	Likely – 372 lbs. CO_2e/year	

Description and Value Propositions of Integrated Volt/VAr Control (IVVC)

Integrated Volt/VAr Control helps utilities more effectively manage voltage and power factor[10] on their distribution lines. IVVC can help lower average voltage on a distribution line while ensuring adherence to minimum voltage standards. By lowering the average voltage, utilities can reduce the energy used by customers without any adverse impact on those customers.

For a more detailed understanding of voltage, power factor (or VAr), and how IVVC works to create economic, reliability, and environmental benefits, readers are encouraged to consult the companion report "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.

10 Power factor is a measure of the productive component of energy in a unit of electricity. A distribution grid power factor of 98 percent or 99 percent is considered excellent performance.

Economic Benefits of Integrated Volt/VAr Control

IVVC can help utilities reduce required capacity during peak demand periods and, if used on a continual basis, reduce overall energy use. We find the economic benefits range from $11.24 to $32.01 per customer per year, depending on how a utility uses IVVC.

The typical IVVC implementation is used by utilities during periods of peak demand. An Xcel Energy Smart Grid study found that IVVC helped reduce distribution line voltage from an average of 121 volts to 116 volts, yielding a 3.25 percent reduction in peak demand.[11]

Utilities can also use IVVC on a continuous basis to reduce the energy used by customer loads throughout the year. A study by Ameren Illinois of its continuous voltage reduction test on two distribution lines found reduced energy use in all seasons of the year regardless of distribution line characteristics.[12]

Table 4. Percent reduction in electricity used for each 1 percent reduction in voltage

Distribution Line Type	Summer	Fall
Urban	0.78%	1.24%
Rural/Urban	0.97%	0.44%

Likewise, the aforementioned Xcel Energy Smart Grid study found that IVVC used on a continuous basis helped reduce customer electricity use by 2.7 percent.[13]

Please see the appendices for details on how we calculated the annual economic benefit from the results of these studies. The Ideal Case benefit is reasonably consistent with the Ohio Public Utility Commission's evaluation of Duke Energy Ohio's deployment, which estimated an annual benefit of $35.87 per customer per year with continuous application of IVVC.[14]

11 Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 62.

12 Electric Power Research Institute, *The Smart Grid Demonstration Initiative 5-Year Update,* August 1, 2013, 5.

13 Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 61.

14 $24.6 million in savings divided by 685,859 customers. U.S. Energy Information Administration, *2011 Annual Electric Power Industry Report,* File 2 (retail revenue, sales, and customer counts by state and class of service). Note: includes bundled (electricity and distribution service) and distribution only customers, Duke Energy Ohio.

Reliability Benefits of Integrated Volt/VAr Control

Although less obvious than service outages, power quality events can cause customer disruptions including flickering lights, tripped circuit breakers, and issues with computers and motors.[15] Although we found no specific research quantifying the degree to which IVVC improved power quality, some anecdotal evidence is available. Xcel Energy's study of its Boulder, Colorado Smart Grid deployment (of 46,000 customers) found that customer power quality complaints fell from an average of 30 annually pre-implementation to zero post-implementation.[16]

Environmental Benefits of Integrated Volt/VAr Control

IVVC offers carbon dioxide emissions reduction benefits in direct relation to electricity usage reductions. Applying U.S. Environmental Protection Agency estimates on carbon dioxide equivalent emissions per kilowatt hour,[17] we estimate IVVC can reduce carbon dioxide emissions by 372 pounds per customer per year when used continuously.

There are also likely environmental benefits from peak load reduction, as the use of less efficient peaking plants (generally single-cycle natural gas plants) can be replaced with more efficient plants designed for intermediate use (generally combined-cycle natural gas plants). We found no research to quantify the size of this environmental benefit.

Drivers of Integrated Volt/VAr Control Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Integrated Volt/VAr Control	X			X

Utilities that perform relatively poorly on optimizing power factor and average voltage will likely experience greater improvements by employing IVVC than utilities that perform relatively well on these measures. Additionally, the marginal cost of generation and cost of "peaker" generation plant construction impact the economic benefit available; those areas that have higher costs will experience higher benefits.

As noted above, using IVVC on a continual basis – rather than only during periods of peak demand – can drive substantial economic and environmental benefits.

15 Electric Power Research Institute, *The Cost of Power Disturbances to Industrial and Digital Economy Companies* (study conducted by Primen for the EPRI), June 29, 2001, 4-3.

16 Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 85.

17 1.22 lbs. CO_2e/kWh.

Remote Meter Reading

Among other capabilities, Smart Meters offer utilities the ability to implement remote meter reading. Remote meter reading offers significant reductions in utility operations costs, particularly for those utilities that have not already implemented remote meter reading through other means prior to Smart Meter installation.

	Economic	Reliability	Environmental	Customer Choice
Remote Meter Reading Benefits	$13.68–23.92 per year		Possible	

Remote Meter Reading Description and Value Creation

Remote meter reading enables a utility to obtain electric usage data from meters for billing purposes without sending personnel to read each meter. This avoids the expense, traffic, and potential safety issues (for example, from slips, dog bites, or auto accidents) of sending meter readers to manually read electric meters every month or for "special" meter reads, such as when a customer moves.

In addition to benefits related to labor and vehicle savings, Smart Meter installations can significantly reduce the amount utilities spend on replacing worn traditional meters, at least until those meters begin to age.

Economic Benefits of Remote Meter Reading

We find the economic benefits of remote meter reading to vary between $13.68 and $23.92 per customer per year, depending chiefly on utility operating characteristics prior to implementation. For the Reference Case, we assume that a utility has already automated monthly meter reads via a capability called Automated Meter Reading (AMR), and therefore include only reductions in special meter reads and non-labor cost savings. The Ideal Case assumes that all meter reads – including routine monthly reads – were previously completed manually.

A study by the Ohio PUC of the benefits of Duke Energy's Ohio Smart Grid deployment found a savings of $10.18 per customer per year in special meter reads.[18] The same study also found that reductions in non-labor expenses related to reductions in meter testing, repair, and replacement amounted to $3.50 per customer per year,[19] bringing the total Reference Case economic benefits to $13.68 per customer per year.

18 $6.98 million annual savings divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 80.

19 $2.4 million annual savings divided by 685,859 customers. Ibid., 83–84.

The Ohio PUC study indicated savings of $10.24 per customer per year in routine monthly meter reads.[20] Hence, in the Ideal Case – a utility moving from fully manual to fully automated meter reading – customer economic benefits total $23.92 per customer per year.

Drivers of Remote Meter Reading Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Remote Meter Reading	X		X	

In addition to whether a utility has previously implemented AMR, other operating characteristics serve as drivers of potential benefits. For example, a rural utility with low customer density will have higher pre-implementation meter reading costs than an urban utility with a high customer density. Duke Energy Ohio's service territory, which includes Cincinnati, its suburbs, and surrounding rural areas, is fairly typical with respect to customer density.

Additionally, rules surrounding customer move outs and move ins impact the available benefits. When responsibility for a particular premises' electric bill passes from one occupant to another, some utilities read the meter on the move-out date, while others simply prorate a month's usage based on the move-out date. Those utilities reading the meter on customers' move-out and move-in dates have much higher meter-reading costs than utilities avoiding such reads through proration, and therefore experience greater savings from remote meter reading.

Finally, rules around how customers who opt out of Smart Meter installation are treated can impact the available benefits. Every customer who opts out of Smart Meter installation increases a utility's meter-reading costs. In some cases, whether by policy or by regulation, utilities do not charge the full incremental costs of manual meter reading to those customers who refuse Smart Meters or associated remote communications capabilities.

When the full incremental cost of manual meter reading is not charged to those customers who opt for it, the remaining customers must pick up the difference. Several issues contribute:

- The fixed costs of operating and maintaining two meter-reading systems is significantly higher than maintaining a single meter-reading system.
- The variable incremental cost of manually reading the meters of a limited number of customers spread out over a wide service territory is likely much higher on a "per manual read customer" basis than the meter-reading costs per customer prior to Smart Meter installation.

20 $7.02 million annual savings divided by 685,859 customers. Ibid., 78.

Those utilities that do charge a fee for manual meter reading generally charge a one-time set-up fee (generally \$20–\$75) and an ongoing monthly charge (generally \$10–\$25).[21] The District of Columbia PSC has ordered an estimate, not yet completed as of this review's publication, of PEPCO's manual meter-reading costs post-AMI deployment (Formal Case 1056).

Time-Varying Rates

By recording both a customer's electric consumption and the day and time when it is consumed, Smart Meters facilitate time-varying rate offerings. However, the drivers of available benefits of time-varying rates are among the most complex of the Smart Grid capabilities discussed in this report, and require strong collaboration between utilities, regulators, and customers to optimize.

	Economic	Reliability	Environmental	Customer Choice
Time-Varying Rates Benefits	\$2.00–19.98 per year		11–110 lbs. CO_2e/year	YES

Time-Varying Rate Description and Value Creation

Because most utility customers have only experienced flat-rate pricing, they do not realize that the cost of electricity varies by the time of day or day of the year. Electricity is, however, subject to the same laws of supply and demand that drive the pricing of other goods and services. Utilities pay more for electricity during periods of peak demand – such as a hot summer afternoon with a high demand for air conditioning – and less during off-peak periods, such as a cool fall night.

The flat-rate pricing for electricity that most consumers are familiar with is a blended average of the actual cost of electricity, and it obscures the variance in electricity costs from consumers. This causes what economists call "inefficiency," because customers have no incentive to shift their usage from peak to non-peak times.

Time-varying rates reduce or eliminate this inefficiency by providing customers with an opportunity to reduce their electric bills by shifting their usage from peak to non-peak times. This usage shifting can even create benefits for customers who do not participate in time-varying rates because utility investments in new generation plants – for which all customers pay – can be delayed or avoided.

21 Will McNamara, *AMI Opt Out: Policies, Programs, and Impact on Business Cases* (white paper), West Monroe Partners, 2012, 11.

Economic Benefits of Time-Varying Rates

The economic benefits of time-varying rates consist of two components. The first is a result of the shift in when customers participating in time-varying rates consume electricity. The second is a result of participating customers reducing their overall electricity use. In total, and depending on the variables described in the next section, these benefits range from $2.00 to $19.98 per customer per year.

There are many types of time-varying rates, each with its own pros, cons, and potential benefits.[22] Controlled studies indicate 10 percent to 30 percent reductions in electricity demand at a given point in time for most types of time-varying rates, with certain types generating point-in-time reductions as high as 40 percent or even more.[23]

Research also indicates that most customers participating in time-varying rates not only shift usage from high-priced to low-priced periods, they also reduce electric use overall. This is due in part to the fact that customers participating in time-varying rates are more aware of their overall energy usage, and in part because reductions in use do not always require a commensurate increase. For example, a customer who turns off lights during a peak period has no need to turn on more lights than they otherwise would during a nonpeak period. A survey of available research on the conservation impact of time-varying rates indicates a 4 percent reduction in overall electric use is likely among customers participating in such rates.[24]

Table 5 summarizes economic benefits from time-varying rates for the Reference Case and Ideal Case. Please see the appendices for more detail on the assumptions and calculations.

Table 5. Summary of economic benefits from time-varying rates

	Reference Case	Ideal Case
Customer Participation	2%	20%
Peak Demand Reduction	$1.38	$13.83
Energy Conservation	$0.62	$6.15
Total	$2.00	$19.98

22 For more information, see the discussion on time-varying rates in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from SGCC.

23 Ahmad Faruqui and Jenny Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity." March 12, 2012.

24 Chris King and Dan Delurey, "Efficiency and Demand Response: Twins, Siblings, or Cousins?" *Public Utilities Fortnightly,* March 2005, 55.

It is important to note these are the total benefits to an entire customer base for a utility offering time-varying rates under these assumptions. Depending on the details of specific time-varying rate designs, these benefits are split in some manner between the customers who participate in the rate (who obtain direct rewards by participating) and those who do not (and simply enjoy the lower costs associated with delayed or avoided investments in the form of lower overall rates). This means customers who participate in these rates and shift their usage are likely to receive much more than $2.00–$19.98 in benefits annually, and customers who do not will receive much less.

Environmental Benefits of Time-Varying Rates

Time-varying rates offer carbon dioxide emissions reduction benefits in direct relation to the conservation effect. Applying U.S. Environmental Protection Agency estimates on carbon dioxide equivalent emissions per kilowatt hour, we estimate time-varying rates can reduce carbon dioxide emissions by between 11 pounds and 110 pounds per customer per year.[25]

Customer Option Benefits from Time-Varying Rates

As described in this section, time-varying rates certainly offer customers an opportunity to reduce their electric bills. Lower electric bills and/or increased control over them are likely to increase the satisfaction of participating customers.

Drivers of Time-Varying Rate Benefits

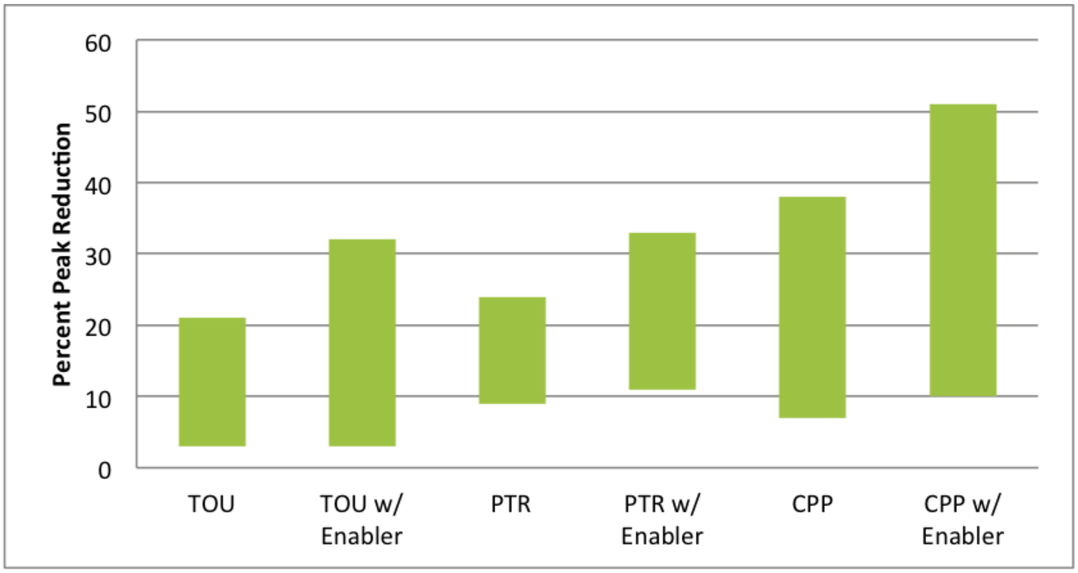
	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Time-Varying Rates		X		X

The single biggest driver of the available benefits of time-varying rates is customer participation rates. There are a number of actions stakeholders can take to increase customer participation rates, though many of them – including changing misperceptions that customers may hold and addressing structural winners and losers – can be challenging. For more detail, please refer to the "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from SGCC.

The second biggest driver is the extent to which customers shift and/or reduce their electric usage. Higher variations between off-peak and on-peak pricing lead to higher shifting behaviors. Enabling technologies such as programmable thermostats can also drive greater shifting. See Figure 4 for a summary of different rate designs and the range of usage shifting for each.

25 See calculations in the appendices.

Figure 4. Summary of time-varying rate impact study results[26]



Notes to Figure 4 (highest and lowest results removed from each study type):
TOU: Standard Time-Of-Use rate design; *n* = 37 studies.
TOU w/Enabler: TOU with enabling technology; *n* = 14 studies
PTR: Peak-Time Rebate rate design; *n* = 12 studies
PTR w/Enabler: PTR with enabling technology; *n* = 17 studies
CPP: Critical Peak Price rate design; *n* = 23 studies
CPP w/Enabler: CPP with enabling technology; *n* = 21 studies

Prepayment Programs and Remote Disconnect/Reconnect

Although a few utilities have offered prepayment programs using traditional meters, Smart Meters make such programs significantly easier to implement. Smart Meters' real-time, two-way communications and remote service disconnect/reconnect capabilities enable more cost-effective administration of such programs by utilities and simplify participation for customers.

	Economic	Reliability	Environmental	Customer Choice
Prepayment Program Benefits	\$7.82–19.56 per year		30–76 lbs. CO_2e/year	YES

26 Ahmad Faruqui and Jenny Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity." March 12, 2012.

Prepayment Program Description and Value Creation

Most customers are billed and pay for electricity after they use it. However, some utility customers appear to prefer to pay as they go. Smart Meters enable utilities to more easily offer such programs, which drive reductions in energy use, increases in customer satisfaction, and decreases in utility operating costs.

Research indicates that customers who participate in prepayment programs use less electricity after signing up for the program than they did before. Almost all prepayment programs involve some sort of display informing participants of their account balance, generally expressed in days of electricity left based on current usage rates. These displays serve as a continuous feedback mechanism, making customers constantly aware of the rate at which they are using electricity. As discussed in the "Customer Energy Management" section, feedback is a critical component of energy conservation.

Electric rates are set at a level sufficient to cover utility operating expenses, including those related to billing and collection. Prepayment programs theoretically should reduce several types of billing and collection expenses, including the cost of printing and mailing bills, bad debt write-offs, service visits, and interest expense. Of these, the reduction in service visit costs is by far the most significant, as Smart Meters' remotely controlled disconnect/reconnect switches alleviate the need for service visits to collect or prompt payment on past-due accounts, post notices, disconnect service, or reconnect service.[27] Utility interest expenses are reduced with prepayment, as utilities need not borrow money to fund the difference between the time traditional billing customers use electricity and the time they pay for it.

Economic Benefits

The economic benefits from prepayment programs stem from the conservation effect of program participants – which accrue directly to participants – and in the reduced billing, collection, and interest expense such programs produce. We find a total benefit of $7.82–19.56 per customer per year from these two factors.

A controlled study conducted upon the introduction of a prepayment program by the Oklahoma Electrical Cooperative finds a weather-adjusted 11 percent reduction in electric usage by prepayment customers after joining the program.[28] Additionally, the utility operating one of the most extensive and longest-running prepayment programs in the U.S., the Salt River Project in Arizona, estimates its prepayment customers reduce electric use by 12 percent after joining.[29]

27 This is a particularly expensive proposition, as two or three truck rolls with a variable cost of $35–$50 each can be required to post notices, disconnect service, and reconnect service to collect a single $100 payment (for example) on a past-due account.

28 Michael Ozog, *The Effect of Prepayment on Energy Use* (Integral Analytics, Inc. research project commissioned by the DEFG Prepay Energy Working Group), March 2013, 2.

29 Institute for Energy and the Environment, Vermont Law School, *Salt River Project: Delivering Leadership on Smarter Technology & Rates,* June 2012, 18.

Long-standing programs, such as those in the United Kingdom and at the Salt River Project in the U.S., indicate participation rates as high as 13 percent[30] and 12.5 percent,[31] respectively. Because it can take decades for a prepayment program to reach these participation levels, we use a 2 percent participation rate to calculate economic benefits in the Reference Case and a more aggressive 5 percent participation rate for the Ideal Case. The conservation effect using these assumptions ranges from $1.69 to $4.23 per customer per year. Recall that these are benefits spread across the entire customer base for the purposes of comparison to costs. In reality, only participating customers receive the conservation benefit, and it can be significant. Given these assumptions, the average benefit per participant indicated is $84.62 annually. Please see the calculations in the appendices for more detail.

We find no controlled studies quantifying billing, bad debt, collection, and interest expense reductions from prepayment programs. A leading vendor of prepayment program software estimates reductions of $357 to $377 in bad debt, billing, and collection expenses (particularly service truck rolls) per participant per year,[32] while the Salt River Project estimated these savings at $300 per participant per year in 2006.[33] Using industry averages, we estimate an additional annual benefit of $6.65 per participant in reduced interest expense. These savings equate to $6.13 to $15.33 per customer per year for the Reference Case and Ideal Case, respectively. Please see the appendices for additional detail on these calculations.

Environmental Benefits

The environmental benefits associated with prepay programs are primary due to the conservation effect demonstrated by program participants. We calculate 30 pounds annual carbon dioxide equivalent reduction per customer in the Reference Case and 76 pounds annual carbon dioxide equivalent reduction per customer in the Ideal Case.[34]

We find no research quantifying the environmental impact of reductions in service calls avoided through Smart Meter–enabled remote disconnect and reconnect capabilities. As these service calls are made in vehicles, there are likely reduced emissions associated with mileage reductions. However, these reductions are likely to be small relative to the conservation effect.

30 Department of Energy and Climate Change, *U.K., Smart Metering Implementation Programme: Data Access and Privacy,* April 2012, 25.

31 Chris Villarreal, *A Review of Prepay Programs for Electric Service,* (policy paper of the California Public Utilities Commission, Policy and Planning Division), July 26, 2012, 4.

32 John Howatt and Jillian McLaughlin, *Rethinking Prepaid Utility Service: Customers At Risk* (white paper by the National Consumer Law Center), June 2012, 14.

33 R.W. Beck, *Prepaid Electric Service* (white paper), March 2009, 10.

34 Please see calculations in the appendices.

Customer Choice Benefits

In some cases, consumers may be signing up for prepay due to an inability to qualify for post-pay; however, research indicates that customers who participate in prepayment programs prefer them to post-use billing and payment. Forty-six percent of prepayment program participants give the Salt River Project a 9 or 10 rating on a 10-point "value received considering the amount you pay" score, compared to 37 percent of non-participating customers.[35] A survey of prepayment program participants in Arizona and Texas finds more than half (62 percent) indicate being "very satisfied" with their programs, while an additional 29 percent are "somewhat satisfied" – totaling 91 percent.[36] Asked if they are likely to recommend prepay electric service to family and friends, the same survey finds that 63 percent were "very likely" to recommend doing so, while an additional 25 percent were "somewhat likely."

These results are likely due to the assistance these programs provide in helping customers manage electricity costs. "Control over energy costs and budget" is the reason most respondents in the Arizona/Texas survey cited for participating in prepayment programs.[37]

Drivers of Prepayment Program Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Prepayment Program	X	X		X

The largest drivers of prepayment program benefits are the customer participation rate and the size of a utility's spending on bad debt, billing, collection, and interest expenses.

35 Bernie Neenan, *Paying Upfront: A Review of Salt River Project's M-Power Prepaid Program* (Technical Update 1020260), Electric Power Research Institute, October 2010, 4-3.

36 EcoAlign, *Prepay Energy's Pathway to Customer Satisfaction and Benefits* (results of consumer research), February 2012, 4.

37 Ibid., 3.

Revenue Assurance

Smart Meters help utilities reduce what they call “unaccounted-for losses.” “Lost” electricity is electricity generated and distributed, but not billed, to customers. Traditional cost-based ratemaking includes such losses in customer rates. (To understand the mechanics, interested readers are encouraged to review the discussion on traditional ratemaking in “Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers,” available from the SGCC.)

Lost revenues result from three primary sources: metering errors, theft, and line losses. Here we will address how Smart Meters defend against metering errors and theft.

	Economic	Reliability	Environmental	Customer Choice
Revenue Assurance Benefits (Reference Case and Ideal Case)	$3.00 per year			

Revenue Assurance Description and Value Creation

Smart Meters are both much more accurate than traditional mechanical meters and offer theft detection capabilities unavailable in traditional meters. We will address these capabilities individually.

Meter Accuracy

State regulators generally prescribe the minimum accuracy standards for meters for the investor-owned utilities they regulate, typically within 2 percent (high or low) of actual electric current flow. A study by the Ohio Public Utilities Commission of Duke Energy’s Ohio Smart Meter deployment found that the analog meters being replaced were accurate to within 0.53 percent of actual use.[38] Manufacturers of most Smart Meters warrant accuracy to within 0.5 percent of actual use, a four-fold increase in accuracy over most states’ regulatory rules. The Ohio PUC study found Smart Meters to be accurate to within 0.167 percent,[39] a threefold increase in accuracy over the old analog meters. Additionally, this study found that traditional meters were much more likely to be slow than Smart Meters. A customer with a slow meter is charged for less electricity than he or she is actually using. All other customers make up for these customers’ underpayments in the form of slightly higher rates.

38 “Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 21.

39 Ibid.

Theft Detection

All customers pay the price for electricity theft in the form of higher rates. Smart Meters can help utilities identify electricity theft and catch it earlier, to the benefit of all customers. Each Smart Meter is equipped with sensors alerting the utility to meter removal – even if it is only momentary – or to the presence of magnets, both of which are not detected by traditional meters. However, the sensors do not help in cases in which a meter is completely bypassed. This is where Smart Meters' capability to measure when power is used can help.

Most customers who steal electricity through meter bypass (literally, with wires) do so on a temporary basis. For example, they might only bypass the meter for three weeks out of every four, allowing some usage to register so as not to raise utility suspicion. These customers simply repeat the on-off bypass pattern each month. Traditional meters, which only count the spins of the dial since the last meter read, cannot catch this type of activity. However, utilities with Smart Meters are developing and applying review algorithms to detect such patterns in the detailed usage data Smart Meters offer.

Economic Benefits of Revenue Assurance

The total revenue assurance economic benefit amounts to $3.00 per customer per year, consisting of $1.56 in meter accuracy[40] and $1.44 in theft detection benefits.[41] Of note, the theft detection benefit is net of detection and prosecution costs.

Drivers of Revenue Assurance Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Revenue Assurance	X			X

It is likely that the greater the average age of the traditional meters that are replaced, the greater the improvement in accuracy and the greater the resultant benefit. In addition, electric rates have an impact. The higher the price per unit of use, the greater the resulting underbillings for a given level of meter error will be. Ohio electric rates are about average compared to the rest of the U.S.[42]

We make no distinction between the Reference Case and the Ideal Case for the revenue assurance benefit, as clear drivers such as customer participation rates are not available to use as a basis for distinguishing between them.

40 $1.07 million in annual revenue divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 85.

41 $990,000 annual benefit divided by 685,859 customers. Ibid, 82.

42 Ohio is in the middle quintile, with 40 percent of states reporting higher rates, and 40 percent reporting lower rates. U.S. Energy Information Administration, "Table 5A. Residential Average Monthly Bill by Census Division, and State 2011," Line 66 (U.S. Total), Column D ("Price").

Customer Energy Management

A traditional electric bill indicates how much electricity a customer uses over a month. Smart Meters record how much electricity a customer uses every 10 or 15 minutes, information that many utilities make available to customers so that they can better manage and reduce their electric use.

	Economic	Reliability	Environmental	Customer Choice
Customer Energy Management Benefits	\$0.77–1.92 per year		14–34 lbs. CO_2e/year	YES

Customer Energy Management Description and Value Creation

Many customers have had access to electric bill histories via a secure utility web page for some time. Some utilities even provide comparisons to anonymous neighbors' historical usage data to help customers benchmark their usage. However, the detailed information from Smart Meters takes the concept of energy usage feedback to a whole new level.

Smart Meters enable utilities to provide access to detailed historical usage data (in 10- or 15-minute intervals) and/or real-time usage data. Most utilities installing Smart Meters offer customers access to detailed historical usage data via a secure Internet website or a smartphone application, generally on a one-day lag. Some utilities also offer their customers access to real-time data via an in-home display, web portal, or smartphone app. This latter capability, in particular, has a demonstrated impact on electricity consumption by providing customers with immediate feedback on their usage and the impact of changes they make to their usage.

Economic Benefits of Customer Energy Management

A survey of electric usage display impact research in Canada found an average 7 percent conservation effect.[43] A similar survey covering several decades of research worldwide found a range of 5 percent to 15 percent in conservation effect from direct, real-time usage feedback.[44] Although these are significant decreases in usage, adoption of real-time energy usage displays is likely to be limited for some time.[45] As a result, and using adoption rates of 2 percent to 5 percent for the Reference Case and Ideal Case, respectively, we find the economic benefits from customer energy management to range from $0.77 to $1.92 per customer per year. As with many other participation-dependent Smart Grid capabilities, these economic benefits are typically much higher for customers using real-time data, and minimal or nonexistent for customers not using them.

Environmental Benefits of Customer Energy Management

Environmental benefits accrue directly from the conservation effect of customer energy management. We calculate 14 to 34 pounds per customer per year in carbon dioxide equivalent emissions reduction.[46]

Drivers of Customer Energy Management Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Customer Energy Management		X		X

The number of customers using real-time usage data is a critical driver of energy management benefits. Research indicates that coupling this information with incentives such as those offered in time-varying rate or prepayment programs can drive greater benefits than either incentives or feedback on their own.[47] Figure 4 summarizes the results of multiple studies, which collectively indicate a greater impact when an incentive program is paired with an enabling technology, such as a real-time energy usage display device.

43 Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence" (meta-analysis), *Energy* 35, 2010, 1.

44 Sarah Darby, "The Effectiveness of Feedback on Energy Consumption" (literature review), University of Oxford Environmental Change Institute, April 2006, 3.

45 Janelle LaMarche, et al, "Home Energy Management: Products and Trends" (white paper), Fraunhofer Center for Sustainable Energy Systems, 1.

46 Please see calculations in the appendices.

47 Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence" (meta-analysis), *Energy* 35, 2010, 5.

Service Outage Management

Smart Meters' instantaneous communications capabilities change the way utilities learn of and respond to service outages, reducing service restoration time and cost. Economic benefits are realized when utilities use this capability to avoid unnecessary investigations of outages reported by customers in error.

	Economic	Reliability	Environmental	Customer Choice
Service Outage Management Benefits (Reference Case and Ideal Case)	$1.18 per year	4.5% outage duration reduction		

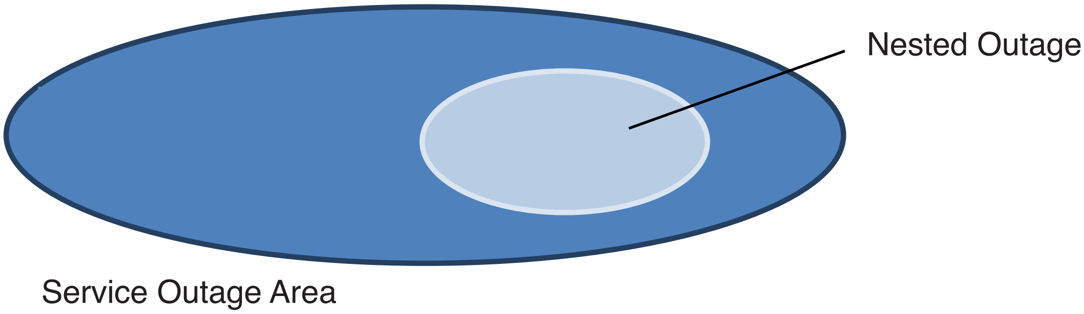
Service Outage Management Description and Value Creation

Utilities have traditionally learned of all but the largest service outages through reports from customers. In fact, an entire software industry segment – outage management systems – has arisen to help utilities log customer outage reports and analyze them in an attempt to determine the extent, nature, and general location of service outages. Unfortunately, customer reports are inherently unreliable; only a small percentage of customers impacted by an outage report it to their utility. Small outages (of one to five homes) can go on for hours before being reported – there is a higher likelihood that no customer is home to detect them – as can outages occurring from midnight to 5 a.m., when most customers are sleeping.

Most Smart Meter models offer a "last gasp" capability, which reports to the utility when the supply of power to the meter is lost. This eliminates or greatly reduces a utility's reliance on customer reports to identify and assess outages. Used in combination with an outage management system, "last gasp" helps utilities learn of outages more quickly and more accurately determine their extent, nature, and general location.

Smart Meters can also respond to utilities' status inquiries. Generally called meter "pinging," a utility can query any Smart Meter to see if it has power. This capability is particularly useful to manage "nested outages" where one outage masks the presence of another, as shown graphically in Figure 5.

Figure 5. Representation of "nested outages"



In a traditional grid, restoration personnel can be unaware of the existence of the nested outage. They repair the larger fault and mistakenly assume that power has been restored to the entire area. Only when customers complain does the utility operating a traditional grid recognize the nested outage. Utilities have traditionally managed this phenomenon by phoning customers to inquire if their power has been restored – a time-consuming, costly, and increasingly ineffective process. With Smart Meter pinging, utilities quickly and accurately verify power restoration and identify nested outages without relying on inbound or outbound telephone calls.

There are concomitant operational benefits that save money. Utilities spend dramatically less manpower (generally overtime and contract labor) understanding the extent and nature of an outage and virtually eliminate the use of resources to verify power restoration.

Additional operational benefits are available from Smart Meter pinging capabilities through reductions in "OK on arrival" service visits. Utilities receive large numbers of outage reports that are not their responsibility to fix, such as when a home's circuit breaker has tripped. With Smart Meter pinging, a utility can instantly and remotely determine if an individual meter has power and help the customer restore power without having to send an employee to investigate.

Service Outage Management Economic Benefits

We find a total expense reduction of $1.18 per customer per year from Smart Meter enhancements to outage restoration and reductions in "OK on arrival" service visits. An evaluation of Duke Energy's Ohio Smart Meter deployment by that state's public utilities commission found that Smart Meters reduce labor costs for power restoration by $1.06 per customer per year.[48] An Xcel Energy study finds the ability to avoid unnecessary "OK on arrival" service visits via meter pinging saves $0.12 per customer per year in operating expenses.[49]

48 $730,000 annual savings divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 87–90.

49 $2,700 annually divided by 23,000 customers with Smart Meters. Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 63.

In addition to these direct cost savings, increased electric service reliability can deliver productivity benefits to local economies. In this review we calculate an indirect economic productivity benefit of $1.80 per customer per minute, and therefore $8.82 in indirect benefits annually from improved service outage management.[50] For more information, see "Estimating the Economic Productivity Impact of Service Outages" in the appendices.

Service Outage Management Reliability Benefits

In a study of the reliability benefits of Smart Meters, Xcel Energy found that outages are reported more quickly, and that the nature and extent of outages – including nested outages – are estimated more accurately. These capabilities produced an average reduction in service outage durations of 4.9 minutes per customer per year,[51] a 4.5 percent decrease in customer minutes per year versus the baseline of 109 minutes per year.[52]

Drivers of Service Outage Management Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Service Outage Management	X			

Not all utilities have designed their Smart Grids to take advantage of Smart Meters' last gasp capabilities. These utilities typically use sensors located throughout the distribution grid in place of Smart Meters to detect outages. These sensors are not as effective as individual Smart Meters at detecting small (one- to five-home) outages, though utilities employing such an approach point out that sensors can be cheaper than Smart Meters to install (due to smaller quantities) and that large outages are a greater priority than small outages.

We make no distinction between the Reference Case and the Ideal Case for the service outage management benefit, as clear drivers such as customer participation rates are not available to use as a basis for distinguishing between the Reference Case and Ideal Case.

50 Indirect benefit per customer/yr = minutes per customer/yr x value/minute = 4.9 x $1.80 = $8.82.

51 224,000 minutes annually divided by 46,000 customers. Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 81–83.

52 "Xcel Energy, *Xcel Energy Quality of Service Monitoring and Reporting Plan* (Boulder region, 2008 CAIDI total, including ordinary distribution interruptions only), April 18, 2013.

4. INDIRECT BENEFITS TO CUSTOMERS AND COMMUNITIES

In Section 3 we examined the direct benefits available from Smart Grid capabilities offering potential rate relief or conservation benefits on customers' bills. In this section we will turn our attention toward Smart Grid capabilities offering indirect benefits to customers and communities, focusing on electric distribution reliability and renewable generation integration.

Fault Location and Isolation

In the section on service outage management we discussed how the Smart Grid, and in particular Smart Meters, help utilities learn of outages faster, estimate the scope of outages more quickly and with less labor, and reduce the cost of false outage reports. Distribution Automation capabilities – specifically, fault location and isolation – help utilities find and fix faults more quickly and isolate fault impacts to fewer customers.

	Economic	Reliability	Environmental	Customer Choice
Fault Location and Isolation Benefits		22.3 minutes/ year		

Description and Value Propositions of Fault Location and Isolation

Fault Location

Whereas Smart Meters can provide general information on the nature and extent of service outages, fault location capabilities provide repair crews with exact fault locations. In a traditional grid situation, distribution control centers will analyze the locations of customers calling about outages to try to narrow down the location of a fault to a particular distribution line for repair crews. Repair crews will then drive along the distribution line until a sign of trouble is encountered (for example, a downed line or power pole, tripped pole-mounted fault indicator, or blown fuse). Underground lines present a particular challenge because no physical damage is apparent, and repairs crews must physically examine multiple equipment vaults or cabinets to identify locations by a process of elimination. All of these efforts take a lot of time.

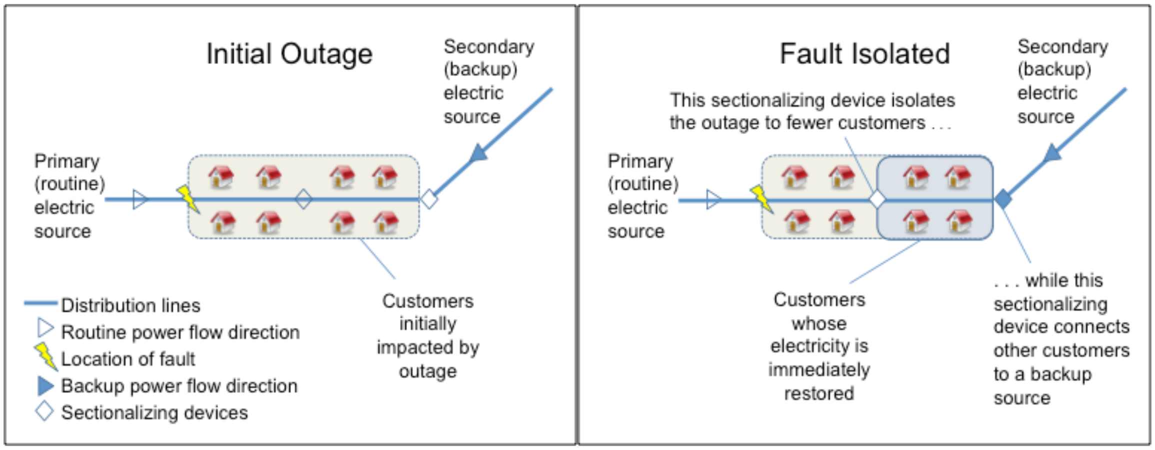
With fault location capabilities, line sensors on either side of the fault measure the time it takes for a pulse sent toward the fault to be reflected back from the fault. Software combines the timing of the reflection with information on other distribution line characteristics to calculate the distance of the fault from each sensor. The distribution control center can then direct a repair crew to within about one hundred feet of a fault.

Fault Isolation

Another type of Distribution Automation capability aimed at improving reliability is called fault isolation. Many people refer to this capability as "self healing," though this is a bit of a misnomer. Faults must still be repaired ("healed"); fault isolation simply reduces the number of customers impacted by any given fault. Although utilities manually execute fault isolation where the hardware is in place today, Distribution Automation significantly increases the geographic extent and level of automation for fault isolation.

In a Smart Grid, several types of devices on a distribution line can serve to isolate a section of distribution line on which a fault has occurred. These devices, generally called sectionalizing devices, operate automatically by sensing a reduction in electric current. Electric service for customers located within the isolated section will not be restored until the fault is repaired. However, once the section is cordoned off, Distribution Automation reroutes power from a nearby distribution line to customers who lie on the other side of isolated section. Figure 6 shows an initial outage, outage isolation, and immediate service restoration to customers beyond the isolated section.

Figure 6. Representation of fault isolation



Reliability Benefits of Fault Location and Isolation

In Xcel Energy's study of its Boulder, Colorado Smart Grid implementation, findings indicate a total reliability improvement of 22.3 minutes per customer per year from fault location and isolation. Xcel Energy found that fault location reduced the duration of outages by 3.5 minutes per customer per year.[53] The same study finds fault isolation to deliver 28,125 customer minutes of outage reductions annually on each of the two distribution lines with the capability. Assuming an average customer count of 1,500 per distribution line, this capability delivers an additional 18.8 minutes of outage reduction per customer per year.[54]

Translating Reliability Improvements into Indirect Economic Benefits

We estimate the economic productivity impact of outages at $1.80 per minute. (See "Estimating the Economic Productivity Impact of Service Outages" in the appendices for more information.) By multiplying the 22.3-minute outage reduction by avoided economic productivity impact of $1.80 per minute, we estimate $40.14 in indirect economic benefits per customer per year.

Drivers of Fault Location and Isolation Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Fault Location and Isolation	X			

The more outages a utility has prior to Smart Grid deployment, the greater the reliability improvement that fault location and isolation capabilities are likely to deliver. Reliability benefits are also likely to increase as the number of sensors and sectionalizing devices placed on a distribution line grows.

53 160,000 customer minutes divided by 46,000 customers. Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 80.

54 Customer counts per distribution line vary widely by utility and within a utility. Anything between 500 and 2,500 customers per distribution line can be considered typical. We chose 1,500 as an estimate. Ibid., 78

Renewable Generation Integration

The degree to which the traditional distribution grid can integrate renewable generation without harm to reliability and efficiency is finite. In this section we will discuss the primary challenges renewable generation presents to grid operators. We will also describe how Smart Meter and Distribution Automation capabilities can help manage the challenges, thereby increasing the amount of renewable generation that can be reliably and efficiently integrated.

	Economic	Reliability	Environmental	Customer Choice
Renewable Generation Integration Benefits	Possible	Likely	Likely	YES

Description and Value Propositions of Renewable Generation Integration

Renewable generation presents two challenges to grid operators. One is the intermittent nature of the most popular types of renewable generation (wind and solar), as they are only productive when the wind is blowing or the sun is shining. Intermittency is an issue with which grid operators must contend regardless of whether renewable generation is centrally located (typically in massive wind farms or solar generating stations that cover thousands or acres) or connected to the distribution grid (for example, PV solar panels mounted on homes). The other challenge relates to the interaction of renewable generation with the distribution grid to which it is attached. The Smart Grid can help address both challenges, with Smart Meters playing a role in intermittency and Distribution Automation helping to reliably and efficiently accommodate customer-sited renewables. We will examine each individually.

Intermittency Challenges

By enabling time-varying rates and customer energy management, Smart Meters allow utilities to engage customers in helping to balance the supply and demand of electricity. When wind and solar generation make up a large portion of a region's generation portfolio, unanticipated changes in wind speed or cloud cover can unexpectedly change electricity supply. Time-varying rates, and particularly dynamic rates that change hourly based on supply and demand, serve to send a price signal to customers about supply and demand.

With dynamic pricing, rates rise in concert with supply reductions or increases in demand and fall in concert with excess supply. Smart Meter–enabled customer energy management systems can work along with dynamic pricing, automatically managing air conditioning and appliance operation within a customer's prespecified instructions as rates rise and fall. This helps provide the flexibility required to reliably accommodate greater levels of renewable generation.

Customer-Sited Generation Technical Challenges

Customer-sited generation, including renewable generation, presents specific technical challenges to distribution grid operators. These issues are readily manageable at low levels relative to a grid's local capacity, but increase in complexity as customer-sited renewable generation levels grow. Customer-sited generation introduces variability that the distribution grid was not designed to handle, reducing grid efficiency and reliability in the process. At higher levels of customer-sited generation saturation, the associated issues include:

- Upstream protective devices (circuit breakers) can trip, causing outages
- Increased variation in voltage and harmonics can degrade power quality
- Increased load and phase variability can make the grid less efficient

Distribution Automation, and a specific set of software and hardware applications generally labeled DERMS (Distributed Energy Resource Management Systems), can help manage the challenges introduced by customer-sited generation. Distribution Automation and DERMS are essential grid investments if high levels of customer-sited renewables are to be accommodated without reductions in grid reliability and efficiency. For more information on these subjects, readers are encouraged to review the section on the challenges of customer-sited generation (renewable and other) in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.

Economic Benefits of Renewable Generation Integration

The economic benefit of accommodating increasing levels of renewable generation is unknown. There are increased costs associated with renewable generation in the short term, including the investments required to accommodate it and the higher capital investment required to build it (per kWh of production relative to natural gas–fired generation[55]). On the other hand, there are economic advantages to renewable generation over the long term, including the avoidance of fuel costs and the potential economic consequences associated with rapid climate disruption.[56] Many researchers have tackled this complex issue and have reached a wide variety of conclusions. As a result, we elect not to quantify the economic benefits of the Smart Grid's capability to integrate greater amounts of renewable generation, but qualify such benefits as "possible."

55 U.S. Energy Information Administration, *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013,* January, 28, 2013, 4.

56 Electric generation accounts for 33 percent of the carbon dioxide equivalent emissions annually produced in the U.S. U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990–2011,* Table 2-12, April 12, 2013, 2–21.

Reliability Benefits of Renewable Generation Integration

Smart Grid investments are likely needed if significant levels of renewable generation are to be reliably and efficiently integrated into the distribution grid. However, experience with customer-sited renewables at a level which impacts reliability is limited, and we found no research predicting the levels at which customer-sited generation will cause reliability issues. The answer is "it depends," based on a host of variables:[57]

- The strength (impedance) of the distribution line at the point of generation connection
- The specifics of a particular distribution grid's design, operations, and customer loads
- The characteristics of the renewable generation asset (relative size, harmonic output, generation profile, etc.)
- The density/locations/characteristics of other local renewable generation installations

IEEE Standard 1547.2, which governs the connection of customer-sited generation to the distribution grid, suggests that such generation amount to no more than 15 percent of a distribution line's maximum capacity. Utilities in California and Hawaii, the states where customer-sited photovoltaic solar installations are arguably the most common, have moved to a slightly more aggressive standard, allowing up to 100 percent of the minimum load recorded for customers on a distribution line in aggregate.[58] Smart Grid Distribution Automation and DERMS capabilities are likely to improve the amount of renewable generation that can be reliably accommodated on the distribution grid.

Environmental Benefits of Renewable Generation Integration

The greater the level of renewable generation the Smart Grid can reliably and efficiently accommodate, the larger the environmental benefits will be. However, it is difficult to quantify the size of the environmental benefits from Smart Grid capabilities designed to integrate renewable generation due to a host of factors:

- The limits of renewable generation saturation that can be reliably and efficiently accommodated by Smart Grid capabilities have not yet been reached and are unknown.
- The speed with which renewable generation levels will grow varies widely by geography and cannot be accurately predicted.
- The level of investment utilities (and ultimately customers) wish to make in order to reliably and efficiently integrate renewable generation is unknown.

As a result, we elect not to quantify the environmental benefits of the Smart Grid's capability to integrate greater amounts of renewable generation, but qualify such benefits as "likely."

57 Electric Power Research Institute, *Integrating Distributed Resources into Electric Utility Distribution System* (white paper), December 2001, 1–3.

58 Interstate Renewable Energy Council, *Integrated Distribution Planning* (white paper), May 2013, 1.

Customer Choice Benefits of Renewable Generation Integration

As previously discussed, some utilities limit the amount of customer-sited generation on their distribution lines. For example, a 15 percent limit means that the utility will allow up to 750 kilowatts of customer-sited generation to be connected to a distribution line with a peak capacity of 5,000 kilowatts. In 2009, the average size of a residential photovoltaic system was 4 kilowatts.[59] That works out to a limit of 187 systems on this hypothetical distribution line. However, a single photovoltaic solar installation on a large retail store can be as large as 300 kilowatts, significantly restricting the ability of other customers to install their own generation.

By increasing the amount of customer-sited generation the distribution grid can reliably accommodate, Distribution Automation and DERMS enable customers (collectively and individually) to connect greater quantities of renewable generation to a Smart Grid than to a traditional grid. For these reasons, we conclude that these Smart Grid capabilities increase customer choice. It should also be pointed out that the Distribution Automation capabilities that enable greater customer-owned renewable generation also enable greater integration of other types of customer-sited resources tied to the grid, from batteries and fuel cells to combined heat and power plants and microgrids.

Drivers of Renewable Generation Integration Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Renewable Generation Integration	X	X		X

The largest driver of renewable generation integration benefits is likely to be the willingness of stakeholders to invest today in reliability and efficiency capabilities that, depending on current grid design and customer adoption of renewables, may not be needed until tomorrow. Grid upgrades require long lead times due to size and scale.

Stakeholder conversations on this topic will likely need to address the issue of cost allocation. When Distribution Automation investments are made to accommodate customer-sited renewables, all customers pay for those investments in the form of higher electric rates over time. Similarly, if renewable generation owners avoid paying for their share of the distribution grid, all other customers pay more in the form of higher electric rates over time. These issues are the subject of vigorous debate among distribution utility stakeholders and are outside the scope of this review.

59 Interstate Renewable Energy Council, *2010 Updates and Trends* (annual industry status report), October 11, 2010, 25. (77 percent DC to AC conversion factor applied to 5.2 kW DC figure cited.)

5. COSTS OF THE SMART GRID (AND RELATIONSHIP TO BENEFITS)

Investments must be made to generate the benefits described in this review, and ongoing expenditures must be made to operate and maintain Smart Grid capabilities over time. In this section we describe the likely costs of the Smart Grid.

This section is organized to help readers understand the manner in which we estimated costs as well as the techniques we used to facilitate comparisons of costs to benefits. This section includes:

- Capital investments
- Ongoing expenditures
- Analysis of cost and benefit data

Capital Investments

The U.S. Department of Energy required utilities to submit project budgets for proposed Smart Grid projects to qualify for its Smart Grid Investment Grant (SGIG) matching grant program. These project budgets, including proposed funding from both utilities and SGIG grants, serve as the basis for our Smart Grid cost estimates.[60]

We reviewed summary grant application data to categorize Smart Grid projects as Smart Meter projects or Distribution Automation projects. The total budgeted costs and counts of customers covered by each project were identified and used to calculate a "cost per customer" for each project.[61] We then calculated an average cost per customer for Smart Meter and Distribution Automation projects.

Table 6. Average cost per customer by Smart Grid component

Project Type	Sample Size	Average Cost per Customer
Smart Meter	24 projects	$291.54
Distribution Automation	12 projects	$63.64

There are, of course, some limitations to this analysis. Utilities sometimes exceed their budgets, and changes to project designs and customer counts likely occurred as projects proceeded from planning through design and implementation. However, for the type of secondary research undertaken for this review, this approach is likely the most accurate available to calculate average Smart Grid cost per customer for the most typical Smart Grid deployments.

60 U.S. Department of Energy, "Project Information" and subsequent web pages. Includes summary information on utility projects awarded Smart Grid Investment Grants funded by the American Recovery and Reinvestment Act of 2009. Accessed August 19, 2013.

61 Clear data on customer counts covered by a particular Smart Grid project were not readily available for all projects. Any projects for which customer counts were ambiguous were removed from the analysis. See the appendices for lists of SGIG projects included in the average cost calculations.

Ongoing Expenditures

Ongoing expenditures for asset operation and maintenance are a requirement for large capital investments. After installation, hardware and software must be maintained, repaired, or replaced as needed and operated on a day-to-day basis.

Experience with these sorts of ongoing expenditures in the Smart Grid space is limited as few deployments are fully in place. Once Smart Grid capabilities are fully deployed, no utilities that we know of track associated Smart Grid operations and maintenance expenditures separately; these ongoing costs become part of routine corporate and local operations and maintenance function responsibilities. The U.S. Department of Energy does not track ongoing Smart Grid operations and maintenance expenditures as part of its SGIG program.

To estimate the ongoing expenditures associated with Smart Grid spending, we turn to "rules of thumb" offered by the operations management discipline. Commonly accepted estimates of annual operations and maintenance (O&M) costs range from 2 percent to 4 percent of capital investment.[62] In this review, 4 percent is used as a conservative estimate.

Analysis of Cost and Benefit Data

This review has presented annual economic benefits on a per customer basis. In this section, we present costs for up-front capital investments and ongoing annual operations and maintenance expenditures, again on a per customer basis. Whereas benefits and O&M expenditures are realized over time, capital investments are made up front. To provide an accurate comparison of costs to benefits, we use an analytical framework called "Net Present Value" (NPV).

NPV translates up-front spending, ongoing spending, and ongoing benefits into today's dollars for comparison purposes, adjusting for the time value of money – the idea that a dollar today is worth more than a dollar 10 years from now due to inflation. The time value of money is reflected by the "discount rate," or the rate at which future costs and future benefits are "discounted" to today's dollar values. NPV is an extremely commonplace practice in the business world, and companies – including utilities – regularly use it to help them decide which of many potential investments they are contemplating offers the best economic rewards.

We chose a discount rate reflecting a customer's perspective. In essence, the discount rate represents the interest a customer could earn by purchasing a low-risk investment, such as a government bond, instead of Smart Grid capabilities. Because we are using a 13-year horizon for our cost-benefit analysis, we use the interest rate from a 10-year U.S. government bond (2.74 percent) for the NPV analysis.[63]

62 Harvey Kaiser, *Capital Renewal and Deferred Maintenance Programs,* APPA Body of Knowledge, 2009, 9.

63 U.S. Department of the Treasury Resource Center, "Daily Treasury Yield Curve Rates (Long Term)." Accessed on August 21, 2013.

Tables 7 and 8 indicate how the NPV is calculated for the Reference Case and Ideal Case. Assumptions include:

- Capital costs are evenly split over the first three years of a deployment.
- A three-year ramp-up period is assumed for capabilities requiring customer participation.
- A 10-year post-implementation evaluation period is used to reflect the likely useful life of Smart Grid components.
- Indirect benefits from reliability improvements (service outage management and fault location and isolation) are included, but indirect environmental benefits (that is, the value of carbon emission reductions) are not.

Table 7. Net Present Value calculation for Smart Grid benefits and costs: Reference Case

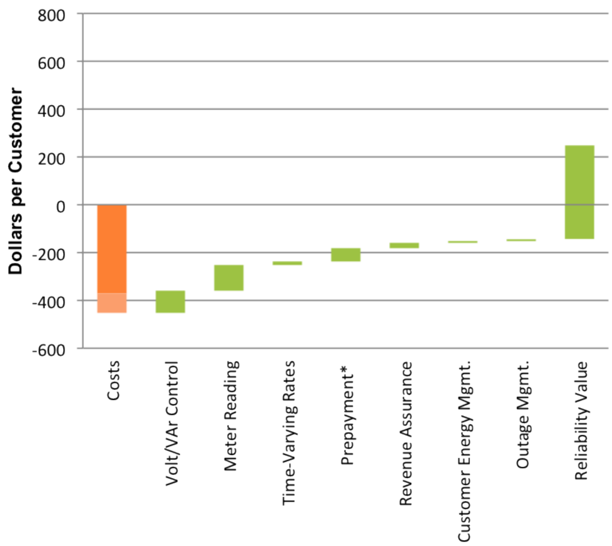
		Deployment Year												
Cost or Benefit Category	**NPV**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
IVVC	89.60				11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24
Meter Reading	109.05				13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68
Time-Varying Rates	14.16				0.66	1.34	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Prepayment	55.38				2.58	5.24	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82
Revenue Assurance	23.91				3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Customer Energy Mgmt.	5.45				0.25	0.52	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Outage Mgmt (direct)	9.41				1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Total Direct Benefits	**306.95**													
Outage Mgmt (indirect)	70.31				8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82
Fault Location & Isolation	319.96				40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14
Total Indirect Benefits	**390.27**													
Smart Meter Costs	-369.22	-97.18	-97.18	-97.18	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66
Distribution Automation Costs	-80.60	-21.21	-21.21	-21.21	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55
Total Costs	**-449.82**													

Table 8. Net Present Value calculation for Smart Grid benefits and costs: Ideal Case

		Deployment Year												
Cost or Benefit Category	**NPV**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
IVVC	255.16				32.01	32.01	32.01	32.01	32.01	32.01	32.01	32.01	32.01	32.01
Meter Reading	190.67				23.92	23.92	23.92	23.92	23.92	23.92	23.92	23.92	23.92	23.92
Time-Varying Rates	141.49				6.59	13.39	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98
Prepayment	138.52				6.45	13.11	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56
Revenue Assurance	23.91				3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Customer Energy Mgmt.	13.60				0.63	1.29	1.92	1.92	1.92	1.92	1.92	1.92	1.92	1.92
Outage Mgmt (direct)	9.41				1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Total Direct Benefits	**772.75**													
Outage Mgmt (indirect)	70.31				8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82
Fault Location & Isolation	319.96				40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14
Total Indirect Benefits	**390.27**													
Smart Meter Costs	-369.22	-97.18	-97.18	-97.18	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66
Distribution Automation Costs	-80.60	-21.21	-21.21	-21.21	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55
Total Costs	**-449.82**													

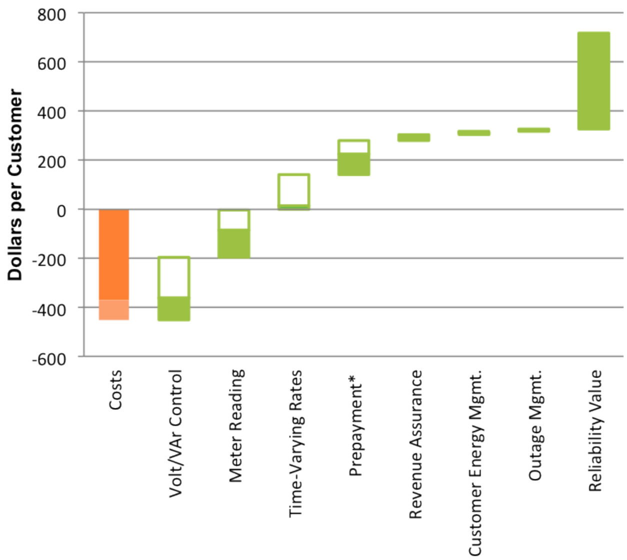
The ratio of benefits (both direct and indirect) to costs is 1.5 to 1 in the Reference Case[64] and 2.6 to 1 in the Ideal Case.[65] These results are depicted graphically by Smart Grid capability in the following figures.

Figure 7. Smart Grid costs and benefits per customer: Reference Case



* Includes remote disconnect and reconnect benefits

Figure 8. Smart Grid costs and benefits per customer: Ideal Case



* Includes remote disconnect and reconnect benefits

Open boxes represent the difference in benefit from the Reference Case to the Ideal Case.

64 Reference Case benefits to cost ratio = ($306.95 + $390.27)/$449.82 = 1.5 (to 1).
65 Ideal Case benefits to cost ratio = ($772.75+$390.27)/$449.82 = 2.6 (to 1).

6. CONCLUSIONS AND RECOMMENDATIONS

In reviewing and synthesizing research on the actual benefits and costs of Smart Grid capabilities and investments, the SGCC intended to provide stakeholders with new insights into the current and potential value of grid modernization and identify associated drivers of that value. While we believe this review has accomplished these objectives, we are struck by the increasingly critical role electric distribution grids will play in the future economic vitality, productivity, and sustainability of the communities they serve. As a result, we have come to see this work as an opportunity to chart a new course in the manner in which stakeholders collaborate to establish and execute a common vision for the distribution grids that serve them. In addition to summarizing our findings, drivers, and opportunities, this section also includes recommendations for researchers and stakeholders.

Findings

We find that the Smart Grid offers a favorable benefit-to-cost ratio when considering both direct and indirect economic benefits. Based on available research and incorporating the conservative Reference Case assumptions detailed in this report, the ratio of direct and indirect benefits to costs is 1.5 to 1.[66] Using the Ideal Case assumptions detailed in this report, the ratio of direct and indirect benefits to costs is 2.6 to 1.[67] In both cases, the indirect benefit from service reliability improvements is significant – and significantly reduces customer inconvenience, as well.

We also find that the Smart Grid offers significant reductions in environmental impact, including both quantifiable and nonquantifiable benefits. Quantified environmental impact reductions of almost 600 pounds of carbon dioxide equivalent emissions per customer per year are available in the Ideal Case from the conservation impact offered by Smart Grid capabilities such as Integrated Volt/VAr Control and time-varying rates. Smart Grid capabilities also appear to enable greater amounts of renewable generation to be integrated by addressing associated intermittency and technical challenges. Although difficult to quantify, the environmental impact reductions from greater amounts of renewable generation are likely many multiples higher than the quantified amounts from Smart Grid capability conservation effects.

Finally, by enabling adoption of new products and services, Smart Grid investments can serve to greatly increase customer choice.

These findings are based on critical assumptions about customer participation levels, utility operating and market characteristics pre- and post-investment, and the speed with which operating cost reductions are effected and recognized.

66 Reference Case benefits to cost ratio = ($306.95 + $390.27)/$449.82 = 1.5 (to 1).
67 Ideal Case benefits to cost ratio = ($772.75+$390.27)/$449.82 = 2.6 (to 1).

Benefit Drivers

Although utilities execute many Smart Grid capabilities "behind the scenes," many other capabilities require extensive and active customer engagement in order to maximize benefits. Customer participation level is the single largest benefit driver for many capabilities that Smart Meters facilitate, including time-varying rates, prepayment programs, and customer energy management. The SGCC encourages utilities to take advantage of the resources and best practices we offer to help engage customers and maximize the benefits from these Smart Grid capabilities.

Another set of drivers involves utility operating characteristics pre- and post-investment, including the variables of electric energy and capacity costs specific to each geography. As examples of the former, utilities with automated meter reading pre-deployment are not likely to secure as much meter-reading cost reduction from the installation of Smart Meters as utilities with manual meter reading. Post-deployment, utilities can choose the extent to which they prioritize and utilize certain Distribution Automation capabilities such as Integrated Volt/VAr Control. As examples of the latter, geographies with higher-than-average electric energy and capacity costs are likely to see greater Smart Grid benefit-to-cost ratios relative to geographies with lower-than-average energy and capacity costs.

Another important variable is the speed with which a utility can begin realizing – and passing on to customers – cost savings from Smart Grid investments. Large Smart Grid deployments are enormous logistical undertakings that can take years to complete. It is not hard to imagine how the first Smart Grid investments a utility makes might require six years to begin paying off for customers – two to three years in field deployment; another year or so in software, process, and customer program development and employee training; and another few years to reach target customer participation levels.

Finally, regulatory rules and norms that can inhibit customer economic benefits exist in many states. For utilities that do business under traditional ratemaking practices, it is important to address the risk that lower sales volumes brought about by Smart Grid–enabled capabilities hinder utilities' ability to recover costs. Several potential solutions to this issue include, but are not limited to, the following:

- Incorporating anticipated sales volume reductions from Smart Grid capabilities into the ratemaking process
- Allowing investor-owned utilities to earn an incentive to maximize Smart Grid–related sales volume reductions in a manner similar to that for demand-side management programs
- Continuing dialog about how to improve traditional ratemaking to better address benefits that require sales volume reductions

Additional regulatory factors, such as those around billing and payment programs, may need to be addressed by stakeholders as various Smart Grid capabilities are deployed. The SGCC hopes this review will help to enable further dialogue and collaboration among stakeholders.

Recommendations for Researchers

This review indicates that the Smart Grid has opened up entire fields of research opportunities. Those that appeared to be priorities to us as we completed this review are summarized below.

Customer Engagement

The SGCC is at the forefront of research related to consumers' perceptions and attitudes toward electricity. This review confirms that our focus on this issue is well placed, and we encourage others to join us as we prioritize new efforts:

- What economic, environmental, and community benefit messages engage customers and raise program participation?
- What role can peer influences play in awareness, participation, and behavior change?
- What new products (such as free weekends) and services (such as outage information messages) made possible by the Smart Grid are of greatest interest to customers?

Identification and Communication of Best Practices

Because distribution utilities do not compete against one another, they have a unique opportunity to widely and openly share best practices. Our research indicates that there are several areas that would benefit from increased best practice dissemination among distribution utilities:

- What new uses are utilities finding for Smart Meter and Distribution Automation data?
- What are the best ways to measure Smart Grid benefits and impacts?
- How are stakeholders working to optimize the value drivers described in this review?

Renewable Generation Integration

There is a dearth of information about the integration of customer-sited and renewable generation. Questions for future research include:

- How much customer-sited generation can a traditional grid reliably and efficiently accommodate?
- How much additional customer-sited generation can Distribution Automation capabilities such as DERMs help accommodate?
- What are the economic, reliability, environmental, and customer choice benefits of this increase relative to costs?
- What are the limits and drivers of customer response to notices or price signals?

Recommendations for Stakeholders

The research presented in this review indicates that grid modernization can create direct economic benefit for customers in excess of costs. This review also indicates that significant indirect benefits – primarily from reliability improvements but also from reduced environmental impact – are available to society at large. This review also makes clear that multiple drivers, including those with significant inherent complexity, can considerably impact the level of benefit customers receive from Smart Grid investments.

The SGCC encourages all stakeholders (utilities, regulators, advocates, customers, and legislators) to prioritize collaboration in pursuit of workable solutions to increase customer participation, speed benefit recognition, and address regulatory opportunities.

7. APPENDICES

Reference Case and Ideal Case Benefit Assumptions

Utilities are not likely to experience the same benefits presented in the Reference Case or Ideal Case, as each utility's operating characteristics and market conditions are likely to differ from the assumptions presented in this report. To help report users adjust for specific situations, the primary benefit drivers are listed below along with the assumptions used to create the Reference Case and Ideal Case. Sources for assumptions are footnoted throughout the review.

Table 9. Reference Case and Ideal Case benefit assumptions

Capability	Primary Benefit Drivers	Reference Case Assumptions	Ideal Case Assumptions
Integrated Volt/VAr Control	• Average reduction in peak demand • Average reduction in energy use	• 3.5% peak reduction • n/a	• 3.5% peak reduction • 2.7% energy reduction
Remote Meter Reading	• Type of meter reading (manual or automated) prior to Smart Meter rollout • Policy regarding move ins/move outs (is prorating allowed between meter reads or must meters be read on customer move dates?)	• Routine monthly meter reads previously automated • Prorating prohibited	• Meter reading previously manual • Prorating prohibited
Time-Varying Rates	• Customer participation rates (opt in) • Customer response level to price differentials • Conservation impact • Average peak demand per residential customer • Value of generation capacity avoided • Average usage per residential customer per year • Value of electricity use avoided	• 2% participation • 20% load shift • 4% usage reduction • 2.575 kW/ customer (1) • $134.28/kW year (1) • 11,280 kWh/ year (1) • $0.0682/kWh (1)	• 20% participation • 20% load shift • 4% usage reduction • 2.575 kW/ customer (1) • $134.28/kW year (1) • 11,280 kWh/ year (1) • $0.0682/kWh (1)

Prepay and remote disconnect/ reconnect	• Customer participation rates • Conservation impact • Existence of remote disconnect prohibitions	• 2.5% participation • 11% usage reduction • No remote disconnect prohibitions	• 5% participation • 11% usage reduction • No remote disconnect prohibitions
Revenue Assurance	• Level of electricity theft prior to Smart Meter deployment • Average age of meters being replaced		
Customer Energy Management	• Customer participation rates • Feedback mechanism type • Conservation impact	• 2% participation • In-home display • 5% usage reduction	• 5% participation • In-home display • 5% usage reduction
Service Outage Management; Fault Location and Isolation	• Value assigned to a minute of reliability improvement	• $1.80/minute (weighted average opportunity cost to residential, commercial, industrial)	• $1.80/minute (weighted average opportunity cost to residential, commercial, industrial)
Renewable Generation Integration	• Difference in cost of relative to central resources • Difference in environmental impact vs. central • Value of environmental impact reductions • Ratio of customer-sited to central resources over time		

(1) These assumptions are used throughout the report as appropriate.

Calculation of Benefits

Table 10. Benefit driver assumptions for calculations

Variable	Assumption	Value
A	Average energy use per U.S. residential electric customer per year[68]	11,280 kWh
B	Average peak demand per U.S. residential electric customer[69]	2.575 kW
C	The variable cost of electricity per kWh[70]	$0.0682
D	The value of generation investments delayed or avoided per unit of demand reduced[71]	$134.28 per kW yr.
E	CO_2 equivalent emissions (lbs.) per kWh[72]	1.22
F	Percentage reduction in peak demand from IVVC	3.25%
G	The amount of electric use reduced per year from IVVC	2.7%
H_r	Assumed participation rate in time-varying rates, Reference Case	2%
H_i	Assumed participation rate in time-varying rates, Ideal Case[73]	20%
I	The amount of demand reduced at a point in time from "shifting" by customers participating in time-varying rates	20%
J	The amount of electric use reduced per year among those participating in time-varying rates[74]	4%
K	The amount of electric use reduced per year among those participating in prepayment programs	11%
L_r	Assumed participation rate in prepayment programs, Reference Case	2%
L_i	Assumed participation rate in prepayment programs, Ideal Case	5%
M	Billing and collection expense reduction per prepayment customer	$300

68 U.S. Energy Information Administration, *2011 Annual Electric Power Industry Report* (File 2, Electric sales, revenue, and average price, Column W, total consumers), April 2012.

69 Calculated based on 11,280 kWh per year for an average U.S. residential electric customer assuming a 50 percent capacity factor. Peak demand = (average demand/8,760 hours annually)/capacity factor.

70 U.S. Energy Information Administration, "Table 5.3. Average Retail Price of Electricity to Ultimate Consumers" (Line 14, 2011, Column D, Industrial), September 20, 2013.

71 Kathleen Spees, *Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM,* The Brattlle Group, August 24, 2011. Page 2, Table 1, final column average (PJM 2014/15 CT CONE).

72 U.S. Environmental Protection Agency, *eGRID 2012 Subregion GHG Output Emission Rates for Year 2009,* April 2012. Summary table 1, column = total output emissions rate (lb/MWh). http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf.

73 Testimony of J. Richard Hornby to the Arkansas PSC in Docket 10-109-U, Exhibit JRH-4, page 2, May 20, 2011. "OG&E assumes 20 percent of residential customers will voluntarily enroll in its VPP rates."

74 Chris King and Dan Delurey, "Efficiency and Demand Response: Twins, Siblings, or Cousins?" *Public Utilities Fortnightly,* March 2005, 55.

N	Average monthly bill per prepayment customer[75]	$110
O	Average days' sales outstanding[76]	53
P	Utility weighted average cost of capital (daily)[77]	0.0095%
Q	Bills per year	12
R	The amount of electric use reduced per year among those utilizing an in-home display (conservative end of the range found in research)	5%
S_r	Assumed participation rate in home energy management, Reference Case	2%
S_i	Assumed participation rate in home energy management, Ideal Case	5%

Table 11. Benefit calculations for Reference Case and Ideal Case

Capability	Calculation	Reference Case Value	Ideal Case Value
Integrated Volt/VAr Control peak demand reduction	B x D x F	$11.24	$11.24
Integrated Volt/VAr Control conservation benefit	A x C x G	N/A	$20.77
Integrated Volt/VAr Control CO_2e reduction	A x E x G	Likely	372 lbs.
Time-varying rate peak demand reduction	B x D x H x I	$1.38	$13.83
Time-varying rate conservation benefit	A x C x H x J	$0.62	$6.15
Time-varying rate CO_2e reduction	A x E x H x J	11 lbs.	110 lbs.
Prepayment program conservation benefit	A x C x K x L	$1.69	$4.23
Prepayment program conservation benefit per participant	A x C x K	$84.62	
Prepayment program billing, collection and interest reduction benefit	[M + (N x O x P x Q)] x L	$6.13	$15.33
Prepayment program CO_2e reduction	A x E x K x L	30 lbs.	76 lbs.
Customer energy management benefit	A x C x R x S	$0.77	$1.92
Customer energy management CO_2e reduction	A x E x R x S	14 lbs.	34 lbs.

75 U.S. Energy Information Administration, "Table 5A. Residential Average Monthly Bill by Census Division, and State 2011." Table 5_a, Line 66 (U.S. total), Column C ("Average Monthly Consumption").

76 Top-quartile (better than 75 percent) utilities. *Cash on the Meter* (white paper), Ernst & Young, May 2009, 6.

77 3.47 percent divided by 365 days. Aswath Damodaran, "Cost of Capital by Sector," January 2013. Analysis of 6,177 firms in the Value Line dataset; "Electric Utility (Central)."

Estimating the Economic Productivity Impact of Service Outages

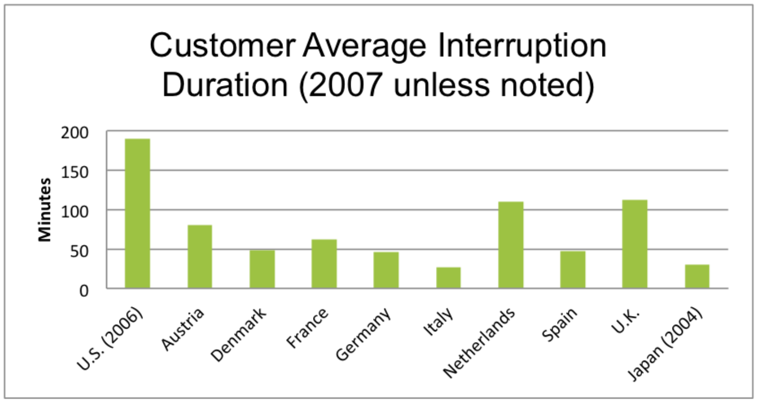
The cost to the U.S. economy of electric service outages is estimated in many studies. All the studies estimate large impacts on productivity – between $30 billion and $400 billion per year.[78] One of the better controlled and more often cited studies (conducted by Primen for EPRI) estimates the cost of power outages in the U.S. at between $104 billion and $164 billion a year.[79] A more relevant and more recent Lawrence Berkeley National Laboratory study estimates the opportunity cost at $80 billion annually.[80]

The high productivity costs of service outages stems from several sources:[81]

- Lost business sales
- Spoiled production runs
- Spoiled experiments
- Spoiled food
- Property damage (from failed protection systems)
- Associated health and medical issues

The U.S. economy competes with those of other nations. Issues inhibiting the productivity of the U.S. economy, including electric reliability, are a source of concern to lawmakers at the state and federal levels. A comparison of U.S. reliability indicating an opportunity for improvement follows. Research indicates the Smart Grid can significantly improve U.S. service outage performance.

Figure 9. Representative customer average interruption duration indices by nation[82]



78 Greg Rouse and John Kelly, *Electric Reliability: Problems, Progress, and Policy Solutions* (white paper), Galvin Electricity Initiative (now the Perfect Power Institute), February 2011, 4.

79 Electric Power Research Institute, *The Cost of Power Disturbances to Industrial and Digital Economy Companies* (study conducted by Primen), June 29, 2001, ES-3.

80 Kristina Hamachi LaCommare and Joseph H. Eto, *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers,* Lawrence Berkeley National Laboratory (for the U.S. Department of Energy), September 2004, 41.

81 Greg Rouse and John Kelly, *Electric Reliability: Problems, Progress, and Policy Solutions* (white paper), Galvin Electricity Initiative (now the Perfect Power Institute), February 2011, 4.

82 U.S. Source: Joseph H. Eto and Kristina Hamachi LaCommare, *Tracking the Reliability of the U.S. Electric Power System,* Lawrence Berkeley National Laboratory (for the U.S. Department of Energy), October 2008, 25. EU source: Council of European Energy Regulators, *4th Benchmarking Report on the Quality of Electric Supply,* 2008. Japan source: Masanori Kondo, "Activities of the Japan Electricity Task Force for the India Market" (presentation), March 9, 2007, 14.

Translating Reliability Improvements into Indirect Economic Benefits

Using the Lawrence Berkeley National Laboratory's estimate of $80 billion annually in service outage costs as a basis, we attempt to estimate the indirect economic benefits available from service outage reductions delivered by the Smart Grid. Dividing the LBNL estimate by the number of U.S. electric customers estimated by the Energy Information Administration (151.7 million),[83] we estimate an economic productivity impact equal to $527.35 per customer per year from service outages. By applying the U.S. System Average Interruption Duration Index of 292 minutes,[84] we arrive at an estimated economic productivity impact per minute of outage per customer of $1.80.

Commercial and Industrial customers who have more at stake are more interested in improving reliability than the average residential customer, who is more likely to be content with the average 99.95 percent uptime the average U.S. customer experiences.[85] The SGCC encourages stakeholders to consider the future – with increased customer reliance on electricity, increased likelihood of extreme weather events, and the increased reliability challenges likely to be imposed on the grid by electric vehicles and customer-owned generation – when assessing the value of investments in reliability-related Smart Grid capabilities.

83 U.S. Energy Information Administration, *2011 Annual Electric Power Industry Report* (File 2, Electric sales, revenue, and average price, Column W, total consumers), April 2012.

84 Joseph H. Eto and Kristina Hamachi LaCommare, *Tracking the Reliability of the U.S. Electric Power System,* Lawrence Berkeley National Laboratory (for the U.S. Department of Energy), October 2008, 25.

85 Greg Rouse and John Kelly, *Electric Reliability: Problems, Progress, and Policy Solutions* (white paper), Galvin Electricity Initiative (now the Perfect Power Institute), February 2011, iii.

SGIG Projects Used to Estimate Costs per Customer

Smart Meter Projects

- Baltimore Gas & Electric (MD)
- Central Maine Power (ME)
- Salt River Project #1 (AZ)
- Salt River Project #2 (AZ)
- Cleco Power (LA)
- South Mississippi Electric Power Association
- Lakeland Electric (FL)
- Denton County Electric Co-op (TX)
- Cobb Electric Co-op (GA)
- South Kentucky Rural Electric Co-op
- Talquin Electric Co-op (FL)
- Black Hills Electric Utility (CO)
- Black Hills Power (SD)
- Cheyenne Light Fuel & Power Company (WY)
- Entergy New Orleans (LA)
- Navajo Tribal Utility Association (AZ)
- Sioux Valley Southwestern Electric Co-op (SD)
- Woodruff Electric (AR)
- Allete Inc. (Minnesota Power)
- City of Fulton (MO)
- Marblehead Municipal Light Dept. (MA)
- Tri State Electric Membership Co-op (GA)
- Wellsboro Electric Co-op (PA)
- Stanton County Public Power District (NE)

Distribution Automation Projects

- Consolidated Edison Company of NY (NY)
- Avista Utilities (ID)
- PPL Electric Utility Corp. (PA)
- Atlantic City Electric Company (NJ)
- Snohomish County Public Utility District (WA)
- NSTAR Electric Co. (MA)
- Hawaiian Electric Company (HI)
- Memphis Light Gas & Water Division (TN)
- Northern Virginia Electric Co-op (VA)
- Wisconsin Power & Light (WI)
- Powder River Energy Corp. (WY)
- El Paso Electric (TX)

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Appendix A-8

Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

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Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

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PRODUCT DESCRIPTION

Revenue security is a major concern for utilities. Theft of electric service in the United States is widespread. In 2006, the revenue estimate for non-technical losses was $6.5 billion. Non-technical losses are associated with unidentified and uncollected revenue from pilferage, tampering with meters, defective meters, and errors in meter reading. In this report, revenue security describes the use of advanced metering infrastructure (AMI) technology to minimize non-technical losses.

Results and Findings

The report defines revenue security as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. The report distinguishes between revenue losses caused by technical and non-technical factors, with a primary focus on the latter. Integrated with meter data management system (MDMS) technology—software that accepts, stores, and forwards AMI-collected data to utility systems such as billing—AMI significantly improves a utility's ability to monitor customers' electric meters and detect both intentional electricity bypasses and unintentional errors (for example, billing and customer service problems encountered by traditional manual meter-reading operations). The report describes AMI technologies in detail, from enabling hardware and software to transitioning from traditional systems to installation and implementation. The transition from meter reader to meter revenue protection agent also is discussed. A case study concludes the report by describing how PPL Electric Utilities of Pennsylvania successfully deployed and implemented AMR/AMI throughout its entire service territory (1,353,024 meters as of 2006).

Challenges and Objective(s)

Revenue security involves securing revenue that is due distribution utilities from delivery of electricity to end-users. It includes both reducing losses and collecting revenue associated with the electricity delivered. Non-technical distribution losses occur at the point of delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is delivered, measured, and billed. This is the challenge to revenue security.

Applications, Values, and Use

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. After AMI installation, utilities may uncover a substantial number of previously unknown sources of diversion. By reading meters frequently, AMI also identifies bad meters more quickly and reduces the need for estimating unmetered energy use. AMI's improved meter-reading accuracy also results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.

EPRI Perspective

AMI systems provide new and innovative tools for revenue assurance. With comprehensive AMI/MDMS and vigorous meter revenue protection programs, AMI will have a positive impact on minimizing non-technical losses due to theft. In areas other than theft, AMI offers additional advantages, such as using MDMS features in customer service to respond more quickly and accurately to high-bill inquiries.

Approach

The project team gathered information for this report from a variety of sources, including government surveys, industry reports, Internet searches, utilities, and vendors. When determining the impact of non-technical losses on revenue, the team examined aggregate measurements of revenue and distribution losses from reliable government statistical sources and applied ratios from various industry surveys and reports.

Keywords

Advanced metering infrastructure
Revenue assurance
Meter data management systems
Non-technical losses
Meter tampering
Electricity theft

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CHAPTER 1

Revenue Security

Revenue security may be viewed as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. It includes both the reduction of losses and the collection of the revenue that are associated with the electricity delivered. The activities related to revenue security are oftentimes called "revenue protection" or, more recently, "revenue assurance."[1]

Utility revenue is a function of electricity delivered to end-users (kWh) and the billing rate ($/kWh).

This is expressed in the following formula:

$$R = E_d * r$$

Where:

R = Revenue ($)
E_d = Energy delivered (kWh)
r = rate ($/kWh)

The electricity delivered to end-users is generation minus losses in generation, transmission, and distribution. Distribution losses are divided into two components, technical and non-technical.

This is expressed in the following formula:

$$G - (L_g + L_t + L_{d+} L_n) = E_d$$

Where:

G = Gross generation
L_g = Generation losses
L_t = Technical losses – transmission
L_d = Technical losses – distribution
L_n = Non-technical losses
E_d = Energy delivered

Transmission losses and technical distribution losses relate to the physical characteristics and functioning of the electrical system itself. Non-technical distribution losses occur at the point of

[1] Revenue assurance includes theft detection and follow-up, metering malfunctions, billing errors and the like, consumption on inactive accounts, and collections. These activities will be discussed at length in Chapter 2.

delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is *delivered, measured, and billed.* This is the challenge to revenue security.

Distribution Losses

Losses in power distribution systems have two components: technical and non-technical.

Technical Losses

Technical loss is the component of distribution system losses that is inherent in the electrical equipment, devices, and conductors used in the physical delivery of electric energy.

Technical loss is intrinsic to electrical systems, as all electrical devices have some resistance and the flow of currents will cause a power loss (I2R loss). Integration of this power loss over time, i.e. _ I2R.dt, is the energy loss. Every element in a power system (a line or a transformer) offers resistance to power flow and, thus, consumes some energy. The cumulative energy consumed by all these elements is classified as "technical loss." Technical losses are due to energy dissipated in the conductors and equipment used for transmission, transformation, sub-transmission, and power distribution. These occur at many places in a distribution system—for example, in lines, mid-span joints and terminations transformers, and service cables and connections.

Technical losses vary greatly in terms of network configuration, generator locations and outputs, and customer locations and demands. In particular, losses during heavy loading periods or on heavily loaded lines are often much higher than those that occur in average or light loading conditions. This is because a quadratic relationship between losses and line flows can be assumed for most devices of power delivery systems. It is not possible to altogether eliminate such losses, which are inherent in a system; they can, however, be reduced to some extent.

Technical losses include the load and no-load (or fixed) losses in the following:

- Sub-transmission lines
- Substation power transformers
- Primary distribution lines
- Voltage regulators
- Capacitors
- Reactors
- Distribution transformers
- Secondary distribution lines
- Service drops
- All other electrical equipment necessary for distribution system operations

Technical losses also include the electric energy dissipated by the electrical burdens of the metering equipment such as potential and current coils and instrument transformers.

Technical losses can be calculated based on the natural properties of components in the power system: resistance, reactance, capacitance, voltage, current, and power.

Non-Technical Losses

Non-technical loss is the component of distribution system losses that is not related to the physical characteristics and functions of the electrical system. Rather, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These are conditions that the technical losses computation fails to take into account. Such losses are caused primarily by human error, whether intentional or not. Non-technical losses are associated with unidentified and uncollected revenue arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of the utilities due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses.

Non-technical losses also can be viewed as undetected load—customers that utilities do not know exist. When an undetected load is attached to the system, the actual losses increase while the losses expected by the utilities will remain the same. The increased losses will show on the utility's accounts, and the costs will be passed along to the customers as transmission and distribution charges.

Reasons for non-technical (or commercial) losses:

- Non-performing and under-performing meters
- Incorrect application of multiplying factors
- Defects in current transformer (CT) and potential transformer (PT) circuitry
- Non-reading of meters
- Pilferage by manipulating or bypassing of meters
- Theft by direct tapping and so on

All these losses are due to non-metering or under-metering of actual consumption. Non-technical losses occur at many places in a distribution system. These are shown in the following insert.[2]

[2] *Best Practices in Distribution Loss Reduction*, DRUM Program, Power Systems Training Institute, Bangalore – 560070. December 2007. The DRUM (Distribution Reform, Upgrades and Management) project is a series of training and capacity building programs in distribution. The broad objective of the training program is to share relevant regional and international experience in the management of distribution business. The program will cover all the important aspects of the distribution business ranging from regulatory matters such as approaches to tariff setting, open access, and reforms to issues of concern to utilities such as quality of service, information management, and energy efficiency. It is supported by USAID and the Ministry of Power, India.

Losses Due to Non-Technical Reasons	
Loss at consumer end meters	Poor accuracy of meters
	Large errors in CTs/PTs
	Voltage drop in PT cables
	Loose connections in PT wire terminations
	Overburdened CT
Tampering/bypass of meters	Where meters without tamper-proof/temper-deterrent/tamper-evident meters are used
	Poor quality sealing of meters
	Lack of seal issue, seal monitoring and management system
	Shabby installation of meters and metering systems
	Exposed CTs/PTs where such devices are not properly securitized
Pilferage of energy	From overhead "bare" conductors
	From open junction boxes (in cabled systems)
	Exposed connections/joints in service cables
	Bypassing the neutral wires in meters
Energy accounting system	Lack of proper instrumentation (metering) in feeders and detector tubes (DTs) for carrying out energy audits
	Not using meters with appropriate data logging features in feeder and DT meters
	Lack of a system for carrying out regular (monthly) energy accounting to monitor losses
	Errors in sending end meters, CTs and PTs
	Loose connections in PT wires (which result in low voltage at feeder meter terminals)
	Energy accounting errors (by not following a scientific method for energy audits)
Errors in meter reading	Avoiding meter reading due to several causes such as house locked and meter not traceable
	Manual (unintentional errors) in meter reading
	Intentional errors in meter reading (collusion by meter readers)
	Coffee shop reading
	Data punching errors (at MRI and by meter readers)
	Data punching errors by data entry operators
	Lack of validation checks
	Lack of management summaries and exception reports on meter reading
Errors in bills	Errors in raising the correct bill
	Manipulation/changes made in meter reading at billing centers—lack of a system to assure integrity in data
	Lack of a system to ensure bills are delivered
Receipt of payment	Lack of a system to trace defaulters, including regular defaulters
	Lack of a system for timely disconnection
	Care to be taken for reliable disconnection of supply (where to disconnect)

Factors Contributing to Non-Technical Losses

Theft and Non-payment

The most prominent forms of non-technical loss are electricity theft and non-payment. Electricity theft is defined as a deliberate attempt by a person to reduce or eliminate the amount of money he or she will owe the utility for electric energy. This could range from creating false consumption information used in billings by tampering with the customer's meter to making unauthorized connections to the power grid.

Power theft by existing customers is the predominant cause of loss of revenue to the electrical utilities. Almost all customer classes are involved in this: residential, commercial, industrial, and public entities. The consequences of power theft are manifest in many areas of an electric distribution company's business, including transformer failures, equipment breakdowns, poor revenue collection, financial losses, lower credit rating for the utility, increased technical losses, and the corroded integrity of employees.

Theft of power is committed by bypassing the meter or meter tampering. Totally bypassing the meter is done by directly tapping into the distribution line; partial or full load is then fed directly.

There are numerous methods of meter tampering. New methods are constantly evolving and detection of tampering is a continuous challenge for distribution utilities.

Theft can be active or passive. A customer may actively engage in illegal tampering to avoid the registration on the meter, or a customer may take possession of a property, find that electricity and gas supplies are on, and therefore not apply for service, thus avoiding payment without tampering.

Direct tapping of power by non-customers is another source of theft that is widely prevalent in developing countries. This is mainly in domestic and agricultural categories. Geographical remoteness, mass basis for theft, poor law enforcement capability, and inaction on the part of utilities are helping this phenomenon.

Unmetered Connections

In some countries, certain customers are not metered and energy usage is estimated, instead of measured, with an energy meter. Usually, the loads involved are small and meter installation is economically impractical. Examples of this are street lights and cable television amplifiers. Unmetered connections pose problems in correctly estimating consumption, resulting in losses.

Defective Metering

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters.

Tampered, slow-running, stalled, or damaged meters cause substantial losses to distribution utilities. Electromechanical meters tend to get sluggish over a period of time, thus under-recording consumption. Stopped or damaged meters can be in place for many years, resulting in on-going losses.

Virtually all energy meters are subject to these kinds of errors and inaccuracies. Standards and protocols for accuracy audits, repairs, and replacement are required to ameliorate this situation.

Meter-Reading Errors

Meter-reading personnel occasionally make errors in recording their readings. For a good number of services the meter reader, at times, reports nil consumption without any comment. Sometimes the meter reader furnishes no readings or in some cases, furnishes table readings. Another error is the adoption of wrong multiplier factors.

Estimated Bills

Sometimes customer bills are prepared using estimates of consumption. The method of estimating customer consumption can distort recorded losses.

Late Billing and Poor Revenue Collection

Consumer complaints in the billing process can result from incorrect billing due to deficiencies in metering and data processing. Prolonged disputes, lack of consumer-friendly policies, connivance, incorrect identification of category, fictitious billing (of non-existent consumers), lack of reconciliation, and continuous provisional billing are causes for poor revenue collections and, thus, contribute to non-technical losses.

AMI WITH METER DATA MANAGEMENT (MDMS) CAN MITIGATE MANY OF THE FACTORS CONTRIBUTING TO NON-TECHNICAL LOSSES. THE ENABLING TECHNOLOGIES ARE DISCUSSED IN CHAPTERS 2 AND 3.

Non-Technical Loss Contribution to Technical Loss

It is often overlooked that non-technical losses can be a contributing factor to technical loss because of improper load management. Improper load management can lead to overloading of conductors and transformers in the system causing higher losses.

It can be argued that the distortion of load quantities caused by non-technical losses distorts computations for technical losses caused by existing loads, thereby rendering results ineffectual.[3] Energy diversion is a major aggravating factor in this situation.

Reducing non-technical losses may positively impact technical losses by mitigating congestion during periods of peak load when technical losses are particularly high.[4]

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[3] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[4] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Measurement

Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.

Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty is obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable. For example, the framework for the business case adopted by the California Public Utilities Commission lists the reduction of non-technical losses as a benefit, but states that they are "not quantifiable, qualitative."[5]

Utilities rely on studies that are designed to calculate the magnitude, composition, and distribution of system losses based on annual aggregate metering information for energy purchases, energy sales, and system modeling methods. These studies are compared to industry and academic studies and models to establish the magnitude, composition, and distribution of losses.

Utilities have developed methods to measure non-technical losses primarily based on detection by manual meter readings and statistical analysis. These are often inaccurate. This is because the data rely heavily on the records of detected cases, rather than by actual measurement of the electrical power system. The reason that measurement or monitoring the power system is not the preferred method of measuring non-technical losses is because the infrastructure of the system, specifically the metering system, makes accurate and detailed loss determination impossible.[6] Measuring distribution line loses directly is not economic.[7]

The metering system is focused on the end-user, not on intermediary stages in the power distribution where technical and non-technical losses could be more accurately measured.

[5] *AMI Potential Benefits Categories Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure* (Draft Report), Moises Chavez, CPUC and Mike Messenger, CEC April 14, 2004. Easier identification of energy theft is categorized as "not quantifiable, qualitative"; meter accuracy, detection of meter failures, reduction in "idle usage," and billing accuracy are categorized as "short term."

[6] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[7] For the accurate measurement of technical losses on transmission and distribution systems, it would be necessary to install metering equipment at each voltage level of transmission and transformation.

The only real solution for identifying the non-technical loss component from transmission and distribution losses is through studies at the distribution utility level. Technical losses can be isolated at substations, and the differences with end-use consumption calculated from that point. Unfortunately, such studies are not conducted on a consistent or industrywide basis.

To get a magnitude measure of the impact of non-technical losses on revenue for purposes of this study, the approach is to examine aggregate measurements of revenue and "distribution" losses from reliable government statistical sources and apply ratios from various industry surveys and reports. The available data sources and their limitations must be taken into close account when considering the accuracy of the results. Economic loss levels tend to be system-specific. In the end, the resulting measure of revenue impact from non-technical losses is an order of magnitude estimation. Nonetheless, this approach is sufficient to demonstrate the value of each distribution utility taking its own measure of non-technical losses.

Data Sources

Data on revenue losses from non-technical losses are extremely difficult to come by. Data on non-technical losses are not collected by the Energy Information Administration (EIA) or industry associations. Data on the revenue attributable to those losses are not collected or estimated on an industrywide basis. Electric utilities consider these data confidential because they have implications for operating and financial performance.

Statistics on net generation and "transmission and distribution losses and unaccounted for," measured in kilowatt hours, are available in the Annual Energy Review.[8] Statistics on revenue from retail sales to ultimate customers and the supply and disposition of electricity are available from the Electric Power Annual.[9]

The most exhaustive study on revenue *metering* losses per se was made by EPRI in 2000.[10] The focus of this study was metering, anomalies, metering integrity, and theft rather than revenue and the full economic impact of non-technical losses.[11] This study was conducted before the benefits of automatic meter reading (AMR)/AMI had become noticeable. The study looks forward to that day though in its conclusion.

> "[Utilities have] a strong interest in quantifying these losses to assess their full effect on utility revenues and to provide a basis for mitigating technologies, such as Automatic

[8] Table 8.1 Electricity Overview, 1949-2006, Report No. DOE/EIA-0384(2006), Annual Energy Review 2006.

[9] Table 7.3 Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1995 through 2006 and Table ES2 Supply and Disposition of Electricity, 1995 through 2006, Electric Power Annual. October 22, 2007.

[10] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

[11] Ibid. For example, the definition of meter/billing errors states, "Included in this class are all scenarios involving personnel actions, where 'people errors' compromise metering integrity because of inexperience, inattention, lack of review, and lack of training. ... Meter mis-installation falls into this category."

Meter Reading (AMR), and the development of other future programs to reduce non-technical losses."[12]

The Office of Gas and Electricity Markets in the United Kingdom has conducted a number of studies evaluating the cost of distribution losses, including non-technical losses and also illegal abstractions (tampering with meters and illegal connections).[13]

Statistics

Aggregate statistics for transmission and distribution losses are presented in Table 1-1, along with revenue for the corresponding year. From this data the relationships and trends can be observed that offer insights into transmission and distribution losses, technical and non-technical, at a global level. As stated previously in the section on data sources, unfortunately these are the only statistical series that are available that offer an objective and consistent measure of the relevant variables at any level, from generation to end-user.

Table 1-1
Statistics

Key Statistics							
Year	**Net Generation + Imports (million kWh)**	**T&D+UFE Losses (million kWh)**	**Ratio**	**Revenue from Retail Sales ($ million)**	**Revenue Loss T&D+UFE**	**Revenue Loss per million kWh**	**Rev Loss 2.0%**
1996	3,487,684	230,617	6.6%	212,609	14,058	0.0610	4252
1997	3,535,204	224,380	6.3%	215,334	13,667	0.0609	4307
1998	3,659,809	221,056	6.0%	219,848	13,279	0.0601	4397
1999	3,738,025	240,086	6.4%	219,896	14,124	0.0588	4398
2000	3,850,697	243,511	6.3%	233,163	14,745	0.0606	4663
2001	3,775,144	201,564	5.3%	247,343	13,206	0.0655	4947
2002	3,895,231	247,785	6.4%	249,411	15,866	0.0640	4988
2003	3,913,575	227,573	5.8%	259,767	15,105	0.0664	5195
2004	4,004,765	265,918	6.6%	270,119	17,936	0.0674	5402
2005	4,099,950	264,479	6.5%	298,003	19,223	0.0727	5960
2006[P]	4,095,321	250,918	6.1%	326,506	20,005	0.0797	6530

[12] Ibid.

[13] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Transmission and Distribution Losses, Unaccounted for Energy

"Transmission and Distribution Losses and Unaccounted for" (T&D+UFE) is calculated as the sum of total net generation and imports minus total end use and exports.[14] Transmission and distribution system losses, including "unaccounted for energy," are generally defined as a percentage of the difference between total energy input to the network and sales to all customers.

These losses, as the global statistical measure of both technical and non-technical losses, are commonly compared to the aggregate of "Net Generation and Imports" to provide an indication of their magnitude and impact. This comparison is shown in Figure 1-1.

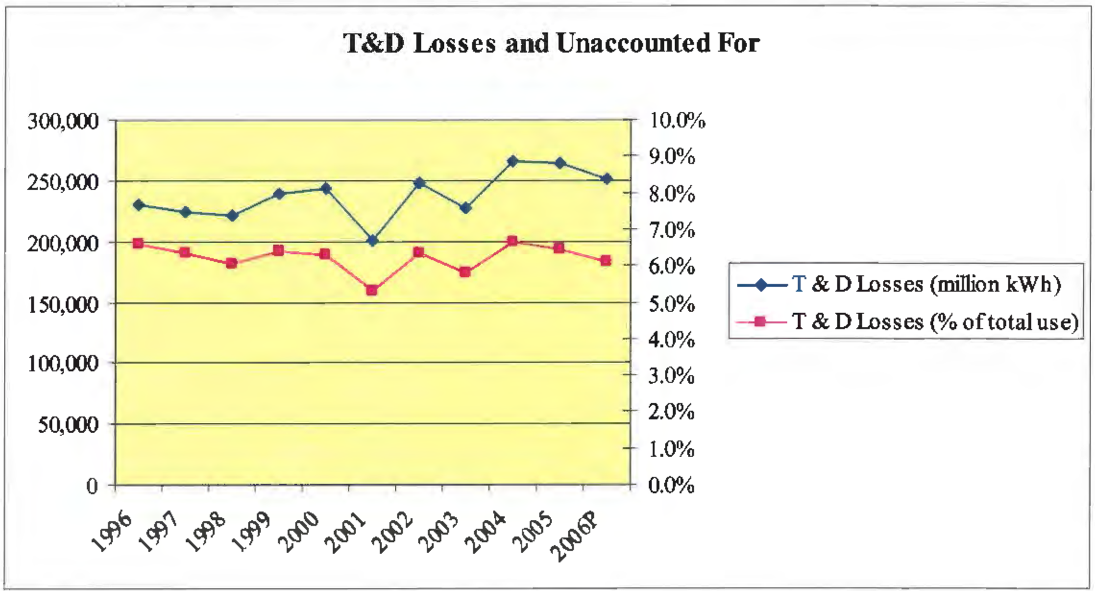

Figure 1-1
T&D Losses

Net Generation and Imports increased from 3.5 quadrillion kWh in 1996 to 4.1 quadrillion kWh in 2006, or 17.4%. Over that same time period, T&D+UFE increased from 230.6 billion kWh to 250.9 kWh, or 8.8%.

The average loss ratio of T&D+UFE to Net Generation and Imports was 6.2% over the eleven years from the beginning of 1996 to the end of 2006.

Revenue and Loss Trends

Revenue increased from $212.6 billion in 1996 to $326.5 billion in 2006, or 53.6%, while T&D+UFE increased only 8.8%. The trend lines for these increases are shown in Figure 1-2. For purposes of this study, it is significant to note that the trend for revenue increases is greater than T&D+UFE. This has a major impact on the importance of revenue loss from non-technical losses.

[14] *Annual Energy Review 2006*, Energy Information Administration, Department of Energy.

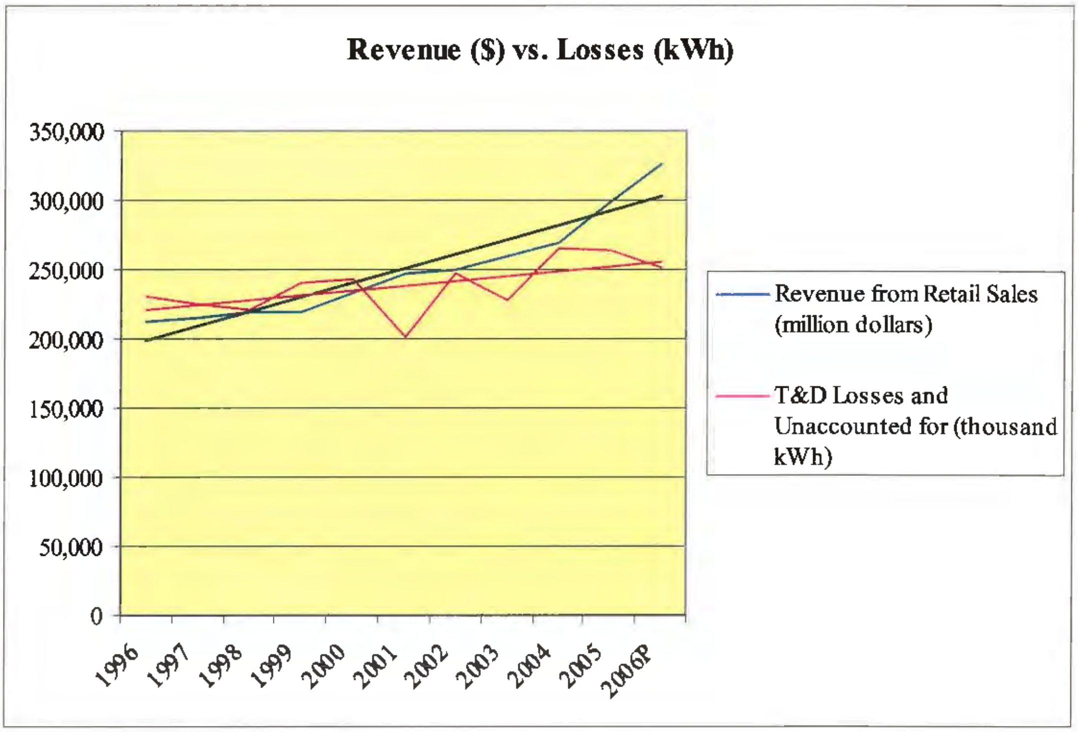

Figure 1-2
Revenue ($) vs. Losses (kWh)

Non-Technical Revenue Loss Estimate

It is difficult to ascertain the extent of technical and non-technical distribution losses separately. The reasons for the difficulty in estimating non-technical losses are discussed in the section on measurement above. For purposes of comparison, and again to get an order of magnitude view of the importance of non-technical revenue losses, a percentage of 2% is most often cited by experts in the industry (Figure 1-3). Applying a constant for the loss ratio, non-technical revenue losses parallel the global.

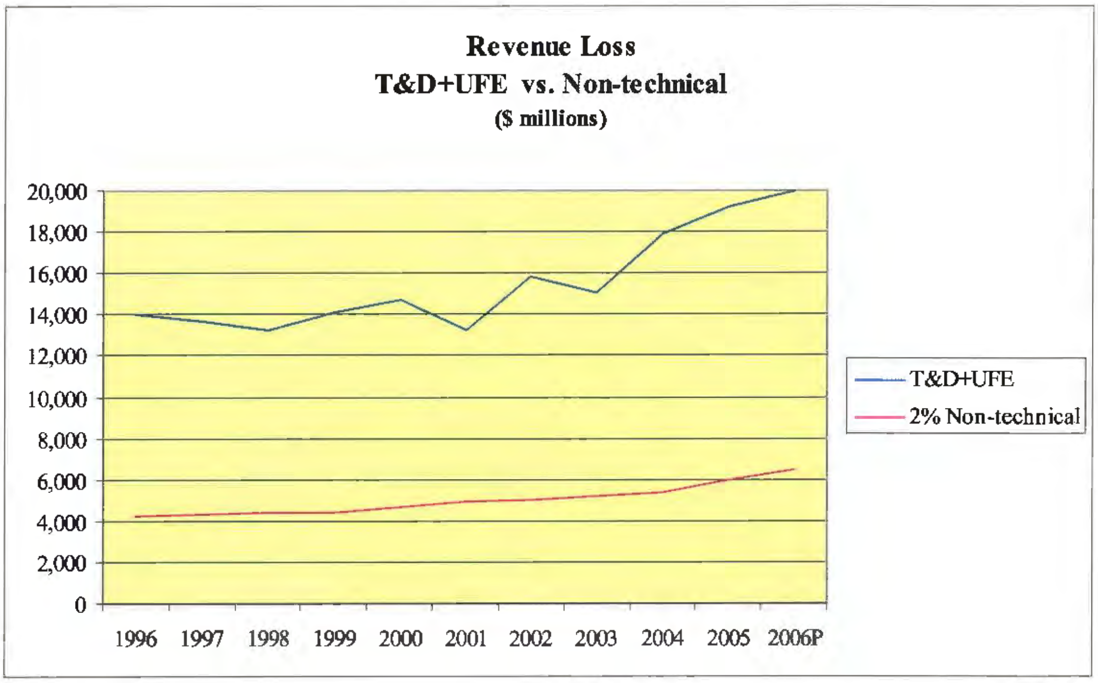

Figure 1-3
T&D+UFE vs. Non-Technical

Revenue Loss per kWh

With revenue rising at substantially higher rates than T&D+UDE losses, revenue loss per kWh is dramatically impacted. Each unit of technical and non-technical losses carries a higher revenue cost, just as each billed kWh carries a higher rate. The upward trend in revenue loss per kWh is shown in Figure 1-4.

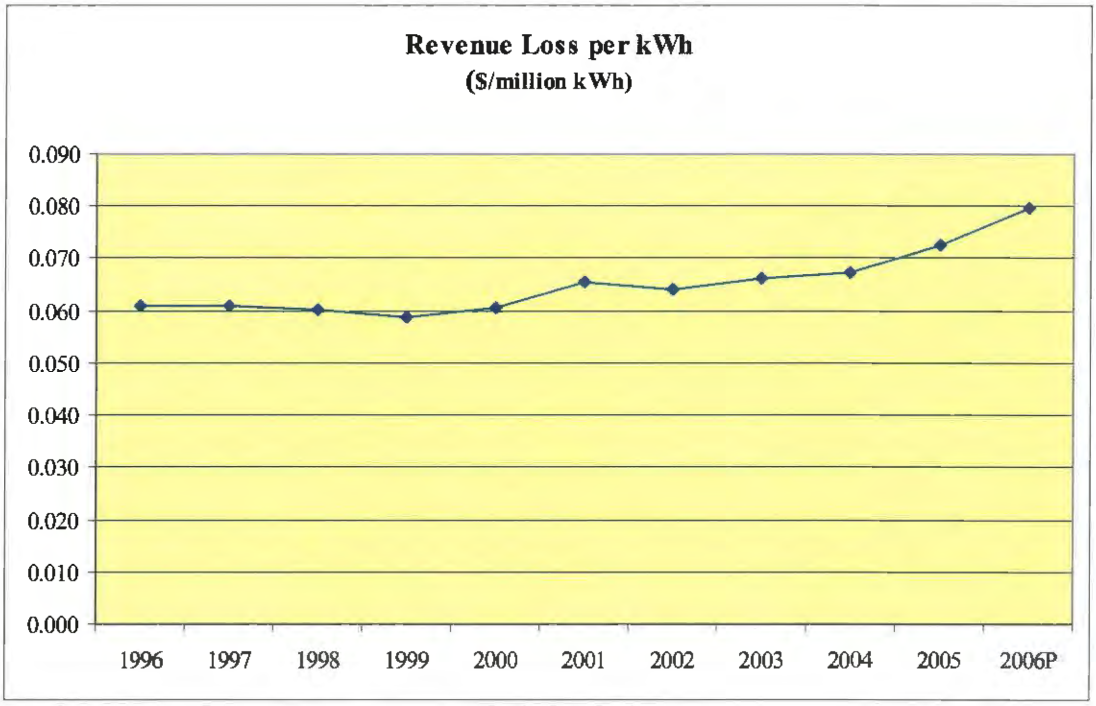

Figure 1-4
Revenue Loss per kWh

Whatever other inferences may be drawn from the data or conclusions reached about technical and non-technical losses, the fact remains that the revenue loss per kWh is increasing. The increases in these losses may be attributable to technical or non-technical components. However, it is most likely that they are more a function of revenue increases themselves. Energy costs have risen over the past decade, and this naturally is reflected in the value of units sold or units lost. Suffice to say, each kWh of reduction in non-technical loss brings the recovery of more revenue today than it did ten years ago.

Assuming that the ratio of non-technical losses to generation remains the same, the value of non-technical losses measured in $/kWh will be higher in terms of revenue. This should be taken into consideration when comparing the revenue losses in earlier studies (prior to 2002) to revenue losses today.

Non-technical revenue loss is greater today than ten years ago, placing greater importance on measures for their reduction.

Studies and Reports

Arizona Public Service Study

After reflecting on several reports and surveys from 1997 to 2000, the Revenue Protection Department at Arizona Public Service (APS) came to the conclusion that "available information regarding energy theft continued to be subjective, at best."[15]

The revenue protection team at Arizona Public Service Company decided to conduct a study of its own.

Two prior studies provided direction and information regarding the amount of various meter problems found in the field and could cite specific percentages. One study by United Energy determined that 2.16% of its meters were faulty. The other study, by the Canadian Electricity Association, found deviations (meter tampering), that would certainly lead to diversion, were definitely occurring across Canada. The average rate for these deviations (tamper rate) was 1.36%.[16]

The goal of the research study at APS was to determine the dollar amount of loss to theft and diversion.

The data in the APS study pointed to a much higher percentage loss among commercial accounts. Of the $7.9 million actual/probable loss, $5.1 million was attributed to commercial accounts. And, similar to the Canadian study, a large number of meter maintenance items were noted. Fully, 6.5% of the meters in the study had some type of maintenance problem.

The APS study concluded that 1.72% of meters were subjected to some form of tampering and that the associated revenue loss was $7.9 million, or 0.518% of revenues.

EPRI Study

The EPRI study on revenue metering loss assessment in 2001[17] concluded that there is "a widespread but unsubstantiated impression in the utility industry that revenue loss from all non-technical sources (excluding bad debt) is between 3% and 4% of utility revenue. Based on this work, we conclude it is far more likely that such losses are between 1% and 2%, and almost certainly are less than 3%. Of course, there will be exceptions in some utility territories. But today's well-managed utility with proactive revenue protection programs should fall below 2%.

[15] *Research Study Quantifies Energy Theft Losses*, John J. Culwell, Supervisor, Revenue Protection Department, Arizona Public Service, Metering International - Issue 1, 2001, January 29, 2001.

[16] Extent of Energy Division on Customer Premises for Canadian Utilities.

[17] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA. Worcester. MA. South Carolina Electric & Gas Co.. Columbia. SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365. This report describes three field studies at three utilities in the United States that inspected meters at over 1000 small- and medium-sized industrial and commercial sites and discusses the available options for utilities seeking to reduce their metering losses.

"Measured in dollars, this gives the following result: A 1.5% average loss corresponds to about $30 million annually for a utility with a million customers and $2 billion of revenue. This equates to about $30 per customer. If the loss is at the upper end of the range, that is 3%, the loss for the same utility corresponds to about $60 million per year, or $60 per customer."

Itron Report to U.S. Department of Energy

In a report submitted to the U.S. Department of Energy in 2005 Itron stated,

"... theft of energy services costs utilities, their shareholders and consumers billions of dollars each year. The consensus estimate among most industry groups and analysts is that energy theft in the U.S. stands between .5 percent and 3.5 percent of annual gross revenues. With U.S. electricity revenues at $280 billion in the late 1990s, theft of electricity alone would equate to between $1 billion and $10 billion annually. A recent article in the Wall Street Journal estimated the nationwide electricity theft figure at $4 billion per year. And with energy prices increasing sharply nationwide, theft of energy services is only likely to increase as consumers struggle to pay energy bills that have doubled or tripled over the past year."[18]

San Diego Gas & Electric

SDG&E demurred from the CPUC Framework for Business Case guidance that benefits from the reduction of theft were non-quantifiable. It proceeded to quantify benefits from AMI in its own business case based on its own estimates of theft. SDG&E claimed $69.4 million in benefits associated with reduced energy theft (both electric and gas), improved meter accuracy, and reduced billing exceptions.[19]

In its opinion approving SDG&E's AMI project, the CPUC stated,

"At the time of the July 2004 Ruling, it was not clear whether energy theft benefits would be quantifiable. That Ruling did not rule out future quantification of benefits. SDG&E has in fact quantified these benefits. We have reviewed SDG&E's calculations of energy theft benefits and find them to be reasonable."[20]

[18] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency,* A Report to the U.S. Department of Energy, Itron. October 2005.

[19] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection,* Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC, March 28, 2006.

[20] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project,* Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

However, there was a procedural qualifier:

"It is unreasonable for SDG&E to include benefits which are not within the scope of benefits envisioned for this proceeding and therefore operational benefits should be reduced by $14.5 million."

Further, SDG&E claimed that no more than 0.65% of electricity revenue is lost due to meter error, energy theft, and unaccounted for energy, including meters that fail and mechanical meters that slow down over time as mechanical parts wear out.

In response to a CPUC data request, SDG&E reiterated that many references provide industry estimates for energy theft and all are consistently in the 1-2% range. The explanation for the basis of this figure was that total losses are not known. Field studies at samples of meter sites uncovered approximately that number of incidences of theft, and five sites published studies that report theft in that range.[21]

Hydro One Estimate

Non-technical losses were estimated by Hydro One by reviewing losses from theft, meter inaccuracies, and unmetered energy in other jurisdictions. Based on an overview of the non-technical losses value from utilities across North America, United Kingdom, and Australia, a value of 1.2% was recommended as a reasonable estimate.

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[22]

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold. The upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors.

"In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold, this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales."[23]

[21] DRA Data Request Number 15, A.05-03-015, SDG&E Response.

[22] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Caryn Hough.1998.

[23] Distribution Line Loss, Exhibit A, Tab 15, Schedule 2, 2006 Distribution Rate Application (EB-2005-0378), Filed August 17, 2005.

Industry Reports

Industry experts estimate that on average, utilities are losing between 2% and 4% in revenues in the meter-to-cash cycle. Studies on electric and gas meter-to-cash cycle losses, also referred to as non-technical revenue losses, indicate that 80% of these losses can be attributed to theft, defective metering, and soft shutoff policies.[24]

Limitation

Some estimates of loss percentages (for example, the 1.5% figure) seem to be predicated mostly on losses from theft. Most of these loss estimates include only the detection of simple energy theft. There may be thefts that are not detected due to sophisticated bypass.[25] Other contributors to non-technical losses, such as defective meters and billing errors, should be given greater weight when deciding on the most likely percentage. Thus, the 1.5% figure is considered as being at the low end of the estimate for non-technical losses.

Revenue Loss

Considering the referenced studies and reports, statistics and analysis, and the opinions of industry experts in revenue protection, a reasonable percentage for non-technical losses is 2.0%. There are indications that the associated revenue loss might be at a lower level, say 1.4%. Some individual company studies suggest that the ratio for revenue losses is lower than the percentage for energy losses. An opposing argument points to the revenue effect due to higher rates reflecting rising energy costs. Nonetheless, for purposes of this study and for comparisons with other estimates in the industry, applying the 2% ratio to revenue seems credible.[26]

The statistical measures for technical and non-technical losses in terms of energy are relatively constant at around 6.1% in the United States. Although there are reasons to argue that technical losses have increased over the past ten years due to congestion, these technical variances are not thought to be greater than the variance in the ratio for losses using aggregate figures. A major study of transmission and distribution losses would be required to conclude otherwise.

Although the statistical measures do not differentiate between transmission and distribution losses, let alone identify non-technical losses (which are, after all, "unaccounted for"), the ratio for non-technical losses measured in terms of energy units cannot reasonably be larger than 4%, given the relative constancy of transmission losses.

[24] Ken Silverstein, Editor-in-Chief, *EnergyBiz Insider*.

[25] There are reasons for bypassing the electric system than avoiding payment. One is the concealment of illegal activity. For example, the main source of electrical theft in Canada derives from indoor marijuana grow operations. The Electricity Distributors Association (Ontario) says statistics show grow operators steal an average of $1500 of electricity per kilowatt-hours per day or 10 times the electricity consumption in an average home. Estimates in Ontario, Canada, alone list over a $500 million power theft loss. Reports of seizures of large indoor grow operations list over a 90% electrical theft/bypass rate.

[26] In the absence of industrywide studies of technical and non-technical losses using a consistent methodology, this is a reasonable and sufficient basis for a discussion of the impact of AMI on non-technical losses.

The findings of numerous studies vary widely with respect to the level of non-technical losses, and even more so when imputing non-technical revenue losses.[27] Estimates of tamper rates range from 1.36% to 1.72%. Metering surveys indicate that defective meters may range from 2.16% to 6.5% of the total installed base. Related revenue losses are imputed anywhere from 0.50% to 3.5%. Many of the differences among these estimates derive from analyzing different customer bases and service territories while other differences relate to measurement difficulties with technical losses.

Estimates of non-technical revenue losses range from 0.5% to 4.0% of annual revenue. The 0.5% estimate is so low as to be almost a margin of error in estimation. Most likely, it relates to simple tampering, excluding by-pass and other sources of non-technical losses. The 4.0% estimate is unrealistically high, most likely based on worst-case scenarios.

Non-technical revenue losses most likely fall within a much narrower range: 1.65% to 2.15%, depending on the utility and service territory. Non-technical revenue losses, within this percentage range, over the past ten years are shown in Figure 1-5.[28] A "mode" of 2% would appear reasonable and reflective of the impact on distribution utilities.

[27] Tamper rates and meter defect information are largely taken from surveys, not a complete census of customer bases. These are subject to wide variances, especially between utilities with different customer mixes. With few surveys at a limited number of utilities, it is difficult to apply them on a global scale.

[28] It should be kept in mind that the growth in non-technical revenue losses over the past ten years is a function of both the level of revenue and the non-technical loss rate. Utility revenues have increased significantly over the past ten years with the rise in energy costs. Thus, even while assuming a constant non-technical loss ratio and undertaking vigorous revenue assurance measures, the impact on revenue is increasing significantly. Further, high costs and rates may lead to increased theft by tampering and diversion by changing the risk/reward ratio. High costs make the "reward" more attractive; AMI/MDMS is a resource for increasing the "risk."

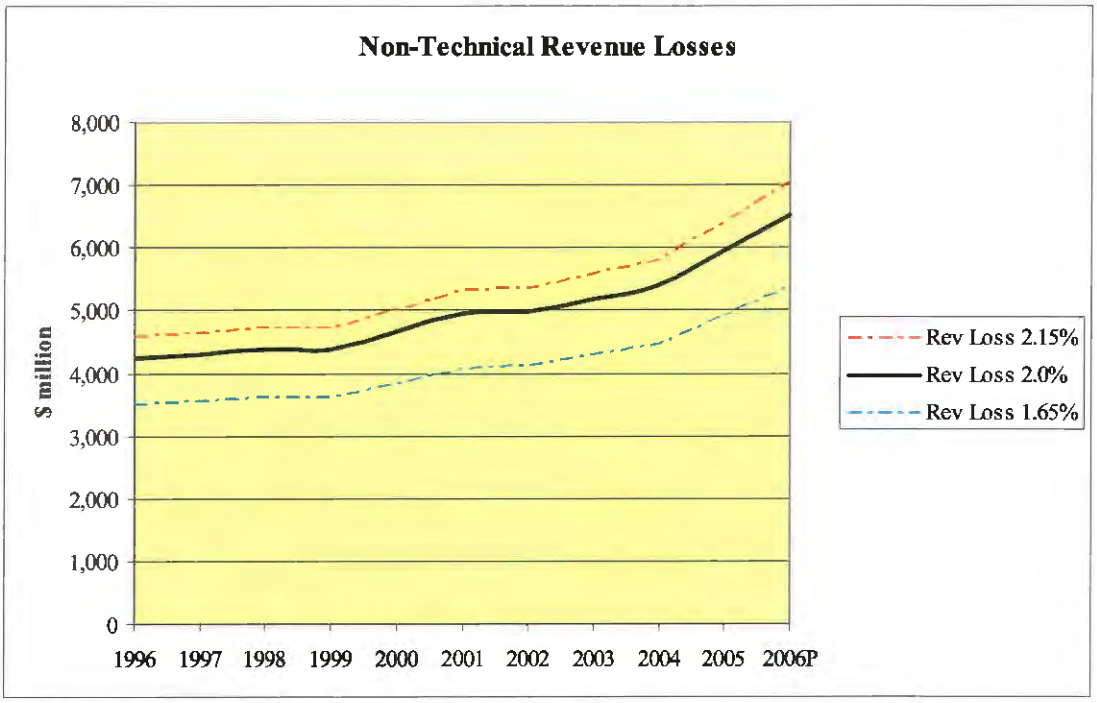

Figure 1-5
Non-Technical Revenue Losses by Year

Based on the 2% rate, non-technical revenue losses are estimated at $6.5 billion for 2006.

International Comparisons

United Kingdom

During the 1980s, some UK electricity companies were losing 2-½% of their total sales because of illegal abstraction (theft) alone. The worst hit areas were London, Merseyside, and Glasgow, with the Northeast having the least amount of theft losses.

Data concerning losses were gained by inter-company comparisons, statistical studies, and engineering studies along with comprehensive studies on street lighting loads to determine distribution system losses and units used in unmetered supplies. This work was underpinned by a number of substation metering exercises whereby meters on particular feeder cables in substations were used to compare the summated meter readings from the properties supplied by those cables.[29]

[29] *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Fellow of the Institution of Electrical Engineers (UK). Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

Overall, Manweb[30] concluded that distribution losses accounted for 5% losses, unmetered supplies (for example, street lights) accounted for 1% losses, and theft accounted for 2-½% losses. This was evidenced by the various studies, metering exercises, signs of serious interference found, and the number of successful prosecutions.

Estimates from four distribution utilities, however, indicate that non-technical losses account for about 3 to 9% of total losses on distribution networks in Great Britain.[31]

Other studies of theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold.[32]

Ontario, Canada

Based on an overview of the non-technical losses from utilities across North America, United Kingdom, and Australia, Hydro One considers a value of 1.2% to be a reasonable estimate for Ontario.[33] This ratio is in line with typical losses incurred by other utilities with a similar mix of rural and urban customers in Ontario. However, it may be low when losses from meter bypass in rural areas are fully discovered and accounted for.[34]

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California, "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[35]

India

The problem of electricity theft is most pronounced in India, where an estimated one-third of all power is "free." Many users there run their own wires from the distribution lines into their homes. This is a tremendous hazard as the cables are strung through populated alley ways and corridors.

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[30] Manweb, a subsidiary of Scottish Power, was among the first electricity companies to gain approval to enter the new market for electricity metering services to domestic and small business customers, which was opened up to competition in June 2004. Under the new arrangements, electricity suppliers have freedom to choose their own agent to collect and process meter readings and to provide and maintain metering equipment. These activities were previously provided on a monopoly basis by the local electricity company.

[31] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[32] *Report on Distribution System Losses*, J.A.K. Douglas, N.J.L. Randles, PB Power report 10025D008, Victoria Australia. February 4, 2000.

[33] *Distribution System Energy Losses at Hydro One*, Kinectrics Inc. Report No.: K-011568-001-RA-0001-R00. July 20, 2005.

[34] Refer to the accounts of theft in Calgary, *Electricity Theft and Marijuana Grow Operations*.

[35] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Carolyn Hough, California Energy Commission. 1998.

Energy theft costs India's utilities close to $5 billion a year and is the major contribution to operating deficits.

These non-technical losses have costs well beyond the impact on revenue. The revenue losses impact the financial strength of the utility to the point that investments in infrastructure are prohibited. When energy is not paid for, the company is not recovering its costs and, thus, is unable to invest in new infrastructure. The result is regular power cuts. Without these investments, service degrades and further losses—technical and non-technical—ensue. For example, in May 2008 the Maharashtra State Electricity Board of India announced that it has been able to reduce non-technical losses by as much as 8% and says that, as a result, it will be able to reduce power cuts in the state.

United States

Losses in the United States in the 3% range seem low in comparison to India. However, when the related revenue losses are calculated, the number captures the attention of regulators and the electric utility industry. There are losers from non-technical losses in the United States as well as less developed countries.

Distribution Loss Ratios

Distribution loss ratios—calculated from generation to end-user—can be compared internationally (Figure 1-6). For developed countries, the ratio is lower than 8%, with non-technical losses in the range of 1.5% to 3.5%. For countries still developing, the loss ratios are more than double, with non-technical losses (mostly from theft) being the major explanation.

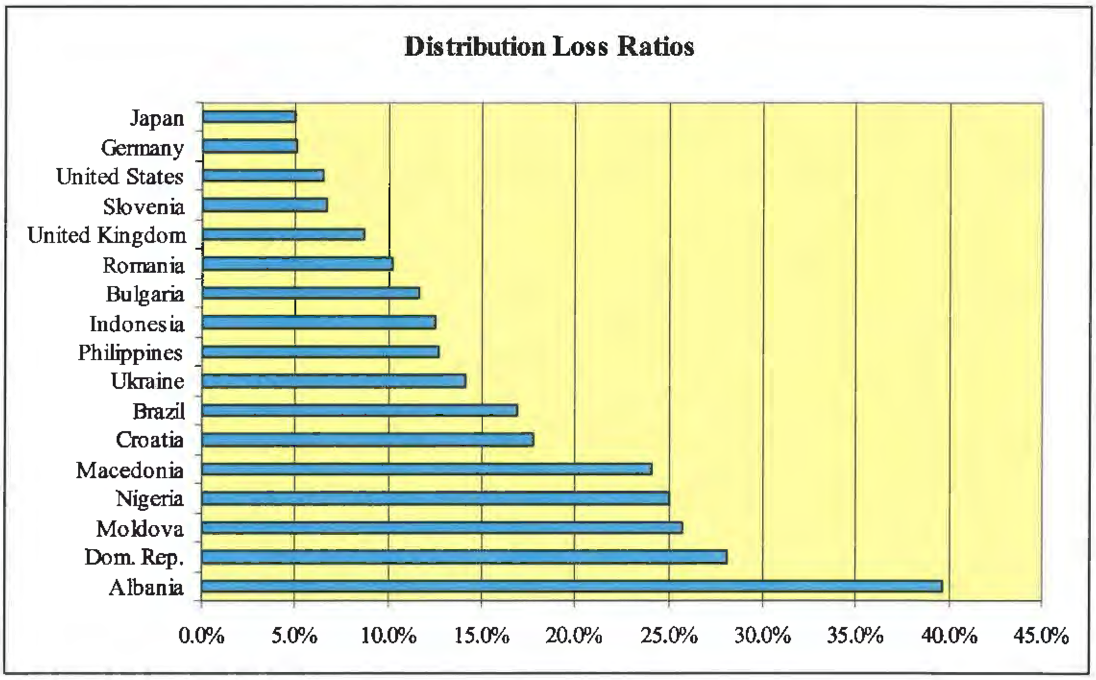

Figure 1-6
Distribution Loss Ratios

Revenue loss resulting from non-technical losses exceeds 40% in many developing countries.[36] Revenue losses of these dimensions have a significant impact on the local economy.[37] It is a problem that governments and utilities must address together. As one observer remarked, "The theft of energy is the largest systematic theft in the world."[38]

Losses Other Than Revenue

Safety

While theft of service is a huge source of revenue loss by any measure, more importantly it poses a serious threat to the safety not only of individuals involved in the theft, but also of utility personnel and the general public.[39] Meter tampering, bypassing, and other means used to steal service place those committing the theft, their families, emergency service personnel, and innocent bystanders in grave danger.

In situations where power must be shut off within a home or business, emergency personnel are at risk of electrocution or burning because meters that have been tampered with may remain "live."

Safety hazards can result in serious injury or death and destruction of public or personal property. These hazards have very real costs associated with them in terms of medical care, loss of productivity, damage to property, and sometimes even services with economic value.

Efficiency

Since losses are factored into the revenue requirement by way of distribution loss factors, and thus included in the rate base, some conclude that there is no real revenue loss to the distribution utility. In this view, reductions in non-technical losses merely shift the source of revenue for the utility among ratepayers. Aside from issues of basic fairness in having some ratepayers bear the burden of non-payment by other users of electricity, the existence of non-technical losses introduces basic inefficiencies into the distribution system.

Non-technical losses have an "efficiency cost." Although a reduction in non-technical losses will represent a reallocation of, rather than a reduction in, electricity consumption, the misallocation of resources introduces inefficiencies. Instead of a direct improvement in social welfare, a redistribution of benefits occurs from those agents whose consumption has been

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[36] *Controlling Electricity Theft and Improving Revenue, Reforming the Power Sector,* Note Number 272, Public Policy for the Private Sector, World Bank. September 2004.

[37] For example, in India electricity theft leads to annual losses estimated at US$4.5 billion, about 1.5% of GDP. The losers are honest consumers, poor people, and those without connections, who bear the burden of high tariffs, system inefficiencies, and inadequate and unreliable power supply.

[38] Kurt W. Roussell, Manager, Revenue Protection, We Energies.

[39] *How Safe is your Utility from Theft of Service?* Revenue Protection Task Force, Energy Association of Pennsylvania. The objective of the Revenue Protection Task Force is to provide education to the public, law enforcement agencies, legislators, and regulators about the facts of energy theft in terms of frequency and quantity of theft.

identified to suppliers and general consumers. However, if consumed units of electricity are correctly allocated, cost signals should encourage a more efficient level of demand for electricity.[40]

The trend toward performance-based rate making highlights the issue of losses where their reduction may change this situation and put in place greater incentives for utilities to reduce non-technical losses.

The reduction of non-technical losses reduces these inefficiencies and rectifies a situation where "lost revenues from energy theft and failure to detect meter errors put upward pressure on rates." Ratepayers benefit when energy theft and meter errors are detected sooner and costs are shifted to the customer who actually used the energy."[41]

Then there is the question of basic fairness. "Although the total revenue requirement does not change through the reduction of energy theft, all law-abiding customers will have lower rates. This is a quantifiable and tangible benefit for our customers."[42]

Technical and commercial losses, however defined, affect allowed tariff levels through a two-step process as shown in Figure 1-7:

Step 1 – Calculation of T&C

$$\text{T\&C} = 1 - \left\{ \frac{\text{Energy Units Billed}}{\text{Energy Units Purchased}} \times \frac{\text{Collection in \$}}{\text{Billing in \$}} \right\}$$

Step 2 – Gross-up Calculation

$$\text{Allowed Units of power purchased} = \frac{1}{1 - \text{T\&C}}$$

Figure 1-7
Calculations

[40] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[41] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

[42] Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 29, Prepared Rebuttal Testimony of James Teeter, SGD&E before the CPUC. September 7, 2006.

The level of losses, therefore, has a direct impact on the price of electricity consumed. The cost of losses is generally spread out over all users.

It must be noted that the full cost of technical losses on a network consists of not only the value of the electricity lost, but also the cost of providing the additional transportation capacity and the cost of the environmental impacts associated with the additional generation that is needed to cover losses.

Unmetered Demand

Loss in revenue results from the uncontrolled increase in demand from unmetered customers. Also, dissatisfied and angry customers can overload the system, which may lead to faults in the distribution network and load shedding with consequent loss of revenue from customers affected.

Energy Theft Impact on Revenue Ratepayer

Energy theft occurs and is a cost of doing business that is borne by all ratepayers. Any reduction in energy theft from the implementation of automated meters will enable SCE to spread its revenue requirement over more energy sales, thus reducing rates.

Edison Smartconnect™ Deployment Funding and Cost Recovery, Errata to Exhibit 3: Financial Assessment And Cost Benefit Analysis, California Public Utilities Commission. December 5, 2007.

Investigation and Prosecution

The adverse financial impacts of energy theft include lost revenues and the costs for investigation and prosecution. Although these costs are not included in non-technical losses, they are borne by ratepayers nonetheless.

Societal Cost and Theft Comparisons

The public is aware of losses from identity theft, stolen credit cards, hold-ups, and personal robberies. In contrast, the theft of electric and natural gas service, despite the magnitude of the problem, has not received much attention from the public or from regulators.

The cost of non-technical losses in electricity distribution to society can be placed in perspective by comparing it to property crimes.

In the Uniform Crime Reporting Program[43] (UCR), property crime includes the offenses of burglary, larceny-theft, motor vehicle theft, and arson. The object of the theft-type offenses is the taking of money or property, but there is no force or threat of force against the victims. The property crime category includes arson because the offense involves the destruction of property. Property crimes accounted for an estimated $17.6 billion dollars in losses.

[43] *Crime in the US, 2006* US Department of Justice, Federal Bureau of Investigation. September 2007.

Larceny-theft is the crime category closest to theft of electrical services. The UCR Program defines larceny-theft as the unlawful taking, carrying, leading, or riding away of property from the possession or constructive possession of another. Examples are thefts of bicycles, motor vehicle parts and accessories, shoplifting, pocket-picking, or the stealing of any property or article that is not taken by force and violence or by fraud. There were an estimated $5.6 billion dollars in lost property in 2006 as a result of larceny-theft offenses.

The revenue estimate for non-technical losses is $6.5 billion. A comparison of non-technical losses to other thefts crimes is shown in Figure 1-8.

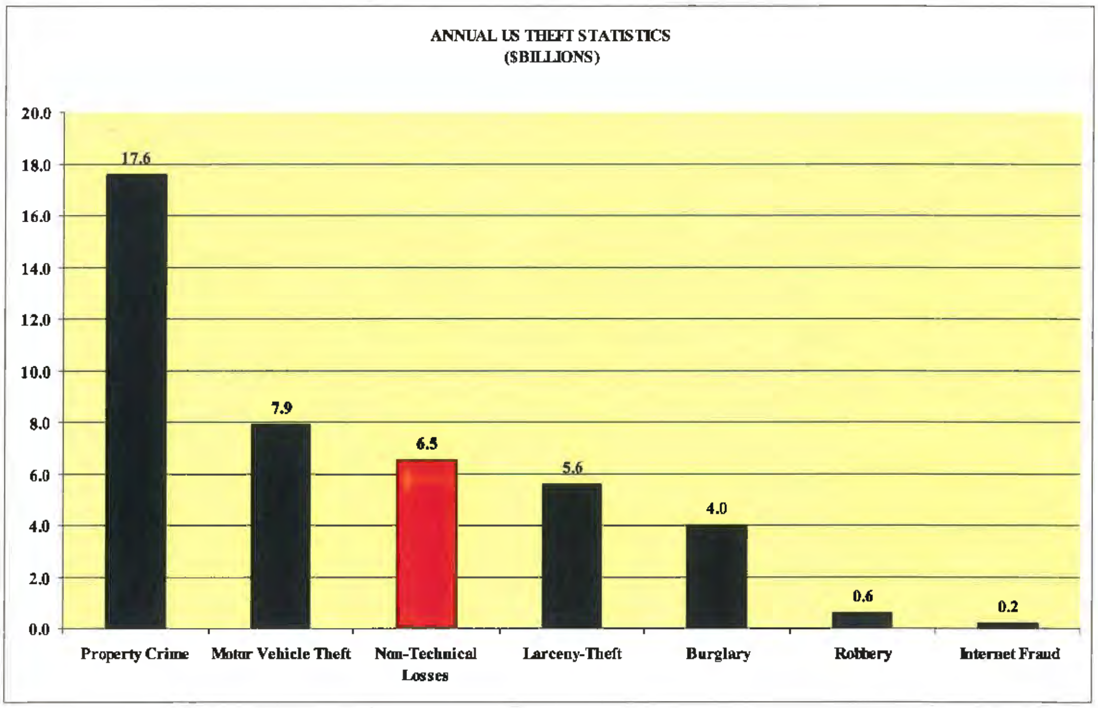

Figure 1-8
Annual U.S. Theft Statistics

2
CHAPTER 2

Revenue Security

"Revenue security" is an apt term to describe the activities intended to protect the distribution system and network resources from external attack or internal subversion, especially theft from diversion by means of "meter bypass." Revenue security ensures that the resources of the electricity industry are available only to those who have the legitimate right to use them. Thus, "revenue security" describes the precautions taken to ensure against non-technical losses.

The activities involved in revenue security are oftentimes called "revenue protection", or more recently, "revenue assurance." Three definitions are presented in the inset below.

Definitions

The term "Revenue Protection" is a colloquialism used by the English-speaking world to refer to the prevention, detection, and recovery of losses caused by interference with electricity and gas supplies.
UK Revenue Protection Association

Revenue Protection is a set of activities to reduce the unauthorized use of energy, ensure metering accuracy and detect meter tampering, and identify customers who fraudulently obtain service.
Kurt W. Roussell, Manager-Revenue Protection, We Energies

Revenue Assurance: A set of activities designed to increase the revenue from providing electric service to ultimate customers, including locating meters without associated customer accounts, relatively high line losses compared with other similar locations, energy theft, and/or improper metering installations.
Federal Energy Regulatory Commission (FERC)

The revenue security function is traditionally performed by utilities' revenue protection departments, using data collected by manual meter reads. The introduction of remote meter-reading technology—beginning with automated meter reading and later including advanced metering systems—changed methods and procedures used for revenue protection, eventually evolving to revenue assurance. These changes in technology and their impact on revenue security are the subject of this chapter.

Meter Readers: The Need for "Eyes in the Field"

The time-honored way of finding electricity theft is through detection by meter-reading personnel. Meter readers are trained and experienced in detecting theft from meter tampering and bypass, and they inspect meters for tampering during regularly scheduled on-site meter reads.

The methods of meter tampering vary from elementary to sophisticated. The ones most commonly detected by meter readers are shown in the insert below.

Common Tampering Techniques

- Stolen meter
- Magnets
- Wire tap on service
- Inverting meter
- Debris, foreign objects inside glass
- Potential link
- Internal—gears, disc, dial hands, adjustment screws
- Load (customer) wires connected to line
- Jumpers—wires connecting line to customer connection

There is some apprehension that AMI, notwithstanding the tamper detection mechanisms in AMI systems, may increase energy theft due to the loss of "eyes in the field" when meter readers no longer visit every meter every month. For example, AMI does not specifically detect and report some kinds of theft, such as taps ahead of the meter.

> "The overall conclusion is that AMR, although it can provide valid and useful assistance in the detection of theft and interference if the system is well thought out and well designed, is not the full answer and that it would be prudent to retain or develop some form of back-up, in terms of conventional revenue protection measures. For instance, one company with an AMR system is considering a new post of Meter Inspector to carry out periodic inspections of customer installations."[44]

There is a concern that AMI—especially after complete meter replacement—will lead to more sophisticated thefts and more bypass, both above and below ground.

Many of these apprehensions and misgivings are founded in experiences with earlier AMR installations. While these are valid concerns, a comparison of AMR and AMI should bring perspective.

[44] OFGEM Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association, Version 3 (final). March 15, 2006.

Comparison of AMR and AMI

Energy theft detection capabilities in AMI systems are far superior to those in simple, first-generation AMR systems. The "infrastructure" in an AMI system includes information systems capable of processing large amounts of interval data for use in discovery of energy theft. This contrasts dramatically with AMR systems, which generally automate only the monthly consumption read.

Prior AMR (not AMI) installations involved tamper alarms so sensitive that false alarms could easily overwhelm the system. Unlike the AMR systems, AMI can intelligently sort and prioritize tamper flags, reducing unnecessary investigations. In addition, AMI, using solid-state meters, is far more tamper-proof than AMR. For example, a solid-state electric meter does not have a spinning disc that can be slowed down. Inverted meters also can be detected quickly through the daily collection of hourly data. Other forms of theft will be discovered through investigation of tamper flags.

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. MDMS applications are essential in the delivery of these solutions. The effectiveness of these solutions is not yet fully documented, as AMI/MDMS have not been deployed on a wide scale over a long period of time. Nevertheless, all indications are that they will be successful when combined with aggressive revenue protection programs with well-trained meter revenue protection agents. With off-cycle reads being supplied through the MDMS, as much as 95% of field service orders for special reads can be eliminated.45

Many on-site inspections by traditional meter readers were focused specifically upon meter tampering and meter anomalies, but did not reach more deeply into supply and service wiring where taps and bypasses are likely to be found. AMI reduces the number of routine site inspections and allows the meter revenue protection agent to concentrate on serious issues of diversion.

AMI Contribution to Theft Reduction

After the installation of AMI, it is expected that utilities may uncover a substantial number of previously unknown sources of diversion. Indeed, some utilities are planning to add staff to handle the increased number of theft cases that will be uncovered.

"During the installation period, SDG&E will need six additional Meter Revenue Protection agents to handle the large number of energy theft cases the company anticipates discovering when the new meters are installed. There also will be some transitional costs during the first year to determine the best way to process false positive signals. After AMI installation is complete, SDG&E will require two additional agents to prosecute the large number of energy thefts we expect to uncover."[46]

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[45] *Meter Data Management System—What, Why, When, and How*, Hahn Tram and Chris Ash, System Engineer, Enspiria Solutions. August 29, 2005.

[46] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared

With comprehensive AMI/MDMS and vigorous meter revenue protection programs, the most likely outcome is that AMI will bring a reduction in non-technical losses due to theft.

Meter Reader Shortcomings

At the same time, it should be kept in mind that there is an existing level of theft occurring even with manual readers in the field. In some cases, field-level engineers have not been made responsible or accountable for the energy input to their areas, the energy billed, or the revenue. This inattentiveness contributes to non-technical losses.

The personnel best qualified to detect metering problems are often the ones responsible for the faulty metering installation in the first place. In some countries, meter technicians and readers are complicit in meter tampering and bypass.

Meter Defects

Real-time two-way communications offered by AMI allow a utility to detect meter defects that might degrade to failure before the utility could learn about them from manual meter reads at intervals that are often as long as six or twelve months. Furthermore, there is evidence that meter readers miss some amount of meter tampering.[47] There are instances when distribution utilities have discovered meter tampering when deploying AMI that had not been reported by meter readers.

Need for On-site Inspections Post-AMI Deployment

Periodic on-site visits by meter inspectors carefully trained to know what they are looking for are an essential tool in the detection of theft in a post-AMI environment. It is good practice to visit randomly and inspect meters on a recurring basis. Some utilities plan such inspections on a 5-year cycle.

Customers who engage in diversion activities usually act to prevent access for meter reading, and procedures to require and enforce inspection are essential. Traditional meter readers may not be trained for new, more creative methods of energy diversion and must be schooled to recognize the sophisticated tampering methods that may follow the deployment of AMI. In addition, it should be noted that with advanced metering technology, various system abnormalities can resemble power theft. Thus, the staff of revenue assurance departments must have a higher level of training, technical know-how, leadership, judgment, and inquisitiveness.[48]

Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

[47] In an extensive study undertaken in the Merseyside area over a five-year period, Revenue Protection staff acted as meter-reading staff and gained valuable intelligence. It became apparent that meter readers were poor at recording signs of interference with, say, only 1 in 15 of them providing reliable reports. *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

[48] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

The transformation from "meter reader" to "meter revenue protection agent" is a core change in the evolution from traditional meter reading to AMI.

> "The old-fashioned methods are dwindling."
> Ron Jones, Residential Meter Services Manager, JEA

Meter Readers

Meter readers read electric, gas, water, or steam consumption meters and record the volume used. They serve both residential and commercial consumers. The basic duty of a meter reader is to walk or drive along a route and read customers' consumption from a tracking device. Accuracy is the most important part of the job, as companies rely on readers to provide the information they need to bill their customers.

Other duties include inspecting the meters and their connections for any defects or damage, supplying repair and maintenance workers with the necessary information to fix damaged meters. They keep track of customers' average usage and record reasons for any extreme fluctuations in volume. Meter readers are constantly aware of any abnormal behavior or consumption that might indicate an unauthorized connection. They may turn on service for new occupants and turn off service for questionable behavior or nonpayment of charges.

Median annual earnings of utility meter readers in May 2006 were $30,330. The middle 50 percent earned between $23,580 and $39,320. The lowest 10 percent earned less than $18,970, and the highest 10 percent earned more than $49,150. Employee benefits vary greatly between companies and may not be offered for part-time workers. If uniforms are required. employers generally provide them or offer an allowance to purchase them.

Tasks

- Read electric, gas, water, or steam consumption meters and enter data in route books or hand-held computers.
- Walk or drive vehicles along established routes to take readings of meter dials.
- Upload into office computers all information collected on hand-held computers during meter rounds, or return route books or hand-hand computers to business offices so that data can be compiled.
- Verify readings in cases where consumption appears to be abnormal, and record possible reasons for fluctuations.
- Inspect meters for unauthorized connections, defects, and damage such as broken seals.
- Report to service departments any problems such as meter irregularities, damaged equipment, or impediments to meter access, including dogs.
- Answer customers' questions about services and charges, or direct them to customer service centers.
- Update client address and meter location information.
- Leave messages to arrange different times to read meters in cases in which meters are not accessible.
- Connect and disconnect utility services at specific locations.

Work Activities

- Documenting/Record Information—Entering, transcribing, recording, storing, or maintaining information in written or electronic/magnetic form.
- Collect Information—Observing, receiving, and otherwise obtaining information from all relevant sources.
- Communicate with Supervisors, Peers, or Subordinates—Providing information to supervisors, co-workers, and subordinates by telephone, in written form, e-mail, or in person.
- Process Information—Compiling coding, categorizing, calculating, tabulating, auditing, or verifying information or data.
- Work Directly with the Public—Dealing directly with the public. This includes contact with customers, representing the organization to customers, the public, government, and other external sources. Information can be exchanged in person, in writing, or by telephone or e-mail.

Bureau of Labor Statistics, U.S. Department of Labor, *Occupational Outlook Handbook*, 2008-09 Edition.

Revenue Protection: Transition from Traditional to AMI

The first step in transitioning from traditional meter reading to remote was AMR, which replaced meter readers with remote meter reading via one way communications. The primary driver for this was savings on meter readers. This introduced difficulties with respect to theft detection. These difficulties were overcome with the evolution from AMR to AMI. AMI, coupled with MDMS, offers considerable advantages with respect to theft detection and the reduction of non-technical losses.

When AMR was introduced, there was an expectation that revenue protection would benefit greatly, and the need for revenue protection analysts and investigators would be greatly diminished. Tamper flags would be the solution. This did not prove out during large-scale deployment. In fact, AMR produced a flood of tamper flags that had the practical effect of being impossible to manage and, thus, being ignored. Except now, the "eyes in the field" were gone.

Most AMR meters have revenue-protection-related features that are useful for detecting novice tamperers, such as reverse rotation (meter being inverted by the customer) and magnetic presence (external magnets placed on meter in an attempt to reduce its registration).

However, there are limitations to AMR's ability to detect theft by experienced or professional tamperers who seek to defeat the system by installing taps ahead of the meter (for example, masthead), limit the ability to detect "last gasp" while installing bypass behind the meter, or using conventional tactics to slow disk rotation on retrofitted meters. Of course, stolen meters placed in-service by customers are difficult to locate.

Tamper Flag Problem

Several companies that have installed large-scale AMR have experienced problems with tamper flags. AMR has functionality for determining valid flags, but AMR supplies more information than utilities are able to monitor. There are problems with tamper data because of volume and the number of variables that must be taken into account for validation and separating the "urgent" and "genuine" interference cases from false alarms and technical faults. Utilities had to develop their own algorithms for dealing with this.

Further, AMR is not able to cover the types of theft that tamper flags do not report. It cannot detect diversions where the meter is bypassed completely (by "tapping" into the cutout or the wiring from it ahead of the meter). There is no way of detecting this, other than from analysis of consumption. Additionally, AMR is not able to monitor consumption and detect abnormalities which might be due to theft.

The solution to this is offered by AMI and MDMS.

The limited benefit of AMR for theft detection and problems with tamper flags pointed toward the need for MDMS, which only really came into its own later, when AMI was introduced. The awareness of data management requirements, after the experiences with AMR, was a major developmental turning point in the evolution of AMI applications for theft detection and non-technical loss reduction.

AMI provides information for detecting certain kinds of losses, such as detecting recurring tampers from upside-down meters and dial tampering, site and installation diagnostic problems, consumption on inactive accounts, and detailed data for trends and comparisons. However, AMI offers little or no protection from "one-time tampers" (adjustment screws, register tampering, magnetic circuit alteration, electrical circuit alteration or alternations external to the meter, magnets, disk "pinning", stolen meters and, most obviously, taps and jumpers.) These can only be detected using customer modeling (MDMS) and other revenue assurance tools as part of pro-active revenue assurance programs and systems, staffed by well trained and knowledgeable people.[49]

AMI provides a valuable tool to help utilities reduce lost revenue in each one of these areas, but AMI "... is only a tool—it must be coupled with *systems, people, and experience*."[50]

The transition in the detection process from traditional to AMI is summarized in Table 2-1.

Table 2-1
Comparison of Detection Process

Comparison of Detection Process
Traditional vs. AMI

Detection Process		
Traditional	**AMI**	**Change**
Meter readers	Solid-state meters	Improved reading accuracy
Tips/utility hotline	Remote meter reading	Eliminates need for meter reader
Meter-reading reports	Two-way communications	Permits more frequent readings
Statistical analysis	Remote diagnostics	Discovers malfunctioning meters
Proactive sweeps	MDMS	Supports enhanced customer service
Collateral investigation	Meter revenue protection agents	Meter Audits

Transition to Revenue Assurance

In the 1970s and 1980s, these activities were called "current diversion." In the 1990s, they were called "revenue protection." Today, the preferred term is "revenue assurance." Revenue assurance conveys the full meaning of its role in a distribution utility, namely assuring that all the revenue owed the utility is collected.

Revenue assurance includes the following:

- Theft detection and follow-up
- Metering mistakes—for example, malfunctions, meter constants, and billing errors

[49] One study reported an average accuracy of 35% using AMI flags with consumer models. This is much better than AMI flags alone (4%) and better than customer models alone (29%) and is considered a very good "hit rate." *Revenue Protection and AMI Come Together*, Ed Malemezian. June 25, 2007.

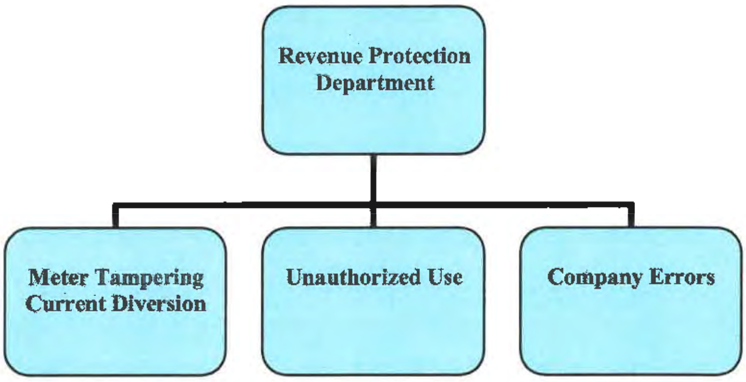
[50] *AMR Tamper Detection—The Good, the Bad, and the Possibilities*, Ed Malemezian

- Consumption on inactive accounts
- Collections

Revenue Protection Department

As revenue protection transitioned to revenue assurance, so did the responsible department and staff. The responsibilities remain the same, namely personnel training (mostly meter readers), receiving information on electricity theft from customers and staff, analyzing consumer load profiles for drastic changes compared to past trends, assessing charges for electricity theft and equipment tampering, and—if necessary—prosecuting clients who endanger themselves or field staff. The main source of information that utilities traditionally use to detect and prevent electricity theft is the meter-reading staff.

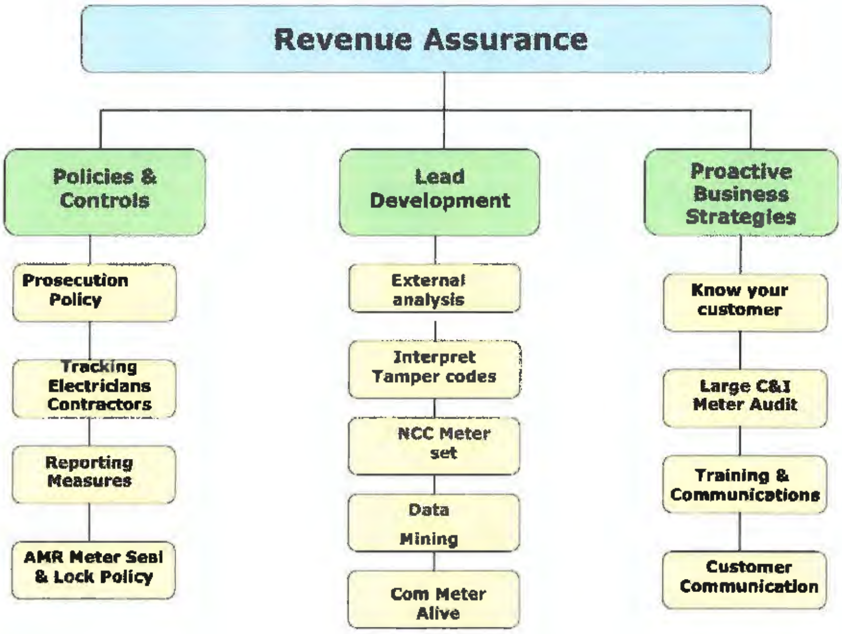
The traditional organization for discharging these responsibilities is illustrated in Figure 2-1. The three major areas where revenue (non-technical) losses were discovered by the Revenue Protection Department were meter tampering and current diversion, unauthorized use, and company errors.



Source: IURPA/WSUTA Conference, Las Vegas, Kurt W. Roussell, Revenue Protection, WEC.

Figure 2-1
Revenue Protection Department

Revenue assurance, on the other hand, is a term that describes the revenue security function as performed with AMI / MDMS. The new Revenue Assurance Department does not rely on manual meter readers—the "eyes in the field." Rather, there is a heavy reliance on policies and controls, lead development using analytical data and customer profiles, and proactive business strategies that include meter audits and customer communications. Meter readers are not absent from this department, but they are no longer depended on so extensively. Rather, revenue assurance with AMI relies heavily on MDMS, analytical tools, and analysts.
The organization of a typical Revenue Assurance Department under AMI is shown in Figure 2-2.



Source: NSTAR

Figure 2-2
Revenue Assurance

Revenue Protection Using AMI and MDMS

The AMI data collection front end detects and reports unexpected usage patterns. Typically, consumption profiles are established for each meter through automatic assignment of profiles using CIS supplied data and manually assigned profiles for specific or temporary situations. Each profile can consist of one or more checks. These checks can be enabled and disabled by the time of the year. They can be used to find diversions for monitoring seasonal meters. Drops in usage can be correlated by power outages for each meter as compared with other meters on the same transformer. All of the applicable checks need to be flexible enough to allow assignment of predetermined percentage changes in consumption, with day of the week and date range selection set up as required for each profile.

The Meter Data Management System (MDMS) receives additional information to aide in more filtering. Typically weather data, utility work order tickets, account status, and limited demographic data are brought in to aide in the filtering. Monthly and daily consumption data are collected and compared on a regular basis against profiles established for each customer. This data can be normalized by weather and other variable parameters. Effective usage is compared against baseline usage to generate candidate lists. These lists are then further filtered by additional information from tamper flags and more advanced consumption patterns to develop suspect lists. The suspect lists are organized and sent to the field for investigation. Various tools are often provided to drill down by customer and groups of customers.

The availability of interval data raises the bar to yet a higher level. Tools to compare actual interval usage against expected interval usage provide a much better picture in spotting the outliers. Advanced statistical techniques are used to generate appropriate algorithms that analyze the data. Science and art come together in making a success of this. Statistics also can be helpful in establishing confidence levels of the suspect lists, allowing the lists to be cranked up or down to match the availability of investigators to do the follow-up work.

Tests by transformer and geography provide another view of customer consumption patterns. When a utility utilizes account-to-transformer mapping, it allows the comparison of usage across similar homes served by the same transformer to look for low usage outliers, and to correlate changing usage patterns with blinks, reverse rotation, or other events. This mapping also enables comparison of transformer load to aggregated usage, if the utility installs additional interval meters upstream of the utility transformers. When meter data is supplemented with data from other sources, more views and points of comparison can be created. Examples include creative mining of other CIS fields such as the SIC Code or Customer Name to find groups of customers with similar names.

The Revenue Protection application receives all relevant data from the utility CIS, historical and present temperature data from an internet based source, triggered flags from the AMI tamper database, geographical information from external sources, SIC codes and NAIC codes from CIS, demographic data from paid or public sources, operating hours from public sources and feet-on-the-ground research, as well as daily and interval consumption data from the utility AMI or MDM systems.

Profiles and consumer models are built from sets of flexible rules. These are assigned to each account and analyzed on a regular basis. Tools include the ability to drill down by customer or group and to score each deviation from expected consumption patterns by numerous methods. Candidate lists and suspect lists are managed, and feedback is provided for both tracking results and improving the process.

Revenue Protection and AMI Come Together, Ed Malemezian. June 25, 2007.

MDMS Theft Reports

With the advancement of AMR/AMI, the traditional approach of identifying potential theft with a meter reader's visit to the site is becoming obsolete. Aided by MDMS, data analysis provides leads based on usage patterns and other data.[51] This is proving to be an effective approach to identifying theft.[52]

MDMS is used to turn AMI data into leads that can be followed up by revenue assurance teams. MDMS provides "automated exception processing" reports. An exception is when the system sees an event or data circumstance that it is not expecting. Examples with revenue-assurance relevance include meter readings that show lower consumption than expected, meters that do not report any consumption, and readings that show power being used at a supposedly vacant premise.

"Plus or minus 20" reports look at accounts where consumption has gone down by at least twenty percent. Data is reviewed over a thirteen-month period, ensuring that the information reflects seasonal usage patterns.

Another approach looks for unusual usage patterns, such as usage that drops off substantially on weekends. Through the MDMS, utility managers can compare unusual usage reports with power-outage and restoration reports that narrow down dead-end leads. This lowers the cost of collection.

Examples of Reports Using AMR/AMI Data[53]

- An "unplanned outage" report spotlights accounts with more than 10 outages in 30 days. About 40 percent of PECO's theft detection stems from this report.
- A "billing window" report detects meters turned on or off close to the billing period, indicating attempts to force low-balled estimates or pay for only a few days' worth of consumption. This report pinpoints around 35 percent of the utility's theft.
- A "reversed meter" report finds power-out and power-up messages that occur in quick succession if the customer unplugs the meter, then plugs it in upside down to make the register run backward. About 20 percent of PECO's theft shows up via this report.

[51] AMR / AMI tamper indications are analyzed with detailed consumption data, outage information, tickets from work order systems, and numerous external demographics. Advanced analytics are used to establish baseline patterns and profiles for customer accounts. Outliers can easily be identified and followed-up according to procedures established by the revenue assurance department.

[52] For example, at NSTAR, revenue protection billings increased more than 130 percent, while the cost per case processed decreased by 25 percent. The improvement was due to leveraging the lead generation partnership and streamlining the process with automated reports, fewer handoffs and triage of theft cases. *Reducing Revenue Leakage*, Penni McLean-Conner, NSTAR. Electric Light & Power, July 2007.

[53] *Deputizing Your Data: AMI for Revenue Protection*, Betsy Loeff, Electric Power and Light.

AMI Remote Service Disconnect

In certain instances, utilities incur losses when customers leave without disconnecting. In these cases, the utility has active accounts without contracts. Oftentimes, it would take utilities a minimum of thirty days to find active accounts with no contract. This produces non-technical losses.

With AMI, service cut-offs can be "virtual," without dispatching a field service technician to the site. Instead, the utility takes a reading through the AMI system, sends a final bill to the departing customer, and leaves the premises ready for the next resident.

Sometimes the new resident does not call to set up an account after moving into a house or apartment. In these instances, a consumption threshold is set up. Once the threshold is surpassed, the MDMS automatically generates an order for a field service technician to shut off service.

Key Attributes for Revenue Protection—AMI + MDMS

Advanced Meter Infrastructure

- Full two-way communications
- Advanced meter capabilities with extensive diagnostics
- Exponential increase in meter reads and meter data
  Example (500,000 meters):
  1 monthly read = 500,000 reads/month
  1 daily read 500,000 reads/day, 15 million reads/month
  1 hourly read 12M reads/day, 360 million reads/month

Meter Data Management Systems

- Systems to create reports that analysts/investigators can use to research, investigate, and take corrective action
- Energy Diversion will become more innovative with smart metering (without manual meter reading). Data and analytical tools must be used to "outsmart the thieves"

Pros

- Better knowledge of unbilled revenues
- Notification of illegal reconnects
- Ability to examine consumption patterns from daily read information
- Ability to examine 15-minute interval data

Cons

- Loss of regular field visits to examine metering equipment
- Inability to determine connections ahead of the metering scheme
- The meter will tell you only what it sees—not what it doesn't see
- Unless additional services are known, unmetered (unbilled) revenue can occur for years
- The combination of these factors along with the rising cost of energy increases the potential for revenue loss significantly

Source: *Various Applications of Electric Metering & How They Relate to Revenue Protection*, Guy Cattaruzza United Illuminating NURPA. September 19, 2007.

Billing and Customer Service

Along with theft, the billing and customer service problems encountered by traditional manual meter-reading operations are contributors to non-technical losses.

Traditional Billing System[54]

Currently, meter readers travel to customers' meters each month to collect customer usage information (meter reads) with a hand-held data collection device.

These meter reads are used to prepare monthly bills. After the meter-reading route is completed, the customer's meter reads are transferred from the hand-held device to the customer information system. This data transfer must be done at a meter-reading base location. Back-office billing systems then perform a series of data validation routines that will, if warranted, automatically trigger a pre-billing review that may result in bill adjustments. The largest number of bill adjustments is due to meter-reading error.

When customers move from one residence or business to another, field service personnel must visit the meter and complete a "close order" or a "change of account" order to obtain the "end read" for the departing customer and a "start read" for the new customer. A certain number of these orders are "revert to owner" reads where service is left on for the convenience of property owners or managers when a tenant moves. Also, when meter-reading errors are suspected, field service must perform a "read verify" order at the customer's meter.

Billing System with AMI

AMI eliminates field visits as part of the billing process. Instead, utilities obtain meter reads electronically on the date a customer desires rather than on a service order schedule, which is subject to delay due to workload constraints. This reduces error and, thus, non-technical losses. It also improves customer service.

To prevent billing errors, once meter data is captured the billing system performs a series of billing edits prior to sending the customer bill. Despite comprehensive edits, some billing adjustments are required after bills have been sent. Other anomalies (billing exceptions) also are detected after completion of the billing cycle, such as meters in "off" status but registering consumption (OBR), meter failures, and unauthorized energy usage theft. With AMI, many of these billing exceptions will be eliminated and others will be detected more quickly, thus reducing non-technical losses.

Estimating

Estimating is one of the defining issues for which AMI offers a solution and contributes to the reduction of non-technical losses.

[54] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection,* Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

The vast majority of utility customers receive a monthly visit from their utility's meter reader. This meter reader visually reads the electric and/or gas meter, then forwards that information to the utility's billing office to generate a monthly consumption bill. If the meter reader is unable to access the meter,[55] most utilities will proceed to estimate the electricity consumption based on previous usage and recent weather patterns. They will then use that estimate as the basis for the next bill.

Exception reports are another area where estimates are made. After data are collected, they are analyzed, looking for exceptions such as missing reads, zero consumption, idle with consumption, out of range readings, and negative consumption. These transactions are placed in an exception file for review. Actions taken by revenue protection to correct the exceptions include reading, re-reading, checking for malfunction, checking for tampering, or accepting the read and estimates.

It is not uncommon for utilities—particularly those in higher-density urban areas—to estimate ten percent, twenty percent, even thirty percent or more of the meter reads each month for billing purposes. This practice leads to inaccurate billing, increased customer complaints, and higher costs for utilities to investigate and resolve those complaints.

AMI Solution to Estimating

AMI provides accurate, timely, and reliable information about energy use and demand that offers a solution for estimating.

AMI minimizes meter access problems, limiting them to meter installation and inspection upon suspicion of tampering or diversion. AMI eliminates estimated reads and improves meter-reading accuracy, which results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.[56] Further, AMI reads remotely interrogate meters daily, rather than monthly. This identifies bad meters more quickly and avoids much of the estimating.

Thus, AMI offers a solution to estimating, which contributes to the reduction of non-technical losses.

Security

AMI avoids the security risk of giving keys and access to premises to meter readers. This is a concern of high importance in these security conscious times.

[55] A meter cannot be read when it is located in the basement and the consumer is not home; the yard is fenced with a locked gate and a dangerous animal in the yard; customers are threatening or hostile; extreme weather; or when the meter is dead, damaged, or missing.

[56] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency,* A Report to the U.S. Department of Energy, Itron. October 2005.

AMI + MDMS Solution: Importance of Information Technology

A comprehensive revenue assurance program is based on AMI and MDMS.

This constitutes a "holistic approach to revenue recovery"[57] that combines expert analytical resources, data analysis software, internal utility customer asset data, and external data sources. This involves identifying data flow requirements and providing solutions to ensure timely and accurate billing. This requires the effective integration of AMI and MDMS with existing data systems in the utility.

Information Technology Integration

IT integration is a major participant in the transition from traditional meter reading and revenue protection methods to AMI and comprehensive revenue assurance programs. It's importance is underscored by the level of investment in most AMI programs. Indeed, back-room office applications are a large portion of the total AMI investment, ranging from a low of 5% to over 30%. IT integration is essential to the management and reduction of non-technical losses after the transition to AMI.

IT heavily influences the success of the AMI program and the integration of information systems using new MDMS that is essential for the success of the AMI program. The IT integration plan includes five major systems:

1. Meter Reading
2. Meter Inventory Management
3. Work Order Management
4. Customer Information
5. Revenue Assurance

Integrating these systems is a substantial and complicated task. This requires a high level of commitment from IT stakeholders.

When AMR systems were installed, primarily for savings in manual meter reading, IT integration was not a priority. However, when the data flows (such as tamper flags) became overwhelming, utilities needed applications to manage them. These were often provided through *ad hoc* custom programs developed internally by IT departments.

For this reason, it is advisable to include IT stakeholders from the beginning when making the transition to AMI. The commitment should be in terms of the project, resources, change management, and setting expectations for results. Commitment from IT stakeholders dramatically affects the success of the transition and results in reducing non-technical losses, both at the time of installation and throughout project life.

[57] *Discovering Unaccounted-for Energy with the Revenue Assurance Service*, Patty Seifert, Revenue Assurance Product Manager, Itron. 2007.

Revenue Assurance and IT Integration

The advent of AMI brings a total change to the conduct of revenue protection. If not preceded by AMR, the most obvious change is the elimination of manual meter reading as the primary method of data collection on meter tampering and theft.

Without the benefits of manual meter readers, revenue protection must supplement AMR/AMI with meter data management systems to compensate for the loss of functionality previously provided by meter readers. This involves integrating MDMS into the customer information system. The combination of data from AMR/AMI, MDMS, and customer information system (CIS) can be used to generate leads and profiles for target areas and customers.

Revenue Assurance, Metering & IT business units must come together early, prior to the deployment of AMI, to form a team separate from the deployment itself to develop a Revenue Assurance Transition Plan.

Transition to AMI—Information Technology
Issues that Impact Revenue Protection

- System reliability, data backup and disaster recovery
- Reporting / monitoring capabilities
- End of day vs. real-time 24/7
- Exception handling
- Secure access
- Customer information system integration
- Work order file definitions
- Customer data file management
- Meter reading / billing window ("blackout")
- Test and validation of upload/download processes
- Meter-reading systems integration
- Migration path
- Project size, schedule,and budget

Bob Donaldson, PE, PMP Progress Energy Carolinas Project Manager, Mobile Meter Reading.

Theft and Enforcement

New Methods of Theft

A major risk of realizing the full benefits of AMI for revenue protection is posed when customers learn to divert energy in new, unknown ways. Given historical data from AMR installations, this risk does not appear too great. Also, AMI endpoints have software and tamper sensors that are more sophisticated at detecting theft. Enhancements to back-office systems with new algorithms and heuristics to identify new types of theft are continuously being developed. Nonetheless, most certainly the ingenuity of a few customers will lead to some new types of theft. Distribution utilities need to be alert to new possibilities for theft and take them into account in their revenue protection strategies.

"The western countries and India have treated this as a criminal offence. But crooks always have the ability to keep one step ahead of the theft detection system. They stay in business purely through their flair to overcome any challenge that comes their way. They will find ways to be ahead of any anti-power theft detection system and will try to hoodwink the vigilance wing. Gone are the days of crude mechanical ways to tamper with the meter or divert electricity from main line. The R&D of electricity theft is moving faster than that of the best metering mechanisms, which was revolutionized with the advent of ICs and programmable logic circuits. Sharp minds frame laws and invent technologies; sharper minds find loopholes in it. Now power theft using the remote sensing devices, tampering of crystal frequency of integrated circuits; theft using harmonics, etc. have been developed."[58]

Customer Perception and Motivation

Far from deterring customers from theft, some distribution utilities have reported an increase in occurrences after AMI installation. Once some customers are aware that meter readers are no longer calling, they think that there is less likelihood of being caught. The technical aspects of dealing with advanced electronic metering are no deterrent. There is a wealth of data available on the internet on how to interfere with meters. Even consumption monitoring is not the full answer. Clever thieves know that they should gradually reduce consumption over a period to avoid detection by the relevant "filters."[59]

One new class of customers that are wittier than thieves in the past and have new motivations are "grow operations." These customers—the illegal growers—are motivated not by saving on electricity, but by not being detected as customers. This is a major source of non-technical revenue loss in Canada and parts of California.

AMI can be helpful in detecting theft by this new class of customer. An example from Sacramento, California, is noted in the following quotation.

"Energy theft is not high at all, but we have experienced a significant number of 'grow houses' springing up in the area. We see AMI assisting us in finding these houses from a transformer load perspective—it will tell us that we're sending out X amount of kWh and only billing for Y amount, and alert us to a potential problem."[60]

AMI systems that are deployed at the substation transformer and feeder level are particularly effective in detecting these thefts.

Enforcement

As the attention of regulatory bodies and the public is drawn to energy theft, new and better methods for detecting and finding instances of theft will be called for. AMI has much to

[58] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

[59] OFGEM *Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association*, Version 3 (final). March 15, 2006.

[60] Erik Krause AMI project manager, SMUD

contribute to these methods. AMI offers significant tools to expedite both discovery and resolution of theft cases. It can be used to build intelligent databases for identifying trends and potential factors influencing future theft strategies and targets. This is an ongoing endeavor.

AMI makes more aggressive enforcement programs possible by 1) identifying high-probability targets for investigation and 2) gathering more evidence and constructing more convincing cases.

Meter bypassing can be proved only when it is observed at the time of inspection. The consumer can erase all traces of theft if the inspection is known in advance. This is a significant problem in many developing countries. AMI can help identify customers and locations with a high probability of meter tampering and diversion, thereby increasing the chances to observe theft.

Investigating Power Theft

Utilities often initiate probable cause investigations after a meter reader detects a broken seal or other indications of tampering. The meter reader reports the condition to a supervisor or power theft investigator, who then conducts the investigation. At this point, some utilities will contact their local law enforcement agency and an officer will accompany the utility investigator during the initial investigation.[61]

If the investigator finds evidence of tampering, evidence is collected and reports are prepared. The utility maintains the evidence and provides supporting documentation.

Evidence and Prosecution

Before a utility can file charges against a potential suspect, it must gather the following as evidence, documents, and appropriate statements:

- Tampering devices—These could include straps behind the meter, wires used in a bypass system, or other tampering devices or equipment relevant to the case.
- Meter report—This report shows that the meter was operating correctly when installed and demonstrates how the particular tampering method used would have affected the metering of electricity.
- Witnesses—These are witnesses who provide testimony. They include the meter reader who initially detected the possible diversion, the utility investigator, and the police officer who conducted the investigation.
- Account billing history—This report illustrates the time the theft began and the amount and cost of the stolen electricity.

Without manual meter reading and field service personnel, AMI and MDMS are now expected to provide much of the required documentation for theft investigations. With AMI, this documentation can be much more detailed and present more persuasive cases. For example, most utilities have account billing histories on each account's consumption and billing records on

[61] *Power Theft: The Silent Crime*, Karl A. Seger, and David J. Icove, FBI Law Enforcement Bulletin, March 1988.

a month-by-month basis. AMI provides information on a daily and hourly basis. This is necessary to detect more sophisticated theft techniques, such as "on offs" during the day.

The burden of this documentation is one reason that utilities prosecute only about 10% of cases.[62] The burden can be lessened considerably by using the data that AMI generates and the ability of MDMS to organize it into useable formats for preparing complaints for use by prosecution.

Installation Effect

AMI deployment requires replacing legacy meters with new meters that include two-way communications and diagnostic capabilities. This is a one-time opportunity to significantly reduce non-technical losses due to meter defects, theft, and billing.

> "AMI provides the opportunity for a 100% clean sweep."
>
> Ed Malemezian

Meter Defects

Although theft is a major source of non-technical losses, a significant percentage of non-technical losses arise from factors that utilities can control, especially those related to meter damage, failure, and errors.

"Although, numerous published papers imply that all revenue losses are a result of customer mischief, this is far from true. This project found that, at least in the small industrial and commercial sector, utility operations themselves are responsible for the larger share of lost revenue. Equipment failure, non-malicious equipment damage, incorrect meter constants or 'CT' ratios, meters in need of recalibration, etc. all contribute to revenue loss."[63]

These are largely due to problems with maintenance issues of electromechanical meters nearing the end of their useful life and the tendency of electromechanical meters to run slower as they age. The replacement of legacy electromechanical meters with electronic metering, as part of AMI deployments, should substantially mitigate this source of loss.

The installation of AMI itself, and the replacement of obsolete meters, will contribute greatly to the discovery and remedy of this source of non-technical loss.

A large proportion of meter problems, and nearly all of the failures, will be remedied by a competent AMI deployment that re-installs all meters. Finally, for the life of the AMI system, the AMI-equipped meters will detect and report many types of energy diversion and meter tampering.

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[62] Ed Holmes, Senior Consultant, Arnett Industries.

[63] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Some existing meters may be within the permitted accuracy tolerances and still under-register consumption. This is so small that it is not cost-effective to change the meters on an exception basis. However, the AMI deployment replaces every meter anyway, and brings aggregate meter plant accuracy very close to 100%. This benefit will be long-standing because solid state meters have no mechanical wear or friction and do not slow down over time. Sometimes dead meters are found during meter replacements. "Dead meters" are not caught by "no consumption" reports because they usually occur on the percentage of meters that are not yet converted to automated metering.

Inspection

A full AMI deployment provides the opportunity to inspect, find, and correct tampering that has been in place for a long time—100% inspection. However, to be effective, AMR installers must be properly trained and incentivized to take the time required to discover, record, and report tampering.

The entire service entrance facility, not only meters, must be inspected. The importance of inspection to the reduction of non-technical losses is shown in the following statement.

"Utilities that take the time to thoroughly inspect the entire service entrance facility, as well as the meter and meter socket themselves, at the time of AMI equipment installation have the opportunity to minimize otherwise lost revenues."[64]

Some methods of energy theft, such as meter bypass, meters turned upside-down, and meters with drilled holes or adjusted dials, are not necessarily seen by meter readers during their monthly meter-reading cycle visits. Since AMI offers total meter replacement, almost all simple energy theft will be uncovered during the installation of the new meters.

Meter Change-outs

As the volume of AMI-related meter change-outs increases, timely synchronization of meter changes with customer account data becomes essential to help a utility avoid large numbers of billing system rejections caused by incorrect meter assignments. MDMS helps to minimize the number of incorrect and estimated bills that result from the change-out process, thus avoiding billing errors that can contribute to non-technical losses during AMI deployment.[65]

Billing Transition Period

When new meters are installed, a number of data elements must be recorded properly to set up the billing systems. Additionally, new data about meter communications are typically required (such as AMI communication module serial numbers). The installation of AMI offers the opportunity to consolidate databases from multiple sources into a fully integrated MDMS.

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[64] Interview with Ed Holmes.

[65] This is particularly important with large-scale AMI deployments that can take from three to five years.

MDMS provides benefits to utilities during AMI implementation by helping to identify and track meter installation problems and verify that data received from endpoints is sufficient for customer billing. If installed as part of the AMI meter installation, MDMS can be used to process data for billing. MDMS can be used for validation, estimation, and editing in the billing process during installation. Interval data provided by AMI systems may have gaps and/or errors. The MDMS system can be used to fill in the gaps and correct the errors in the data.

The AMI installation period offers an opportunity to create customer profiles that compare usage patterns before and after AMI installation. The identification of possible theft in the past is an indicator of theft likelihood in the future.

GIS Mapping

AMI requires that meter asset data is maintained timely and accurately. Meter asset data, including meters and communication modules, must track assets from acquisition to inventory to field installation and provide accurate meter-to-customer and meter-to-network connectivity information. This often requires consolidating and enhancing existing meter applications, including those in meter test, inventory, AM/FM/GIS, and customer information systems. These issues must be addressed at the time the AMI system is installed.

Geographic information system (GIS) mapping during AMI installation provides a valuable resource for revenue assurance. AMI installation offers an opportunity to integrate a GIS system with the customer billing system. This is an effective tool for detecting theft at consumer, distribution transformer, and feeder or substation levels. Analysis of patterns of individual consumption over GIS can help in identifying the sources of theft.

Energy Diversion Program

Utilities can take advantage of the replacement of meters to refresh their energy diversion programs, as well as public awareness of the issues and penalties.

Distribution utilities that have some type of revenue protection program in place can update their program and institute more aggressive programs using a combination of the AMI, MDMS, and teams of newly trained field inspectors.

For distribution utilities that do not have an energy diversion program, AMI installation is an opportunity to institute one at low cost.

AMI Planning and Transition

The revenue protection department staff should be included in the AMI project team from the beginning of the planning process. These individuals can offer valuable insight on many pertinent issues, ranging from a customer's behavior to billing (the integration of databases in the MDMS) to collection. Most importantly, they have the experience to help train meter installation teams and monitor the testing and installation of the meters themselves. They are an important part of the transition to AMI. Their participation can contribute greatly to the realization of potential savings from AMI and the reduction of non-technical losses.

The transition itself—replacement of meters, analyzing customer profiles, testing, system development, algorithm development, and customer profiling—probably has the greatest impact on revenue security and the reduction of non-technical losses.

3
CHAPTER 3

AMI Technologies to Detect Non-Technical Losses

AMI offers many technologies for the detection and reduction of non-technical losses. These technologies can be divided into two main categories, hardware and software, as outlined in the following insert.

Hardware – metering technology

- Meter accuracy
- Tamper detection
- Remote testing diagnostics
- Remote connect/disconnect

Software-based applications and tools

- Meter data management systems
- Statistical analysis
- Geographical information systems

These technologies can be used alone or, preferably, in combination with one another for enhanced effectiveness and manageability.

In this chapter, these technologies will be discussed in the context of their relevance to non-technical losses.

Importance of AMI Technologies to Detect and Reduce Non-Technical Losses

The relevance of the technologies for the detection and reduction of non-technical losses is evidenced by the functions and uses that utilities consider most important as part of overall AMI deployment.

As part of the FERC report[66] on demand/response and advanced metering, FERC staff conducted a survey of utilities.[67] Respondents were asked how they used their systems and which functions

[66] Section 1252 (e) (3) of the Energy Policy Act of 2005 (EPAct 2005) requires FERC to prepare a report by appropriate region that assesses electric demand/response resources.

[67] *Assessment of Demand Response and Advanced Metering Staff Report*, Docket AD06-2-000. FERC. August 2006. In preparing this report, Commission staff developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering

are provided by the AMI systems. Specifically, the FERC survey asked organizations that have installed AMI systems[68] to identify which of the following possible AMI features they used:

- Remotely change metering parameters
- Outage management
- Pre-pay metering
- Remote connect/disconnect
- Load forecasting
- Reduce line losses
- Price responsive demand/response
- Enhanced customer service
- Asset management, including transformer sizing
- Premise device/load control interface or capability
- Interface with water or gas meters
- Pricing event notification capability
- Power quality monitoring
- Tamper detection
- Other

The most often reported functions were "enhanced customer service," and "tamper detection." Figure 3-1 shows the results of the FERC Survey.

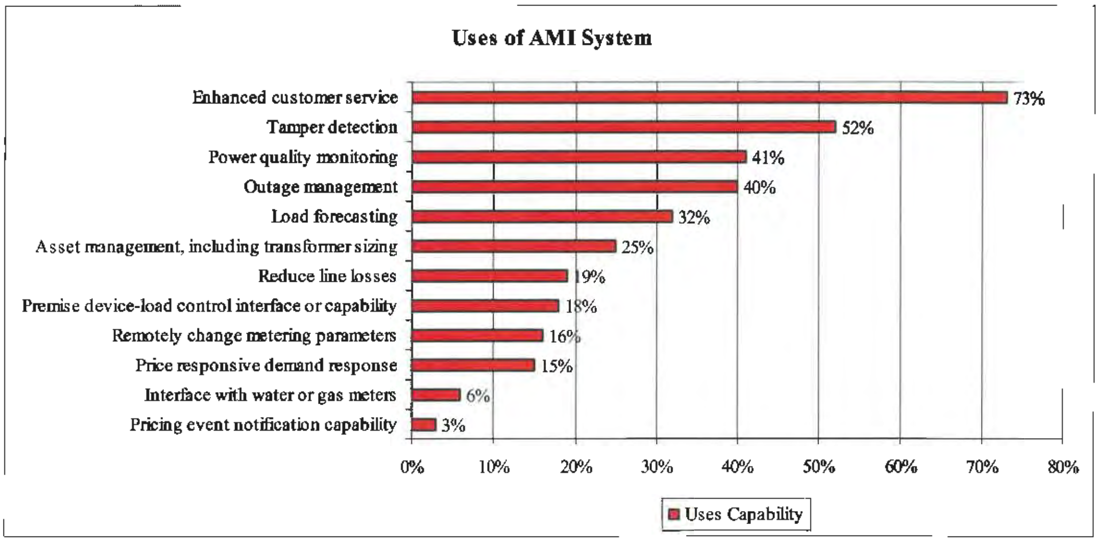

Figure 3-1
Uses of AMI System

Survey (FERC Survey) requested information on a) the number and uses of advanced metering and b) existing demand/response and time-based rate programs, including their current level of resource contribution.

[68] For purposes of this report, Commission staff defined "advanced metering" as follows: "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

The identification of these uses of advanced metering by utilities points to a number of areas related to the detection and reduction of non-technical losses. Recognition of these functions indicates the importance of non-technical losses to utilities as part of overall AMI programs. At minimum, it shows that AMI must deliver enhanced customer service and tamper detection:

Enhanced Customer Service: The ability to offer ultimate customers the choice of bill data, additional rate options such as real time pricing or critical peak pricing, verification of an outage or restoration of service following an outage, more information to address a customer concern over an electric bill, reduced bill estimates when a meter read is not available, opening or closing of an account due to customer relocation without requiring a site visit to the meter(s), and/or more accurate bills.[69]

Tamper Detection: The ability to detect the possibility that a revenue or billing meter has been tampered with, and to indicate a potential energy theft in progress, to be further investigated by the utility.

Theft at the Meter

There are two types of theft at the meter that contribute to non-technical losses: bypassing the meter and tampering with the meter itself.[70] The various ways in which this theft is done are listed in the following two inserts.

Installation Tampering

Line-side taps
- Weather-head
- Service entrance conductors
- Underground
- Switchgear / buswork / troughs

Bypass
- Jumpers in meter socket
- Close bypass device

Instrument transformer installations
- "Re-wiring"
- Shorting of current transformers

Meter Tampering

Internal to the meter
- Adjustment screws—one time
- Register tampering
- Magnetic circuit alteration
- Electrical alteration
- Dial tampering—Recurring

External to the meter
- Magnets—RC
- Hole in cover / disk "pinning"
- Upside-down meter
- Stolen meter

Internal physical tampering with the meter itself appears to be a less popular method of stealing energy than bypassing the meter or using diversionary taps installed ahead of the meter in the supply wiring.[71]

[69] AMI—through remote reading—allows for faster, more accurate accounts, reduces discrepancies, and through remote connect/disconnect allows for faster, more timely activation and deactivation of accounts. This translates to more revenue and fewer disputes.

[70] AMR Tamper Detection - The Good, the Bad, and the Possibilities, Ed Malemezian

Installation tampering and meter tampering should be kept in mind while considering the technology features described in this chapter.

Technologies

The uses of AMI technologies to support revenue assurance programs were discussed in the previous chapter. In this chapter, we shall focus on describing the technologies in terms of their characteristics and functionality.

Meter Features

Among the meter features used in AMI systems, those that are important for detecting non-technical losses are listed in the following insert.

[71] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Meter Standards and Features

Important for Detecting Non-technical Losses

Institute of Electrical and Electronics Engineers (IEEE)/ American National Standards Institute (ANSI) Standards

- IEEE 1701/ANSI C12.18 (1996)
  Protocol Specification for ANSI Type 2 Optical Port
- IEEE 1377/ANSI C12.19 (1997)
  Utility Industry End Device Data Tables
- IEEE 1702/ANSI C12.22 (1999)
  Protocol Specifications for Telephone Modem Communications

High-accuracy internal clock

Communications

- two-way communications
- communications functions that can be installed without disturbing metrology

Measurements

- power quality measurements: outage detection and duration; phase loss, sag, and surge detection
- storage capabilities for multiple sets of readings
- event log with circular memory buffer to store up to 100 events
- measure and display active energy delivered, received or net, or any two registers from delivered, received and net (kWh and kVAH)

Prepayment

- prepay functionality, including varying deductions per time-of-use scheduling, configurable emergency credit, and audible low-credit alarm

Security

- measurement technology that is immune to magnetic tampering
- record of programming changes, power outages, number of demand resets
- reverse disk rotation

Disconnect/connect

- disconnect switch controlled via software
- remote disconnect/reconnect switch

Tamper Detection

- tamper indications that can be communicated regularly through the communications system
- indicators include meter inversion, meter removal, and reverse energy flow
- tamper-resistance features that measure energy even if the meter is inverted and detecting when the meter is removed from a live socket
- increments a counter each time the meter senses reverse power flow
- power removal tamper (increments a counter each time the meter is removed from a live socket)

Hardware: Meter Requirements

Meter requirements will be discussed under four major headings:

1. Meter accuracy
2. Tamper detection
3. Remote testing and diagnostics
4. Remote disconnect / connect

Meter Accuracy

The accuracy of metering data is becoming increasingly important as advanced metering provides data that are integrated across many utility functions. The trend towards solid-state meters capable of delivering information for real-time use has increased both the visibility and importance of meter accuracy to distribution utilities, customers, and regulators. The increasing inaccuracy of legacy electromechanical meters as they age contributes to non-technical losses.

To evaluate the best metering platform for AMI, one utility performed a statistical study of electromechanical meter accuracy.[72] The results were as follows:

1. A thorough statistical analysis of electromechanical meter accuracy found that 20% of electromechanical meters have a high likelihood of under-recording usage by an average of nearly -0.8% (or 99.2% meter accuracy), with significant levels of variability in meter accuracy.
2. Service location (environmental factors), manufacturer meter serial number, and meter age were found to be reliable predictive factors of electromechanical meter accuracy.
3. The "accurate life" is about 25 years for most electromechanical residential meters and about 20 years for most electromechanical demand meters.
4. The volume of in-service meters recommended for replacement was highest for meters purchased from the late-1970s to the mid-1980s. Over 32,000 in-service meters recommended for replacement had an unknown purchase year and an average kWh composite meter error of -1.13%.

Meter Accuracy

Mechanical meters, in addition to being less accurate than solid-state electronic meters when new, fail as they age. Many meters eventually fail completely and register zero-use. Such failures often go undetected for a period of time because they are assumed to be caused by customer vacancy. Eliminating slow meters and other metering issues involving "lost and unaccounted for" energy use will result in accurate bills and assign payment obligations to those customers who use the energy rather than to all other customers.

Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, SGD&E before the CPUC, March 28, 2006.

[72] *Metering Accuracy, Solid State Metering and the Electric Utility Enterprise Transformation,* Dave Mundorff, Entergy Corporation. September, 2005.

Tamper Detection

Tamper detection features that are important to AMI include the following:

- Reverse energy flag / reverse energy register
- Tilt switch
- Meter inversion
- Blink counter—no power to meter
- Magnetic sensors and diagnostics

These tamper detection features are described in the sections below.

Reverse Energy Flags
Reverse energy flags detect meters that have been turned upside down. In addition to the flag, some meters capture the reverse energy in a separate register. Other meters simply add reverse energy to forward energy, thereby accumulating total consumed. Theft is detected when the total no longer matches the meter dials.

Tilt Switches
Tilt switches detect meters that have been tilted from the normal position, usually around 50° to 70°. Tilt switches are prone to give false indications from vibrations. Meter removal is inferred when the tilt switch closes and a power outage detected after short time delay. Tilt switches, along with the outage detection, provide a reliable indication of meter removal. However, it must be noted that meter removal does not necessarily mean that tampering has taken place.

Meter Inversion
Meter inversion is inferred when meter removal has been detected.[73] In this instance, the tilt switch stays closed and power is restored, providing a reliable indication that the meter is running upside down. This also can generate a reverse energy flag.

Blink Counters
Blink counters measure increments for each interruption detected. A repeated number of interruptions can indicate tampering.

Magnetic Sensors & Diagnostics
Site and meter diagnostic sensors on solid-state meters (solid-state meters only; not meters with communication interface add-ons) detect meter wiring, instrument transformer, voltage, and current balance problems. Meter diagnostic flags detect internal meter malfunctions and tampering.

Reverse energy flags have proved effective in tamper detection. However, AMI generates a very large number of flags that must be sorted out. In many cases, the number of flags is overwhelming. Some of the flags are "false;" for example, magnet sensors generate many false flags.

[73] When the meter is pulled out of the socket and plugged back in upside down, the meter runs backwards and the kWh register goes down instead of up. The user leaves the meter inverted for a number of days to shave usage off the bill, and the meter is then reinstalled before a meter reading.

To be effective, tamper indicators must be filtered to spot trends and provide reliable comparisons.[74] Blink counts and outage flags must be compared against neighbors. Regular meter work, emergency work, maintenance, and repair work must be backed out of data on meter tilts, removals, and power outages. In other words, a system solution is required for these features to be utilized effectively by revenue protection departments.

Tamper Detection Features

Meters shall be able to:

- detect removal from its socket and generate a tamper event before it loses ability to communicate with the communications network
- detect voltage at the load side when the disconnect switch in the meter is open (for the purpose of detecting meter bypass) and generate a tamper event
- detect physical inversion and generate a tamper event
- detect physical tampering, such as, seal tampering, meter ring removal, case / cover removal, etc. and generate a tamper event
- transmit and locally log the following information (at a minimum) for each tamper event:
    1. Event Timestamp
    2. Tamper status (event type)
    3. Meter ID
- communicate tamper events to the Data Center Aggregator as soon as they occur (when possible)
- send meter tamper events with a higher priority than normal status messages
- store tamper events and transmit them when meter communications are re-established (if the meter is unable to communicate at the time the tamper event is detected)
- distinguish initial installation events and re-energize events (i.e. after an outage) from meter removal and reinstallation (potential tampering) to avoid transmission of non tamper related events.
- store tamper events until they are flagged for deletion once they have been successfully transferred to the Data Center Aggregator and 45 days have passed.

AMI Preliminary System Requirements, SCE. June 2006.

Testing and Diagnostics

Since AMI systems allow the reduction or elimination of meter service personnel and on-site visits, remote diagnostics are used to replace the meter reader's "eyes in the field."

Diagnostic features located in the meter typically provide measurements of parameters such as the following:

- Polarity
- Voltage deviation

[74] AMR Tamper Detection—The Good, the Bad, and the Possibilities, Ed Malemezian

- Inactive phase current
- Phase angle displacement
- Current imbalance
- Reverse energy

Service scan diagnostics read data on these parameters and current conditions at meter locations.

Results are reviewed by engineering staff who initiate an investigation, issue an instruction for meter change-out, or an investigation of the distribution line.

Service scans can discover open voltage test switches, current test switches left shorted, failed wiring on the meter harness from test switch to meter base or incorrect initial wiring, failed voltage transformers, and open distribution line fuses. All of these, including meter failure itself, contribute to non-technical losses.

The requirements for testing and diagnostics for meters and data center aggregators are shown in the following insert.

Testing and Diagnostics

Meter shall be able to:

- support a remotely or locally initiated meter test for communications connection status
- support a remotely or locally initiated meter test for energized status
- support a remotely or locally initiated meter test for load side voltage
- support a remotely or locally initiated meter test for disconnect switch status
- support a remotely or locally initiated meter test for internal clock time accuracy
- return results for all remote or local meter tests within 60 seconds
- Neighborhood Aggregator shall permit remote:

  1. status report (up / down)
  2. diagnostics
  3. link status report
  4. communications event log retrieval

Data Center Aggregator shall be able to:

- provide comprehensive remote testing and diagnostic capabilities for each system component (communications and meters) based on a (periodic) schedule or on demand. Remote testing and diagnostic alarm messages are to be considered high priority.
- remotely test meters for communications status, energized status, load side voltage and switch status on-demand.
- remotely test communications with external third parties.
- identify the probable cause of a communications failure within the AMI communications network.
- provide mechanisms for remotely correcting system/component problems, which at a minimum shall include the ability to remotely recycle (or restart) a component.
- log the results of all remote testing and diagnostics activities and any automatic actions taken based on those results.
- make the results of all received alerts and remote testing and diagnostic results available to authorized IT systems (e.g. MDMS, CSS, Work Order Tracking, etc.).
- have configurable alert levels and notifications based on the severity of a problem detected and the number of endpoints affected.
- classify specific testing/diagnostic results to either require or not require human intervention (configurable) in the determination of issuing trouble reports.
- detect if any network components are not responding within the following intervals based on the number of meters affected. (Estimate only; different network topologies will result in different values.)

  A) < 200 meters - next read.
  B) 200 - 1000 meters - within 6 hours
  C) 1000 - 5000 meters - within 1 hour
  D) 5k - 20k meters - within 15 minutes
  E) 20k - 50k meters - within 1 minute

AMI Preliminary System Requirements, SCE. June 2006.

Remote Disconnect / Connect

With solid-state meters being deployed as part of AMI systems over entire service territories, remote connect/disconnect features are attractive from service, operational, and economic points of view. The key driver for this change is that meter providers can integrate the disconnect/connect switch into the solid-state meter.

Remote connect/disconnect switches have traditionally been installed on electric meters for customers who either were consistently late on paying their electric bill or that lived in an area where people moved more frequently.[75] These classes of customers have a high incidence of non-technical losses with respect to non-payment of bills and errors in billing due to timing of disconnects / connects (stop time for one customer; start time for another).

[75] This is not an insignificant class of customer. For example, customers in SCE's service territory move at a rate of one in every four customers per year. (Paul DeMartini, Director AMI Program)

Remote Connect/Disconnect Features

Meter shall be able to:

- accept scheduled service disconnect/ reconnect
- remotely disconnect/ reconnect on demand
- remotely disconnect/reconnect according to utility pre-configured rules
- detect duplicate service disconnect/ reconnect events and ignore the duplicate events (e.g. Meter is already on -- reconnect event accepted with no action taken)
- cancel or update/reschedule scheduled disconnect/ reconnect events prior to their completion
- send a meter read and acknowledgement to Data Center Aggregator upon a successfully completed or failed electric service disconnect/ reconnect event
- enable an SCE Employee working on-site at the customer premise to be able to physically operate its service disconnect/ reconnect switch at any time. 24 hours, 7 days a week, 365 days a year
- support an external authorization/ authentication routine (i.e. by remote systems or field tool) to enable only active and eligible SCE employees to operate its service disconnect/reconnect switch on-site at the customer premise
- allow authorized SCE employee (while on-site at the customer premise) to operate the service disconnect/reconnect switch immediately (regardless of interval) or to schedule a connect/ disconnect for a future interval
- log date/time and status of attempts to operate the service disconnect/reconnect switch remotely or on-site at the customer premise. Log entries will include requesting user or system identity and authorization status
- remotely disconnected/reconnected on demand and have acknowledgement received by requesting system within 1 minute of request being initiated
- allow a reconnect event to occur following a disconnect event only after a configurable amount of time (e.g. at least 1 to 2 minutes) has elapsed since the disconnect event.
- Note: Should a disconnect event and reconnect event be scheduled to occur for the same meter on the same day, Meter shall log the events and automatically provide an on-demand read to the Data Center Aggregator without operating the disconnect/reconnect switch

AMI Preliminary System Requirements, SCE. June 2006.

Software-based Applications and Tools

To be effective, AMI tamper indicators need to be filtered to spot trends, outliers, and provide for reliable comparisons. Blink counts and outage flags need to be compared against neighbors. Normal meter and trouble work need to be backed out of meter tilts, removals, and power outages. Custom algorithms and a formal process are required to look at trends. Energy consumption needs to be compared—by individuals and by groups.

To be most effective, AMI data needs to be combined with the following:

- Class of customer
- Geographical information
- Normalization for weather, occupancy, and other similar factors
- Customer's past history—family, friends, and other businesses
- Other utility usage—gas, water, cable
- Experience

Software-based applications and tools must be used to analyze the data that are delivered by AMI metering and communications technology to utilities—revenue assurance departments in particular. There are three major categories of software-based applications and tools that are necessary for AMI to effectively detect and reduce non-technical losses and maximize its impact on revenue:

1. Meter data management systems
2. Statistical analysis
3. GIS—at time of installation and for identifying locations for abnormal behavior

Meter Data Management Systems

Advanced metering delivers frequent interval data, which greatly increases the amount of information a utility will have about consumption. The volume, frequency, resolution, and type of data (for example, interval demand data, voltage, outage events, and meter tempering indications) delivered by AMI from meters are vastly different from manual meter reads and mobile (drive-by) meter-reading systems.

MDMS is used to manage the large volumes of meter data generated from AMI systems. MDMS is the software that accepts data collected from an AMR/AMI system, stores the data, and forwards the data to utility systems such as billing. MDMS is an essential tool for utilities that may have tens or even hundreds of thousands or millions of meters generating data that are gathered in multiple ways.

Data Collection and Analysis

While AMI monitors customer power consumption , MDMS uses the data collected for statistical analyses that generate standard reports, such as Hi/Lo reads with statistical process control charts, multi-day bad meter reads, zero usage day with non-zero average, and custom meter groups. These can be used to identify customer load changes that may be related to meter theft.

MDMS is used to develop actionable intelligence for use in revenue protection programs. MDMS receives revenue protection flags from the meters and compares them with usage trends, outage information, and service order/field work to determine which are actual revenue protection issues and which are false positives.

By relying on a central repository of historic meter data, analytics can pinpoint usage patterns that might indicate meter defect, meter tampering, or theft of service. If a customer's energy usage remains abnormally low during heat waves, cold snaps, or before and after outages, then the meter might be malfunctioning. If more energy is flowing past distribution points than is being billed for, then it's possible that someone is stealing service. Without meter data management, this type of revenue-assuring analysis is nearly impossible.

MDMS is used to validate data against theft indicators, automatically initiating appropriate alerts and tracking responses. MDMS is used to set threshold levels for usage on a premise-by-premise basis.

Integration with CIS and Billing Systems

MDMS automates and streamlines the identification of accounts with potential theft, thus reducing the time and expense of unnecessary site visits by revenue investigators. With visibility into the probable condition of each meter in the system, revenue investigators can monitor accounts systemwide without additional investments in time, resources, meter seals, locks, and other security gadgets.

For optimum performance of AMI-supported applications such as tamper or leak detection and processing of on-demand and off-cycle reads, MDMS should be integrated with utility functions carried out in CIS, billing, and other systems such as load control. Customer service personnel, for example, should have access to daily and interval read information provided by AMI to respond to billing inquiries, process service cancellations, and perform other functions. This will require development of new screens for integrating and displaying data and can be time-consuming to develop and test.

Interestingly, MDMS identifies meter failure before the billing cycle, thus avoiding billing errors on both the hardware and software components of AMI, both contributors to non-technical losses.

Integration into AMI and Enterprise

To realize the benefits of revenue protection, including meter tempering and illegitimate consumption, AMI must be capable of providing the data required to detect theft. This means that MDMS should be able to ingest and analyze the AMI data to initiate, track, and close-out follow-up work orders via the utility's work order management system with respect to meter installations, change-outs, communications interfaces, maintenance, and upgrades.

MDMS is an integral and essential part of AMI with respect to developing solutions for non-technical losses.

MDMS and the AMI Technology Evaluations

Conceptually, the meter module hardware, communications infrastructure, AMI head-end system, the MDMS, and the integrations with a utility's existing hack-office systems should be thought of as one end-to-end integrated and seamless solution that, only together, can enable the utility to achieve the expected benefits of AMI. Hence, it is beneficial for a utility to assess the capabilities it requires of an MDMS and determine how the AMI data will touch the utility's existing systems, the same time when evaluating AMI technologies and developing an AMI business case.

Meter Data Management System, Tram, Hahn and Ash, Chris, Enspiria Solutions. August 29, 2005.

Statistical Analysis

AMI generates a wealth of data. The shear volume of this data demands that software applications be developed to perform statistical analysis for it to be useful for detecting and correcting non-technical losses. As meters become more sophisticated (solid-state meters flag many meter-tampering techniques automatically in real time), so do thieves. Software applications can be used to strike the balance in favor of revenue assurance.

Some of the more prevalent software applications and techniques for statistical analysis are described in the sections below.

Customer Profiling

Load profiles and data mining techniques can be used to minimize non-technical loss activities. Load-profiling methods and data-mining techniques can be used to classify, detect, and predict non-technical losses in the distribution sector due to faulty metering and billing errors. They provide a framework for the analysis of customer behavior.

Load Profiling

The key to this approach is the recognition of significant deviations known as outliers in the customer behavior patterns. The method of doing so involves modules including the load profiling and non-technical losses analysis in processing large volumes of data relating to customers' electricity consumption patterns. The load profiling module includes clustering customer behavior according to the loading conditions identified and allocating the clustered load profiles to the respective categories based on the customer and commercial indices. The non-technical loss analysis module uses the representative load profiles as a time series model and detects the outliers based on the set up benchmark based on abnormal and normal behavior patterns. The detected abnormalities due to non-technical loss activities are used as a reference to develop a forecast model on non-technical loss profiles with other external features.

Framework Analysis of Customer Behaviour due to Non-Technical Losses in Malaysian Electricity Supply Industry, Anisah Hanim Nizar, ITEE. July 17, 2006.

Interval Metering

Since AMI systems can support frequent readings and high data resolution, interval metering is possible. This allows the utility to study consumption patterns for anomalies that may indicate metering problems.[76]

Some "smart meters" measure consumption in intervals of an hour or less. The resulting increase in data points (from 4 or 12 per year to 8700+) allows utilities to develop highly sophisticated customer profiles. This information can be used to analyze consumption patterns at sites where theft is suspected.

Utilities can develop and compare profiles within the billing system. However, the process would likely slow down bill production. A far more efficient solution lies in the use of an out-of-the-box business intelligence application that extracts data from a billing or meter data management application, then builds and compares profiles in a non-production environment.[77]

A list of significant deviations based on interval data provides targets for investigation. Deviation from a profile norm is a good indicator of theft, sufficient to merit investigation.

Distribution Analysis

Metering cannot detect bypass-tapping supply before it reaches the meter. For most utilities, bypass is the primary theft method. Bypass on underground lines can go undetected for years.[78]

Using data from smart meters, distribution management systems can be used to reach a solution to this problem. A distribution management system can correlate energy meter readings with available feeder load data to identify feeder loss characteristics and a profile. Utilities can use these to create a ranking of the worst performing distribution feeders. This system perspective of feeder loss allows a utility to address load theft where it is greatest. Also, smart-meter-provided power quality data (for example, voltage, current, and power factor) can assist in determining the feeder section losses.

This analysis helps narrow the source of a loss to a relatively small number of sites. Looking at the accounts associated with those sites, along with information on ownership and purported use, points to the likely location of the theft.

Trends and Comparisons

Custom algorithms and a formal process are required to identify trends. Energy consumption needs to be compared by individual customers and by class of customers. Comparisons are made by combining AMI data with the following:

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[76] Load profile analysis using monthly meter readings is impractical for detecting energy theft. *Algorithm for Detecting Energy Diversion,* EPRI. 1991.

[77] New metering & grid applications improve theft detection, Adrian Patrick, PhD, Automatic Meter Reading Systems, Oracle, Utilities Global Business Unit. July 31, 2007.

[78] When the power is used for illegal, high-consumption "growing" and drug-manufacturing purposes, losses can be substantial.

- class of customer
- geographical information
- other utilities—cable, gas, water
- customer history and behavior patterns

Statistical Algorithms

MDMS uses a series of statistical algorithms that, in essence, perform the same initial screening and analysis work usually performed by a team of utility revenue assurance experts, only in a more consistent manner and at a much lower cost.

MDMS identifies revenue leakage by applying these algorithms, along with revenue assurance investigation best practices, across multiple utility internal data sources (CIS, MIS, WFMS) and appended with external data sources (SIC, zip +4, credit score, weather) to create a list of suspect accounts. The suspect list is a prioritized list of premises or accounts with reason codes and a weighted revenue recovery valuation of each opportunity. A suspect list is provided to the utility's revenue protection investigation team on a periodic basis for field investigation and subsequent actions (for example, customer contact, back-billing, mediation, and negotiations).

Geographical Information Systems (GIS)

GIS mapping and integration with customer databases is used to identify and locate consumers on the geographical maps being fed from the distribution network. There may be cases where an electric connection exists, but is not in the utility's record. There may be instances of unauthorized connections or unrecorded connections. On the other hand, there may be instances where a connection is recorded, but does not exist physically at the site.

GIS provides utilities with accurate data and useful information to manage their assets and customer base. GIS coupled with GPS can assist in maintaining data integrity and recovering "lost revenue."

GIS should be used to provide aerial photographs or maps of the area, with spatial references to the physical and electrical distribution network, metering points within buildings, and buildings without meters installed. All network and customer documentation should be linked, and all assets in the area should be mapped. Widespread access to relevant data should be available through a web-enabled client-server.

Installation of AMI at the substation level helps to target areas where technical and, more importantly, non-technical losses are problematic.

Results from analysis using GIS-enabled tools can be used to focus energy audits by revenue protection teams. In the case of major retail and industrial customers, technical specialists can prioritize locations for on-site audits, checking meters and installations, instrument transformers, metering and billing constants and ensuring that no by-passing is taking place.

GIS is an ideal integration platform for meter data, supervisory control and data acquisition (SCADA), and customer information systems, as shown in Figure 3-2.

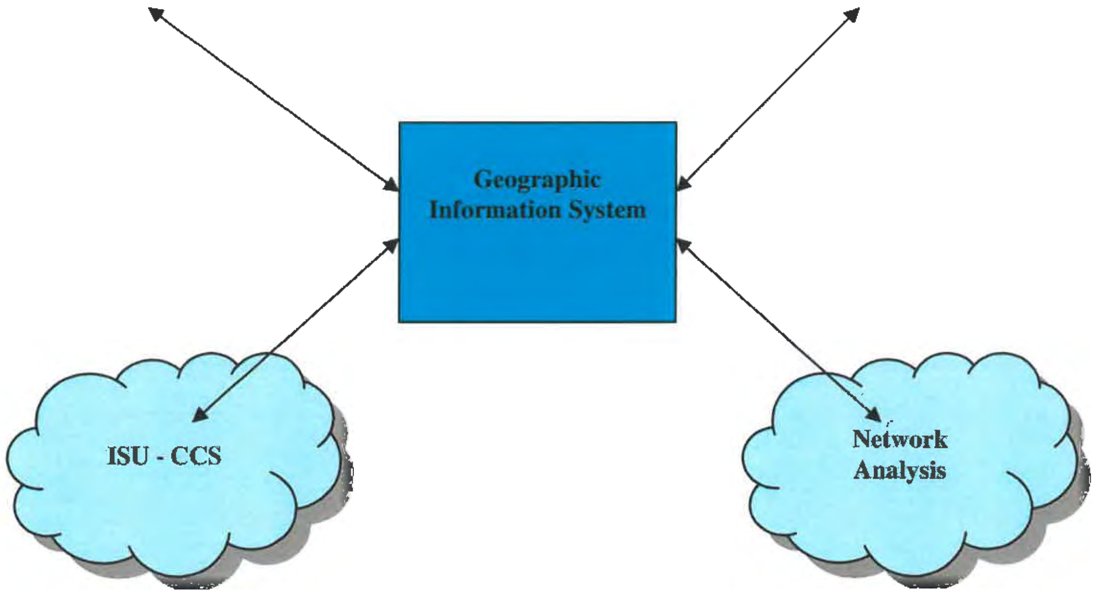

Figure 3-2
Geographic Information System

Tasks for which spatial data can improve processes are meter reading (including rollout of AMI systems), credit and collections, customer analytics, billing, and customer communications. An enterprise GIS fully integrated within the mainstream of utility IT infrastructures helps utilities understand customer behavior and their transactions.[79]

GIS can help visualize significant mismatches between known usage and actual consumption using GIS advanced network modeling.

Many utilities consider the GIS system as the "ultimate" source database, acting as a common repository for all enterprise applications. This is accomplished by integrating GIS technology into the mainstream business operations of the company.

[79] *GIS Enhances Electric Utility Customer Care*, An ESRI ® White Paper. May 2007.

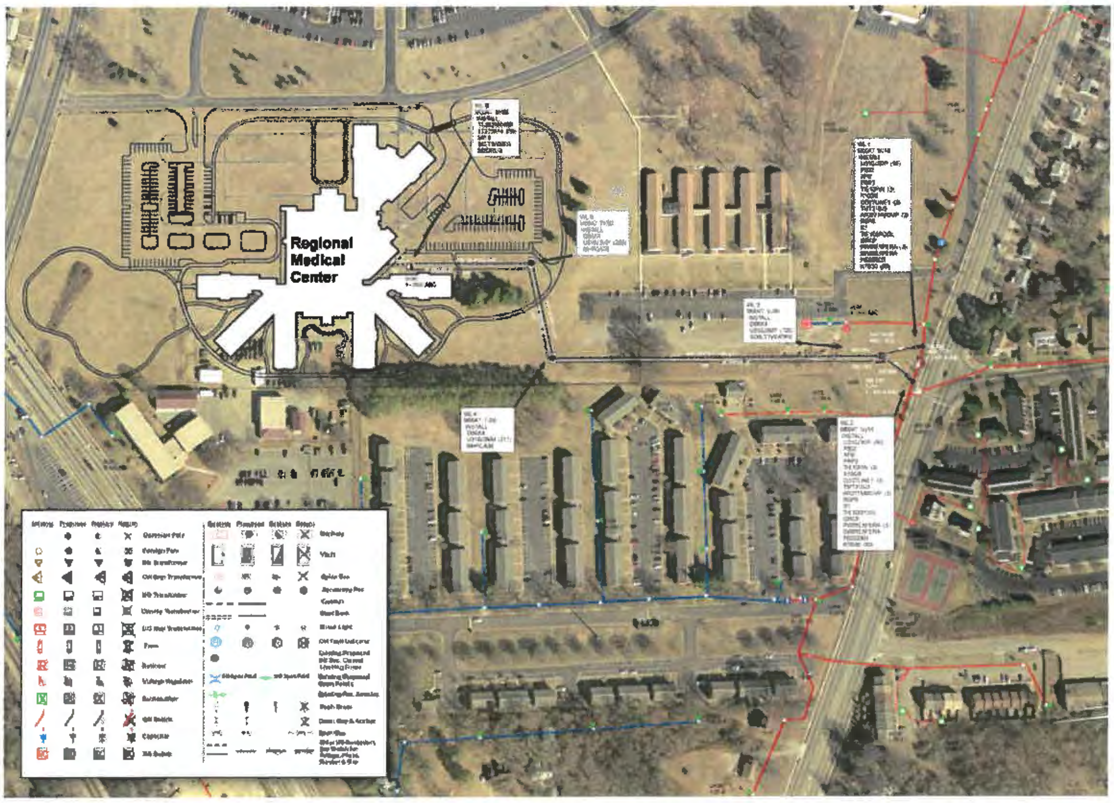

Figure 3-3
GIS Aerial Map

GIS Integration Functional Requirements

The functional requirements for integrating AMI with GIS are as follows: [80]

- Complete automation of the distribution network is not possible. It would require implementation of SCADA/DMS at every section of distribution system, which is prohibitively expensive. Hence, getting real-time data from SCADA/DMS for all parts of distribution network is not possible. This problem can be overcome by the integration of GIS with AMR/AMI.
- Normally, the metering data from AMR/AMI are available to billing personal. However, these data are not available to other employees directly. Once integrated with GIS, every employee can have access to data through multiple GIS applications.
- AMR/AMI data are helpful for detecting losses in the distribution system. Using GIS, losses can be viewed geographically and analyzed. This analysis can be used to map areas where there is a high incidence of theft or other distribution system losses. These maps can be used to develop predictive models (Figure 3-3).
- Energy consumption information can be used to build databases of real-time and historical (periodical) demand and energy data at the source (for example, feeders and

[80] A detailed discussion of this subject can be found in *GIS integration with SCADA, DMS & AMR in Electrical Utility*, Uday D. Kale and Rajesh Lad. Reliance Energy Ltd., Map India. 2006.

DTs) and load (consumers) levels. This information can be used to build network simulations of loading conditions and for load forecasting. These databases can be helpful in developing profiles, behavior models and incidence indicators for theft.

- With the data received from AMR/AMI, GIS tools can be used for energy auditing in a geographic context, which is useful in specifically identifying particular areas suffering high energy losses.
- The correct assessment of technical and non-technical loss components needs correct metering data. This information can be provided over the GIS platform. GIS tools can be used by network analysts to identify and display spatially feeders, transformers, and distribution areas having high-energy losses (Figure 3-4).

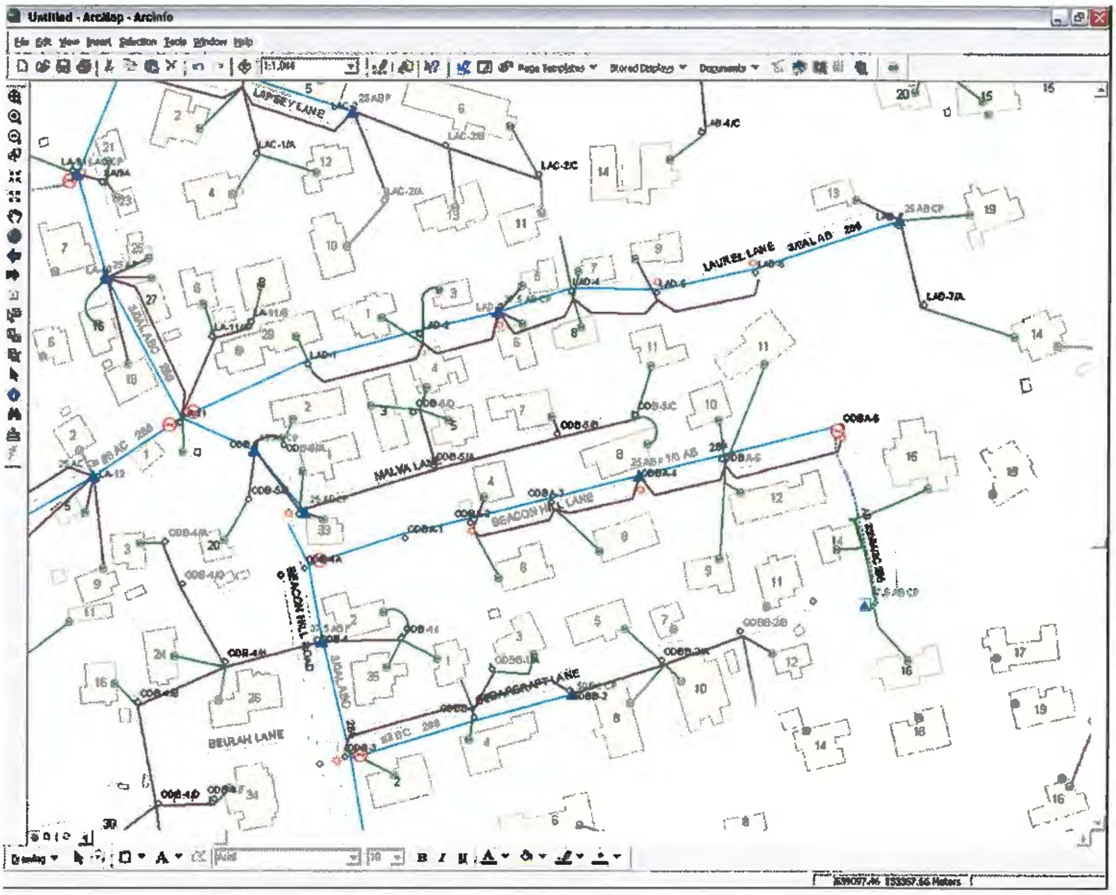

Figure 3-4
GIS High-Energy Loss Map

GIS and Field Inspections

GIS mapping of AMR/AMI data has been used successfully to identify locations for field inspections. These have led to high "hit rates" for the detection of meter tampering. An example of GIS for field inspections is shown in Figure 3-5.[81]

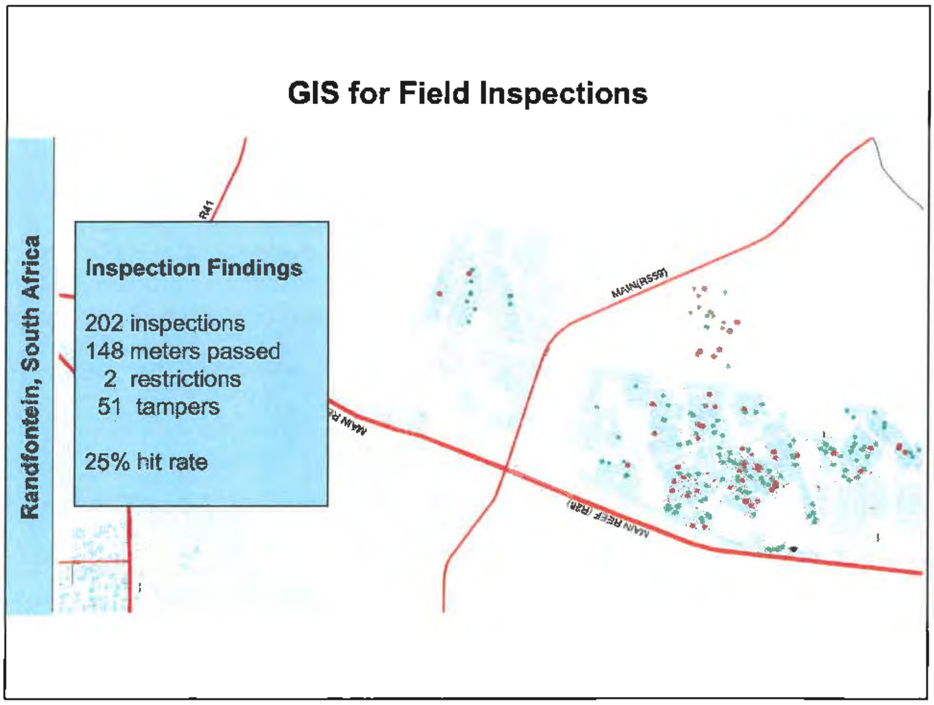

Figure 3-5
GIS for Field Inspections

Analyzing Theft at Substation Level

With integrated GIS, it is possible to access exactly the geographical areas where theft is most prevalent, areas where theft can be preempted by enhanced levels of vigilance, and areas where revenue assurance should step up its efforts and be more accountable for results. Typically, the area served by a substation is only a few square kilometers in size, facilitating the implementation of corrective measures.

GIS can play a major role in identifying areas of the distribution network where theft is likely. Identifying potential theft in the distribution network is accomplished by the integration of billing and SCADA systems on a GIS platform.[82]

[81] *Resource & Revenue Protection as a Tool for DSM*, Christophe Viarnaud, Actaris and Gregor Schmitz, BreakThru Consulting.

[82] *Role of GIS in Preventing Power Pilferage,* Dr. Nagesh Rajopadhyay, Manish Arora and P. Madhusudhan, Info Tech Enterprise Limited, Hyderabad. GIS Based Distribution System Planning, Analysis and Asset Management Training Program, USAID.

SCADA systems continuously collect real-time readings of all electrical parameters at monitored points on feeders.[83] The system obtains information on the status of various switching devices (for example, circuit breakers, switches and isolators) and transformer parameters (for example, tap position).

When electronic meters are installed at the customer level, they can be equipped with an interface for communications with the SCADA system, using an industry standard protocol. Meter readings can then be used both to monitor the load and to detect attempts to tamper with the meter. As soon as a tamper is detected, the meter/consumer can be tagged on the GIS system. The information can then be passed on to revenue assurance for physical checks and corrective action.

PSS/Engines™ must be interfaced with GIS for network analysis and optimization. A data model must be created in GIS for geographic locations as well as for the network.

Steps for the system and database integration and GIS mapping:

- Interface of billing system to GIS (GIS application software reads external relational database management system [RDBMS] of billing system).
- Entry of billing-related information to customer database.
- Identify the total power delivered from the substation (P-total) and the total power billed to the customer (P-billed).
- Calculate network power loss (P-lost) with network analysis tools and map network data in GIS.
- Calculate power theft (P-theft) or commercial loss at the substation level. Formula: (P-theft) = (P-total) - (P-billed) - (P-lost).
- Plot the results on GIS.

A similar analysis can be made at the transformer level, provided that the meter is installed at the transformer and a reading is available.

A link must be maintained between the external billing database and the GIS database. Billing data must be populated simultaneously in the external database and the GIS database. After the entry of meter data at a substation level, the system can be asked to evaluate the total commercial loss.

[83] These parameters include voltage, angle, power factor, active power, reactive power, and energy.

Implementation of AMI Technology

The way in which an AMI installation is planned and executed has a major impact on its success in ensuring that the technologies are installed properly, detecting meter tampering and by-pass at the time of installation and setting up and integrating the data management systems and GIS platform for revenue assurance programs in the future. It must be recognized that installation of hardware and software is as important as the technologies themselves for realizing the benefits that AMI offers for the detection and control of non-technical losses.

Successful implementation of AMI technology requires the participation of experienced revenue assurance staff at all stages of the process—planning, procurement, installation, and integration into the utility enterprise systems. These individuals have valuable insights into the transition from manual to remote meter reading and auditing. They have much on-site experience to share for meter replacement. Moreover, they understand the need for comprehensive data management tools. Most importantly, revenue assurance offers quality control for the realization of the operational savings that provide the economic justification for many AMI programs.

4
CHAPTER 4

Overview PPL Electric Utilities

PPL Electric Utilities is the regulated electricity and gas subsidiary of PPL Corporation. The annual revenues and assets of PPL Corporation are $6.9 billion and $19.7 billion, respectively. PPL Electric Utilities serves over 1.4 million customers over 10,000 square miles in Central Eastern Pennsylvania (Figure 4-1).

PPL Electric Utilities has a peak load of ~7,700 MW with 36.7 billion kWh delivery.

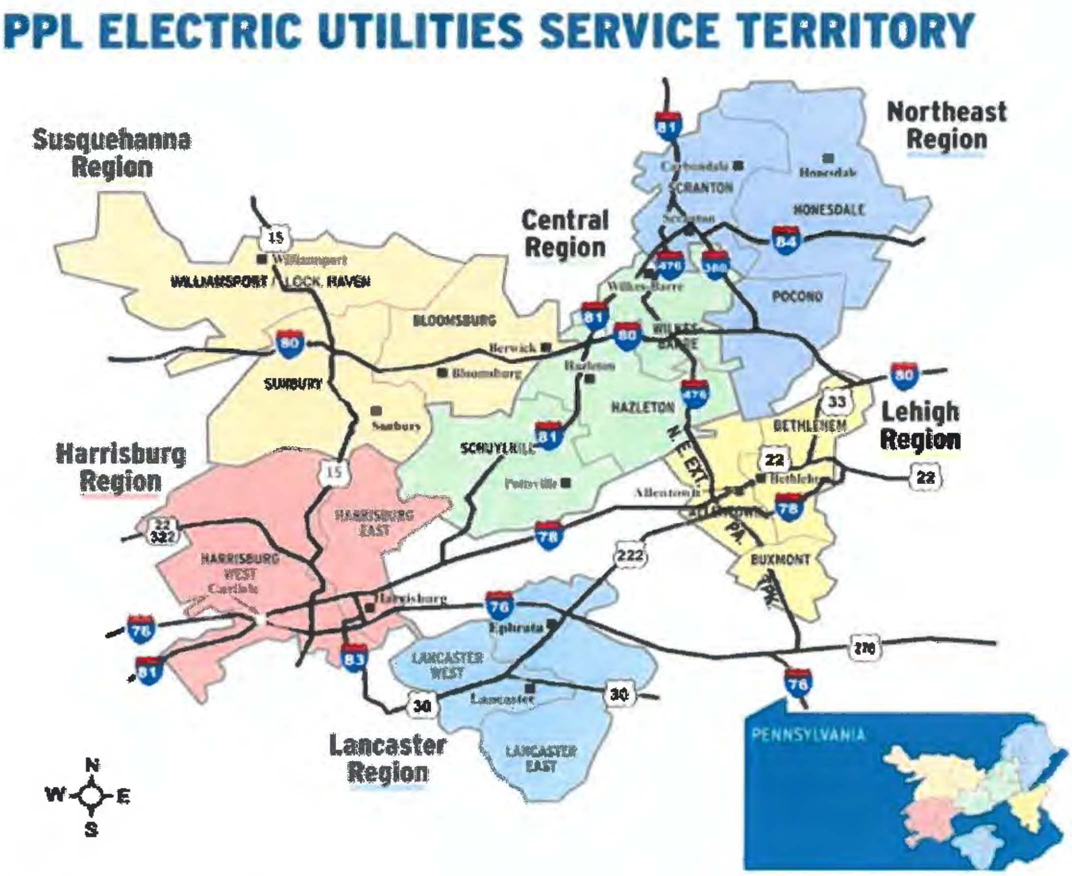

Figure 4-1
PPL Electric Utilities Service Territory

PPL Electric Utilities was one of the first utilities to introduce an automated meter-reading system, starting the program in November 1999 and completing the deployment to its 1.4 million customers in October 2004. Beginning in the spring of 2002 and concluding in the fall of 2004, PPL deployed an automated meter-reading system that included the replacement of over 1.4 million meters, installation of communications equipment in over 330 substations, and modified meter data and billing systems. Total implementation cost was $163 million. The automated meter-reading system replaced 175 manual meter readers and allowed the reduction of personnel for large power installations from 17 to 11.

With manual reads, PPL Electric Utilities experienced 95% accuracy (due to human error and weather, especially snow); accuracy with automated meter reading is now close to 99.8%.

PPL Electric Utilities started change management for business processes six months before installation. Before installation started, 200 business processes were reviewed; 70 risks were identified and addressed and appropriate changes made to ensure the successful transition to the automated meter-reading system. Many of these changes related to billing processes and impacted revenue assurance and, thus, non-technical losses.

The information technology staff was actively involved in the project team, contributing to the smooth transition. During the installation period, manual meter reads were sent to billing using middleware, so downstream processes did not notice the difference between manual and remote meter reads. The computer software programs and interfaces necessary to transfer the automated meter reads to the PPL billing system were developed in-house. Among these were the data validation and revenue assurance tools. Statistical analysis was used very early on. From the beginning of the project, the information technology staff, using its own software, provided effective and productive applications for revenue assurance.

Although the system deployed by PPL Electric Utilities was an automated meter-reading (AMR) system, it was designed as an advanced metering infrastructure (AMI) system upon which expanded capabilities could be deployed. These expanded capabilities include two-way communications and the use of a commercial MDM solution.

The AMI system reads meters three times per day; hourly data collected daily for each customer. The database currently (2008) holds over three terabytes (two years of data). This is the largest database of hourly data in the industry.

PPL Electric Utilities was one of the earliest utilities to deploy and utilize AMR/AMI throughout its entire service territory, establishing it as one of the leaders in the industry. As of 2006 it had the second largest deployment in the United States (1,353,024 meters), after PECO Energy (1,759,913); Wisconsin Energy was third (723,000), Wisconsin Public Service fourth (396,837), and United Illuminating fifth (324,992).

The transition from manual to remote meter reading at PPL Electric Utilities was well managed with an inclusive and highly competent project team, making it a model for the industry. Most importantly, with respect to the subject of this study, the AMR/AMI system at PPL Electric utilities provides new and innovative tools for revenue assurance that have a positive impact on the reduction on non-technical losses.

Revenue Assurance Using Meter Data from AMI with Meter Data Management Software

AMI fundamentally alters the way revenue assurance operations are performed. In the past, the Revenue Assurance group at PPL Electric Utilities used various strategies to identify specific target accounts for investigation. Most of these strategies involved manual analysis of large quantities of data, a labor-intensive exercise. The data available for such queries were generally limited to daily and monthly consumption. The results were based on an *ad hoc* process that takes considerable time, with different screening tests being designed and deployed at different times. AMI, with a robust MDM system, changes this paradigm in several ways.

The collection of higher-frequency data and meter status by AMI—reverse rotation flags, outage count indicators, interval data, and metered usage on previously cut meters—is just the beginning of the assurance solution. MDM software helps utilities analyze AMI data, providing knowledge about customer energy use. In-depth analysis helps pinpoint where and by whom power is being diverted, making it easier to identify cases of theft. For example, such analysis enables the utility to discover when there is energy use on non-paying accounts and when there is no use for specific time periods on an active account.

Data Repository

The core repository of data is collected from multiple sources: AMI meters, weather, customer and billing, SCADA, GIS mapping and real-time pricing, as shown in Figure 4-2. The data are validated and stored in two scenarios, working and approved.

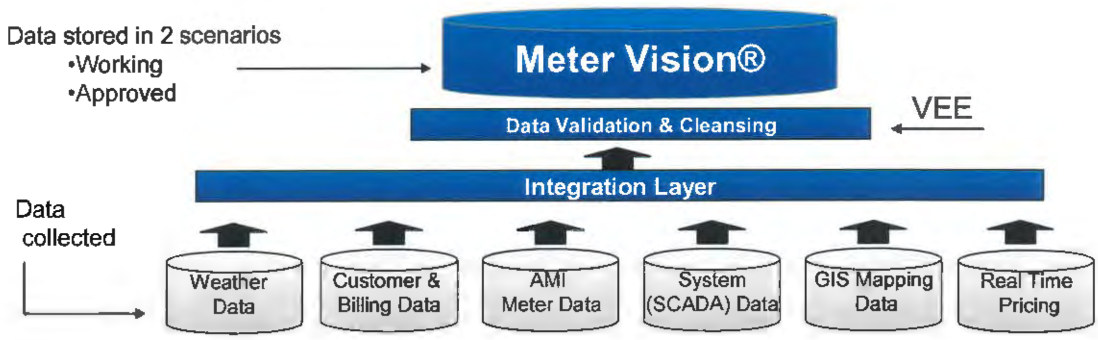

Figure 4-2
Data Repository

Data Repository and Applications

Revenue assurance software allows PPL Electric Utilities to zero in on problem accounts by combining data collected by the AMI system, such as daily readings, interval data, and momentary interruption notifications (blink counts) with other pertinent information such as daily temperatures, meter status, and account status.

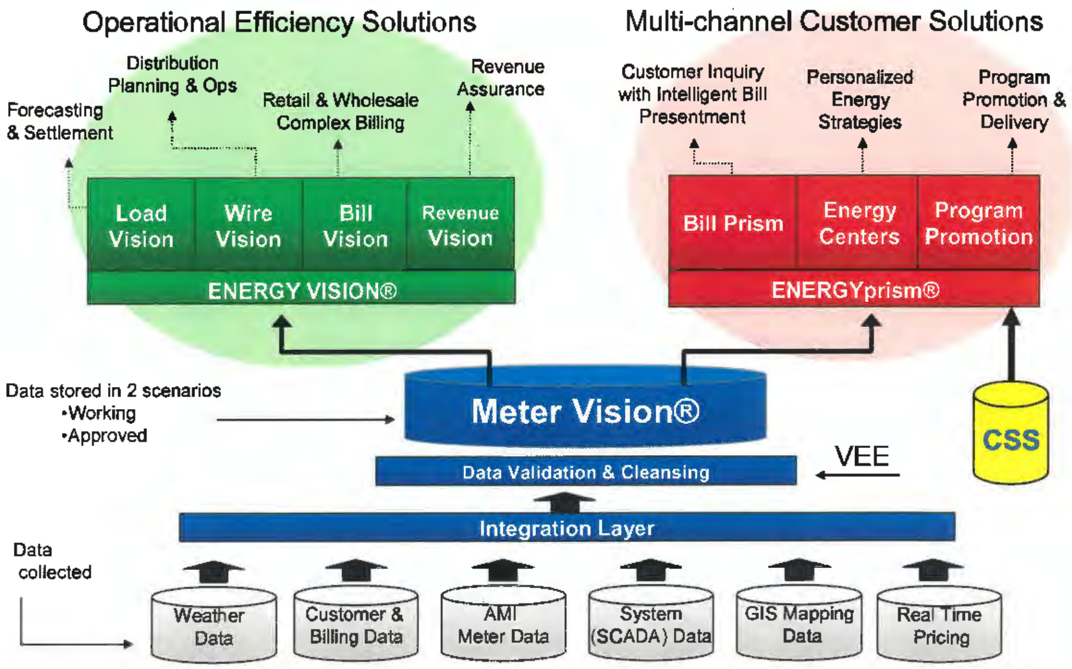

Figure 4-3
Data Repository and Applications

The combination of data and applications for analysis together constitute the Revenue Vision solution at PPL Electric Utilities (Figure 4-3).

Revenue Vision

The Revenue Assurance group at PPL Electric Utilities uses MDM software, called Revenue Vision, to help them simplify the process for identifying possible cases of theft, meter tampering, or equipment problems. This takes a significant amount of guesswork out of the effort to identify possible theft cases. Rather than make assumptions about the cause of a reduction in consumption, the granularity of data available from MDM can provide a pattern that can be used to identify theft or failing equipment with a high degree of confidence so that the site visit to confirm will be fruitful. It also allows users to create rules and logic, manage the list of outputs, tweak logic for better results, and group the results by geographic location to make it easier to assign work to field investigators. An optimum solution would automatically notify group members of anomalies around usage patterns.

PPL Electric Utilities uses a commercial MDM solution to improve analyses of large volumes of interval, daily, and meter data collected by its AMI system. By combining various meter, premise, and account data, the software makes it easier to identify problem meters. PPL Electric Utilities identifies suspicious consumption patterns by applying specific, utility-defined screening tests to a targeted population of accounts, meters, or other entities. The goal is to define tests narrowly enough so that the data combination yields a true and manageably sized "hot list" of accounts requiring investigation.

Revenue Assurance Application

- The revenue assurance application is used today to find meter issues as well as theft.
- The application collects raw data from meters with a specific scenario.
- For example, meters with 3 hours of no use are collected between the hours of 6 pm and 6 am and reports them to a "hot list" for further investigation.
- Additionally, it collects meters that have reverse rotation with blinks and puts them on a "hot list" for additional investigation.

Tests

The Revenue Assurance group began its project by evaluating existing tests already in use for assessing monthly meter readings. During the course of the review, they were able to determine the biggest revenue loss issues, such as equipment malfunctions, installation issues, and potential theft, and to identify usage patterns that were indicative of each problem, as well as the customer class or attribute that should be tested. Upon completion of this exercise, the group came up with eight logic tests to implement within the MDM application and then determined the criteria for each; for example, the meter type or the account type as well as selecting a schedule for running the test (weekly, monthly, or quarterly).

Design and implementation of screening tests within MDM are distinctly separate steps. Analyses are designed to fit customer load and data characteristics to effectively identify energy theft or tampering. Once an analysis is designed, it is implemented as a regular production process, making it possible to keep up with the examination of current data and alert the Revenue Assurance group of anomalies as soon as they arise.

The design step involves exploratory analysis of different test schemes by running, reviewing, and comparing different result sets. Hourly data are utilized for these tests and supplemented by external data sources such as weather data, GIS, and customer characteristic data. In the design phase, these tests are run on all or just a sample of customers, with the primary purpose of evaluating the effectiveness of the tests, rather than simply generating customer lists from the tests.

Tests

- Periodic zero use/with blink—shows meter blinks and zero usage
- Periodic zero use/no blink—same above with no blinks
- Reverse rotation/with blink—shows reverse meter rotation
- Reverse rotation/no blink—same as above with no blink

Note: Typically, abnormal blink counts and reverse rotations counts are due to meter tampering.

PPL continues to refine other tests that will allow them to monitor accounts within two days of an event (for example, termination for non-payment or slowing or stopped meter).

The implementation step is automated. Once logic tests are found to be effective by the analyst, they are put into production by scheduling them as automated runs for whatever period makes sense. All AMI data are initially screened by the validation rules inherent in the MDM system.

After validation, certain accounts are identified for further review. The revenue assurance analyses are run automatically on selected meters. Tests can be nested into a single logic string within a single production run, rather than performed sequentially in multiple runs.

Analysts apply standard tests or test combinations to specific accounts or groups of accounts. Failure of a combination of tests may detect meter tampering. For example, the combination of a loss of power indicator on a meter with a reverse rotation flag is a better indicator of theft than either test alone. No one test determines energy theft or meter tampering, but various combinations of failures may place an account or meter on the suspicious account list.

Workflows

The next step in implementing the logic tests required that a workflow be set up for each of the tests (Table 4-1). The workflows consist of a name, brief description, the group of entities to be included in the test, and the filters necessary to identify the attributes of the entities included. Once the workflows were completed, the group determined how often to run the test.

PPL Electric Utilities generally runs tests weekly, but has the flexibility to change the frequency of test runs. Weekly runs allow better management of output, and there is an added security benefit from a frequent "electronic eye" on every meter in the field.

Table 4-1
Revenue assurance workflows at PPL Electric Utilities

Revenue Assurance Workflows at PPL Electric Utilities	
Workflow	**Description**
800 Series Commercial	Captures commercial meters that have 20% or greater decrease in monthly consumption and/or peak demand in comparison with lowest monthly consumption and peak demand of previous 12 months
800 Series Residential	Captures residential meters that have 20% or greater decrease in monthly consumption in comparison with lowest monthly consumption of previous 12 months
Seasonal Use	Captures seasonal meters that have 20% or greater decrease in seasonal consumption and/or peak demand in comparison with seasonal consumption and peak demand 1 year and 2 years ago
Billing Constant	Captures meters for which billing constant changed from that of previous month
CIM Monthly Commercial	Captures commercial meters that have registered 1000 kWh of consumption since account became inactive
CIM Monthly Residential	Captures residential meters that have registered 1000 kWh of consumption since account became inactive
CIM Weekly Commercial	Captures commercial meters that register average daily consumption of 500 kWh or greater since account became inactive
Load Factor Commercial	Captures commercial meters that have monthly load factor of 1 or greater
Load Factor Residential	Captures residential meters that have monthly load factor of 1 or greater
Periodic Zero Use Commercial	Captures commercial meters that register four or more consecutive hours of true zero use during calendar month (excl. power outages)
Periodic Zero Use Residential	Captures residential meters that register more than 40 occurrences of consecutive 12 hours of zero use during calendar month (excl. power outages)
Reverse Rotation and Blink	Captures meters that register reverse rotation and blinks, indicating meters potentially tampered with
Reverse Rotation and No Blink	Captures meters that register reverse rotation but no blinks, indicating defective meters creeping backwards
Reverse Spike Commercial	Captures commercial meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Reverse Spike Residential	Captures residential meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Zero Use Commercial	Captures commercial meters that register zero consumption for calendar month
Zero Use Residential	Captures residential meters that register zero consumption for calendar month
Company Use	Captures meters classified as Company Use so they can be verified as such
Commercial Rate and Residential Revenue Class	Captures meters that have commercial rate class and residential revenue class
Residential Rate and Commercial Revenue Class	Captures meters that have residential rate class and commercial revenue class

Figure 4-4 shows a workflow that is used to find commercial meters that have 20% or greater decrease in the monthly consumption and or peak demand in comparison with the lowest monthly consumption and peak demand of the previous twelve months.

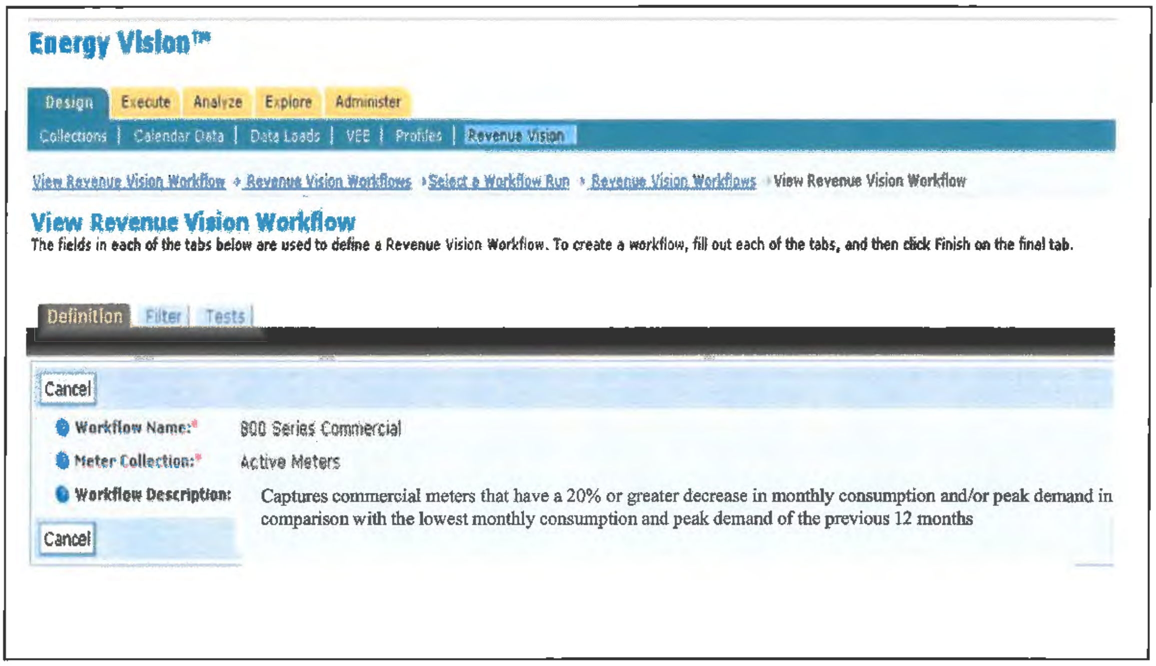

Figure 4-4
800 Series Commercial Workflow (Screen Print)

Filter

Within Revenue Vision (see Figure 4-5 Data Repository and Applications) a filter is applied by selecting the specific attributes, as well as a specific value such as commercial vs. residential—active vs. inactive—and so on.

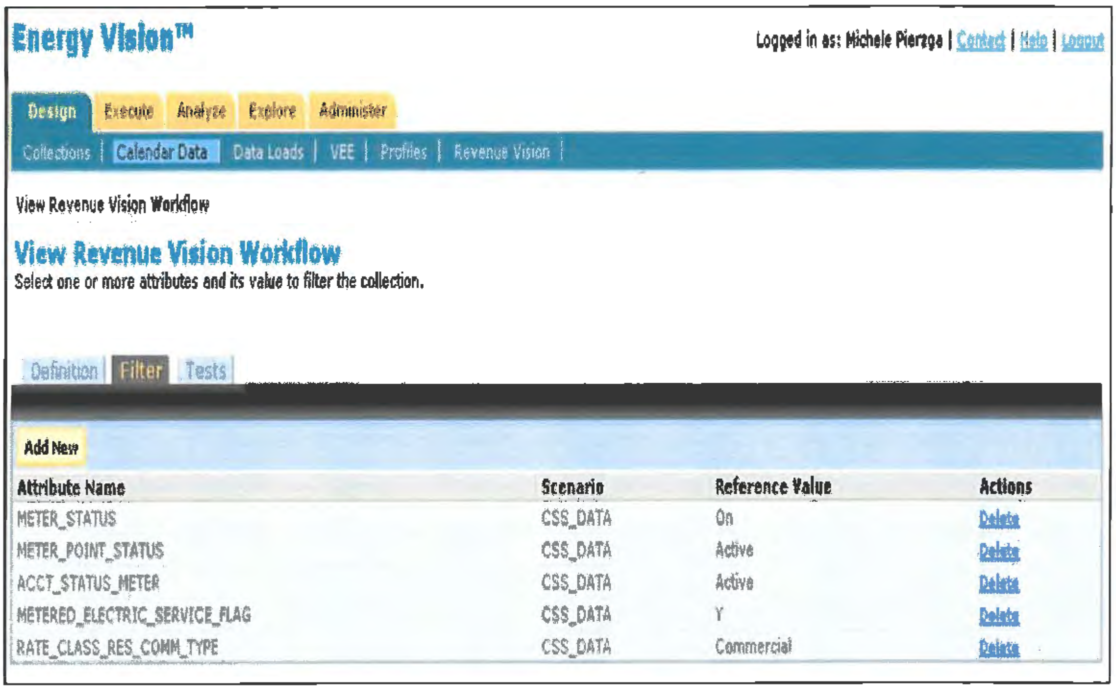

Figure 4-5
Filter (Screen Print)

"Hot List"

The results are displayed on a "hot list" (Figure 4-6) from which a Revenue Assurance specialist can pinpoint candidates for further investigation and corroboration of the AMI indicators.

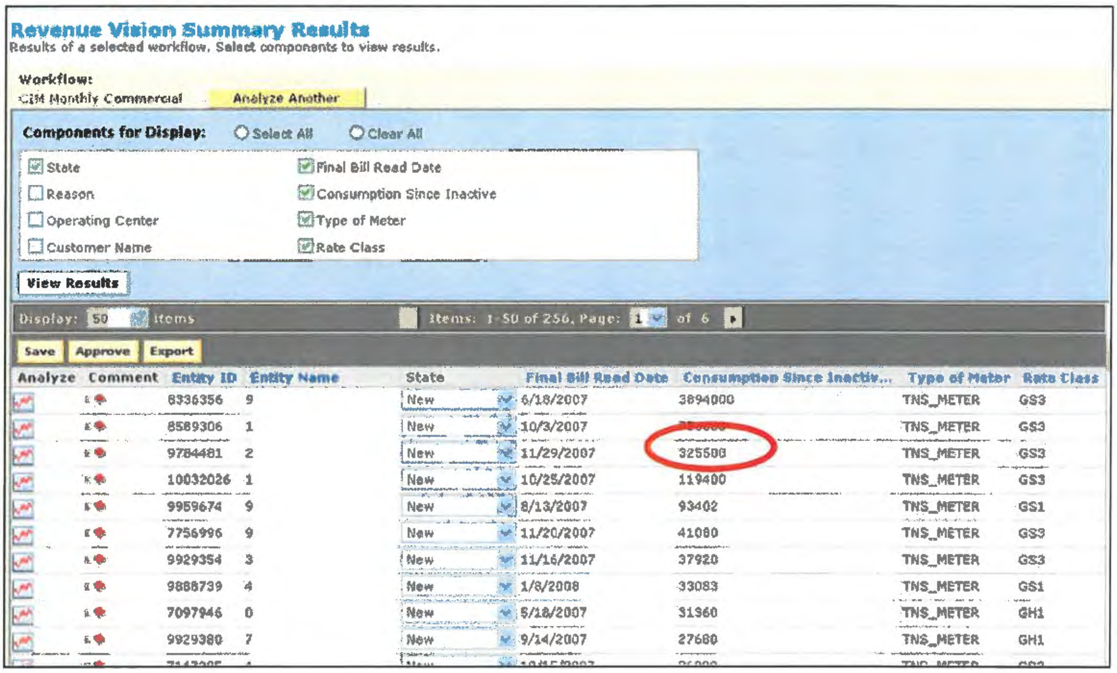

Figure 4-6
Hot list (Screen Print)

The "hot list" is used to prioritize revenue assurance leads for field personnel, thus reducing service order costs and efficiently identifying likely sources of non-technical losses.

Example of Theft Detection Using a Usage Pattern

In one recent case, PPL Electric Utilities was able to identify potential theft by looking at a usage pattern (Figure 4-7).

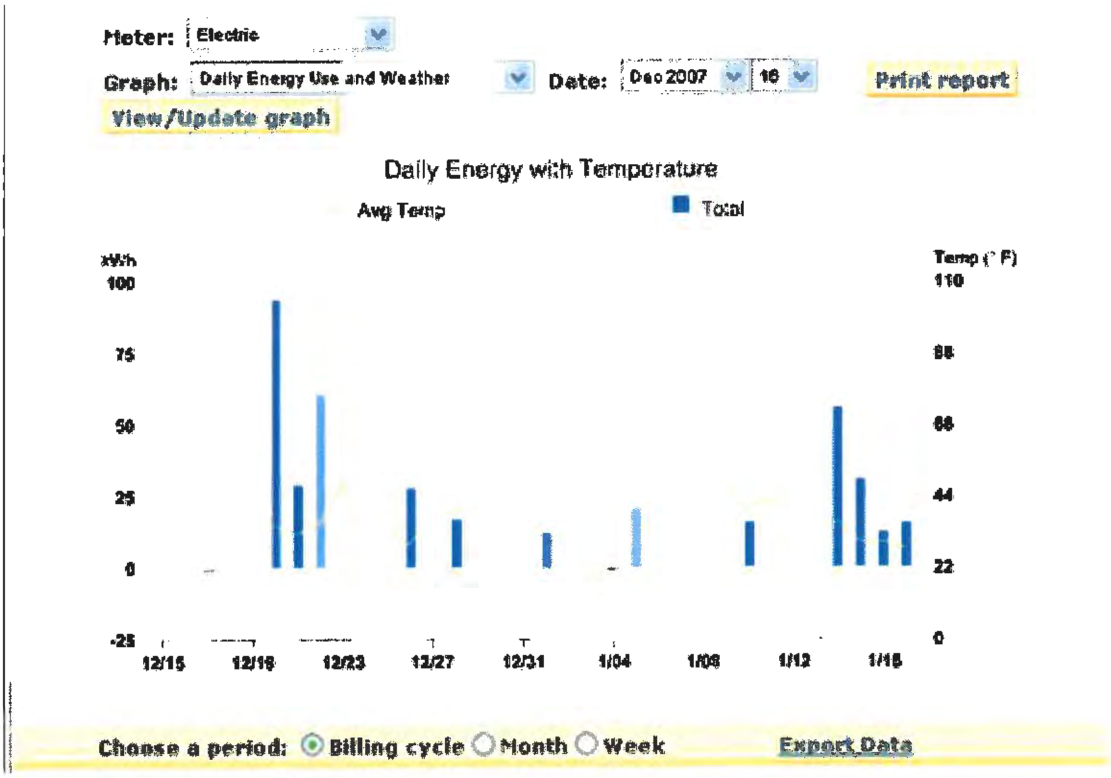

Figure 4-7
Usage pattern indicating abnormal meter behavior

The graph, taken from reports output from the MDM, indicates a suspicious usage pattern, with the meter going into a reverse rotation several times during a single billing cycle. What is more, there are days during the month when the customer is not using any power, while on other days the meter recorded usage. On December 20, 94 kW of usage was recorded, for example, while on January 3, when the temperature was -8°C, no usage was recorded. An investigation of the premises based on analysis of the AMI data indicated that the customer had tampered with the meter. Wires were attached to the meter's potential clip (Figure 4-8).

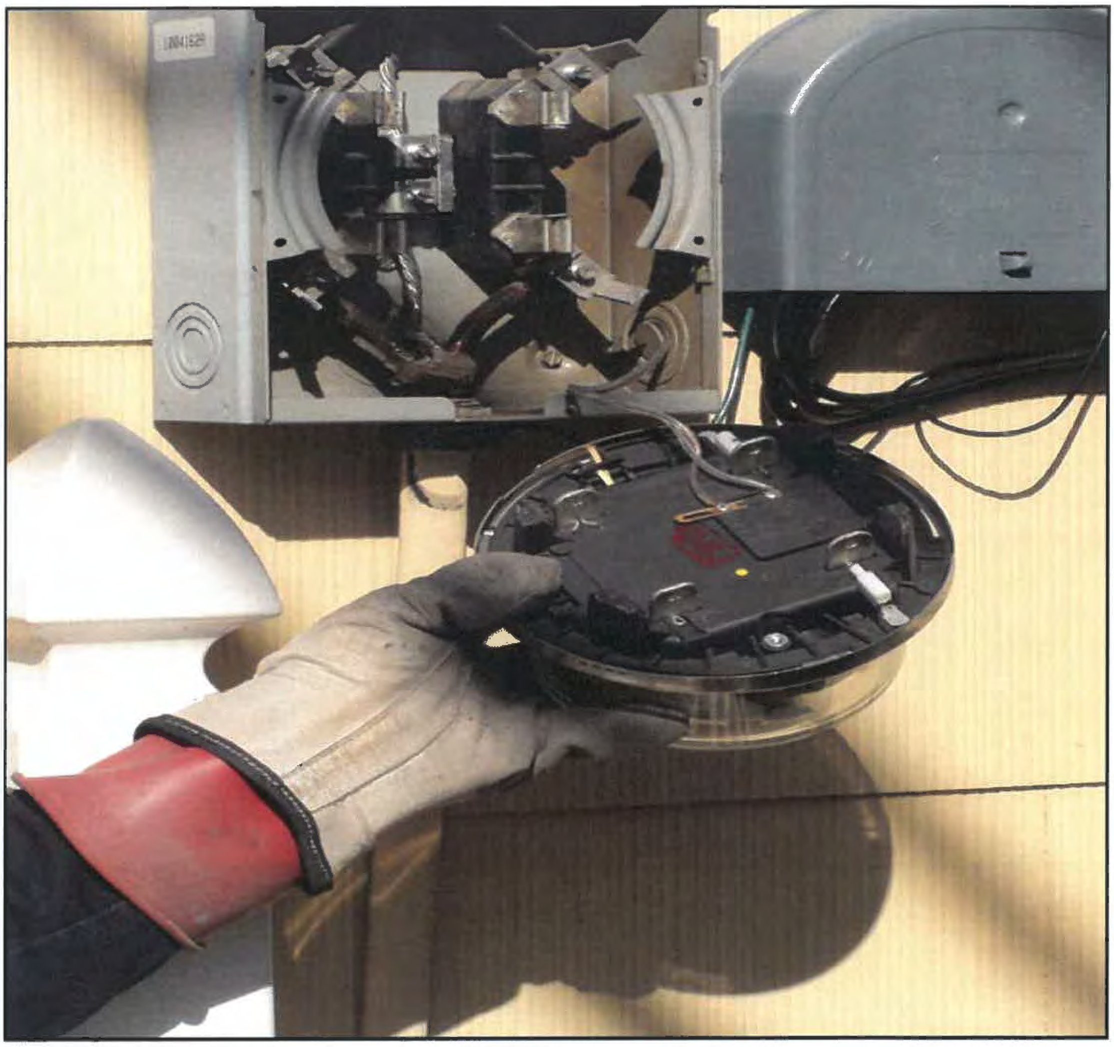

Figure 4-8
Meter recorded in Figure 7 with wires attached to its potential clip

The bypass was controlled by a simple toggle switch (Figure 4-9).

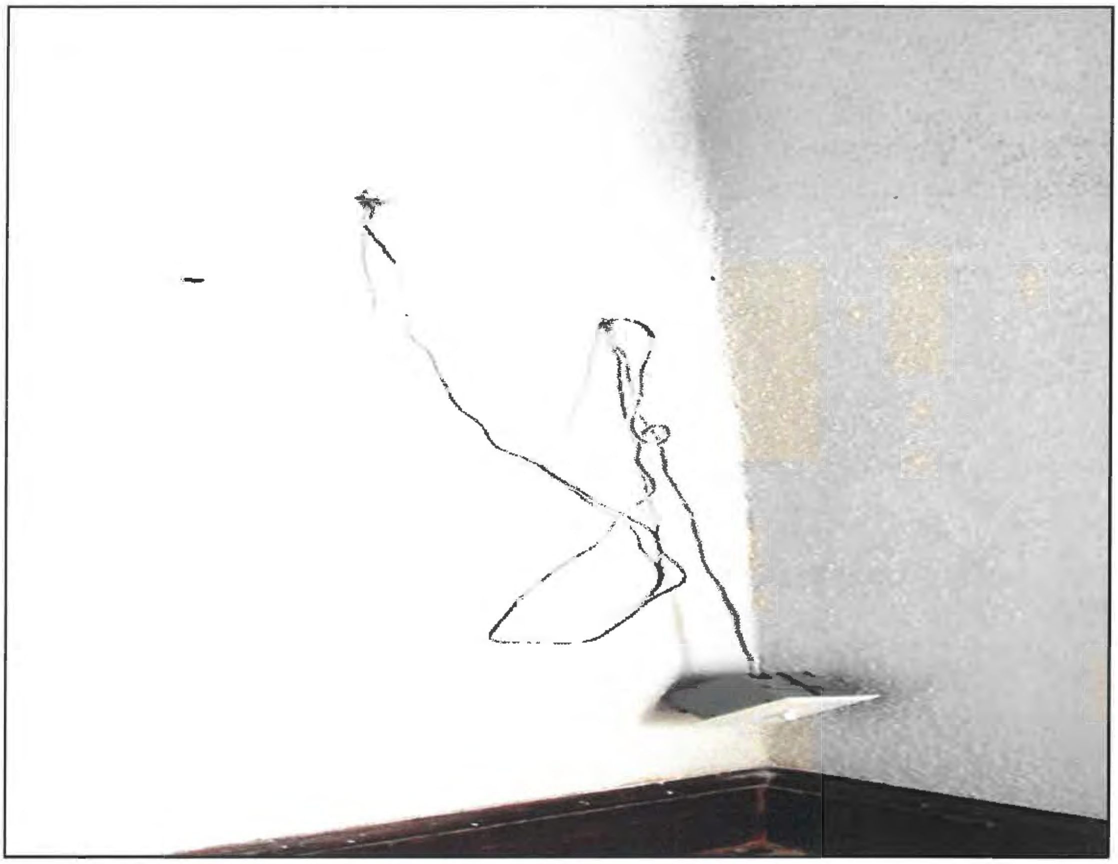

Figure 4-9
Toggle switch controlling the meter bypass

In this case, PPL Electric Utilities was able to use the interval data to extrapolate usage for rebilling purposes from the periods that were recorded.

Further, PPL Electric Utilities can use the detailed data for responding to questions raised by the judicial system.

Results

PPL Electric Utilities has had positive results from implementation of MDM-based revenue assurance software. The results for April and May 2008 are shown in the insert below.

RESULTS
April and May 2008

- Forty (40) cases were identified for a field investigation where 100% resulted in action being taken.
- Eighteen (18) of the cases were a result of equipment issues.
- In twenty (20) of the cases, theft was detected.
- Two of the cases revealed customer-owned generation via windmill and solar panel; these cases were identified through anomalies in blink counts and reverse rotation on the meters.

Reduction of Non-Technical Losses Using Meter Data Management

As defined in Chapter One, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These losses are associated with unidentified and uncollected revenue, arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of utilities, due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses. In this example, the focus has been primarily on issues related to theft. However, in the future, PPL Electric Utilities expects to further maximize the benefits that can be derived from its meter data, such as using the features of its MDM system in customer service to respond more quickly and accurately to high-bill inquiries.

AMI at PPL Electric Utilities is an evolving enterprise. The ongoing initiatives of the AMI operations team will lead to further reductions in non-technical losses, as well as further benefits in terms of operational efficiencies and customer service.

Sources

AMI and MDM Program—PPL Electric Utilities, Mike Godorov, Manager; AMI Operations, Kimberly Golden, Supervisor—Information Solutions; and Wayne Fairchild, Special Project Manager, AMI, interviews and presentation. September 18, 2008.

PPL Electric Utilities Reduces Revenue Losses with AMI, Bernie Molchany, Manager—Revenue Assurance, PPL Electric Utilities; Michele Pierzga, Lead Business Systems Analyst, PPL Services Corporation; and Jackie Lemmerhirt, Director of Product Management, MDM, Aclara, Metering International. Issue 3 2008.

Using Meter Data from AMI with Meter Data Management Software to Identify Theft and Equipment Issues, Michele A. Pierzga, Lead Business Systems Analyst, PPL Services Corporation, Autovation 2008, Atlanta, GA. September 7, 2008.

A
APPENDIX

Product Differentiators

- Each product has its own distinct functional strengths and weakness.
- Each product has its own unique architecture differentiators, such as the ability to perform and scale as needed.
- Each product is implemented with differing technologies that the utility IT department has to support and integrate with other applications in the enterprise.
- Some products have service-based architectures at the enterprise level; others do not.
- Some products have well-defined interfaces and points of interoperability; others do not.
- Some products meet industry and international standards; others do not.
- Some products adhere to Smart Grid principles;[84] others do not.
- In addition, each vendor is unique in its level of product development maturity and implementation experience and expertise.

Utilities are encouraged to find the solutions that best fit their needs—in the present and foreseeable future.

[84] As envisioned by Smart Grid researchers such as EPRI, the California Energy Commission's Public Interest Energy Research program, the Modern Grid Initiative, and DOE's GridWise program.

Vendor List

Aclara Software
- Energy Vision®
- http://www.aclaratech.com/software/

Advanced AMR Technologies, LLC
- 8800 Energy Information and Control System
- http://www.advancedamr.com/

American Innovations Ltd.
- AIMetering System®
- http://www.aimonitoring.com

BPL Global
- Power SG™ Theft Detection
- http://www.bplglobal.net/

Detectent, Inc.
- Revenue Enhancement Suite
- http://www.detectent.com/

E-Mon LLC
- E-Mon Energy™
- http://www.emon.com

Echelon Corporation
- Networked Energy Services
- http://www.echelon.com

Ecologic Analytics, LLC
- WACS Meter Data Management System
- http://www.ecologicanalytics.com/

EKA Systems, Inc
- Energy Insight
- http://www.ekasystems.com

Elster Electricity, LLC
- EnergyAxis® System
- http://www.elsterelectricity.com

eMeter Corporation
- eMeter's Consulting and Implementation Services
- http://www.emeter.com/

EnergyICT Inc.
- COMServerJ
- http://www.energyict.com

Enerwise Global Technologies, Inc
- Metering & Integration
- http://www.enerwise.com

Envision Utility Software Corporation
- foCIS™
- http://www.envworld.com

IBM Corporation
- Asset Monitoring and Advanced Metering
- http://www.ibm.com/us/

InStep Software, LLC
- Enterprise Energy Management Software
- http://www.instepsoftware.com

Itron
- Enterprise Edition Customer Care
- http://www.itron.com

MeterSmart
- Meter Data Management
- http://www.metersmart.com

Metretek Inc.
- DC2000
- http://www.metretekfl.com/

MU Net, Inc.
- WebGate® System
- http://www.munet.com

Neptune Technology Group Inc.
- FIELDNET®
- http://www.neptunetg.com

Oracle
- Oracle Utilities Meter Data Management
- http://www.oracle.com/industries/utilities

OZZ Corporation
- Meter Data Management Solutions
- http://www.ozzcorp.com

Powel, Inc.
- Meter Data Management
- http://www.powel.com/

Power Measurement
- EEM Systems
- http://www.pwrm.com/

SAP America, Inc.
- SAP Enterprise Data Management
- http://www.sap.com/usa/industries/utilities/index.epx

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Appendix A-9

AMS Opt-In Online Customer Survey

June 2017

Advanced Meter Early Adoption Program (AMS Opt In)

Online Panel: May Survey Results
June 2017

LG&E KU
PPL companies

Objective & Methodology

Objective

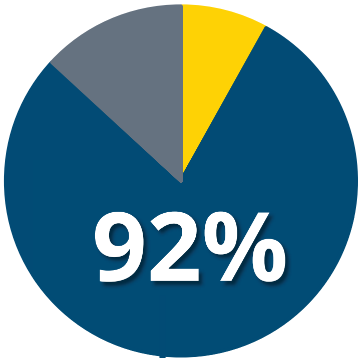
The survey objective was to gauge awareness of the Advanced Meter Early Adoption Program (AMS Opt In), as well as, understand what benefits of the program should be highlighted in marketing – by understanding what tools are valued among households who are participating in the program.

Methodology

- An online survey invite was sent on May 19th to members of the LG&E and KU Proprietary Customer Panel. The online survey was available to members from May 19th – May 31st.
- 1,070 members completed the 10-12 minute survey for a 54% response rate. Completes were among:
  - 666 (62%) KU customers
  - 404 (38%) LG&E customers

Summary of Findings

Summary of Findings – Non Participants



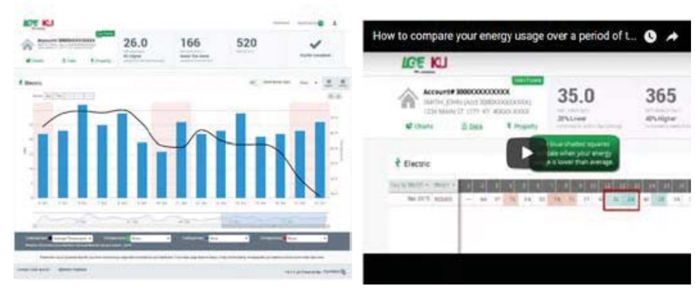
of households are ***NOT*** participating in the AMS Opt In Program.

Main reason for ***NOT*** participating…

79%

The vast majority of households are not participating because of a ***lack of awareness*** *(biggest barrier).*

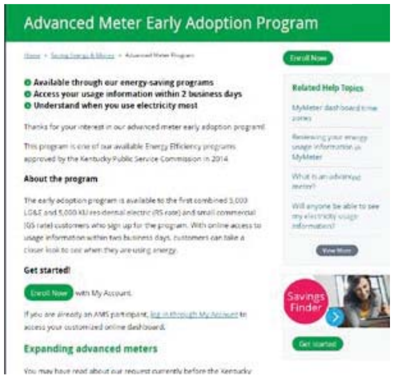
Likelihood to participate… **37%** of households report they are likely to participate in the AMS Opt In Program.



The majority of households who are likely to participate in the AMS Opt In program, find the information in ***"charts"*** as valuable (88%); followed closely by the information found in ***"data view"*** (83%).

With the ability to ***monitor*** and ***track*** energy consumption (i.e., ***determine peak times***), making ***adjustments*** to thermostats, appliances, and/or lighting are just some of the measures households report they would make if they participated in the AMS Opt In Program.

Summary of Findings - Participants



8% of households are participating in the AMS Opt In Program.

50% of participating households review their energy usage on the MyMeter dashboard at least ***once a month***.

The "charts" on the MyMeter dashboard is utilized most often – while the majority of participating households find the information in the charts valuable.

Conclusions & Recommendations

- Considering the vast majority of households are not aware of the AMS Opt In Program, simply increasing awareness with marketing efforts will likely increase participation.
  - *Recommendation: Consider a referral program or offering some type of incentive for participating to help increase awareness.*

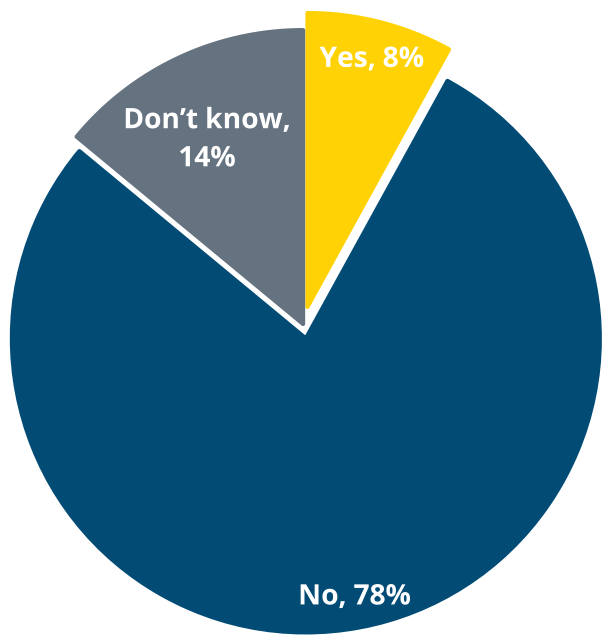
- Households who are and are not participating in the AMS Opt In Program value the information in the MyMeter dashboard; especially the information found in "charts" and "data" view.
  - *Recommendation: Highlight the valuable information found in the charts and data views on MyMeter dashboard - how can households can utilize the information to their benefit.*

- The ability to track, monitor, and control energy consumption is most compelling to households who are likely to participate in the AMS Opt In Program.
  - *Recommendation: Emphasize the ability households have in controlling their own energy consumption.*
  - *Recommendation: Outline what adjustments to energy consumption can be made compared to the effect those adjustments might have on their monthly bill.*

Detailed Survey Results

AMS Opt In Participation

- The vast majority of households do not participate in the AMS Opt In Program.



N=1,070

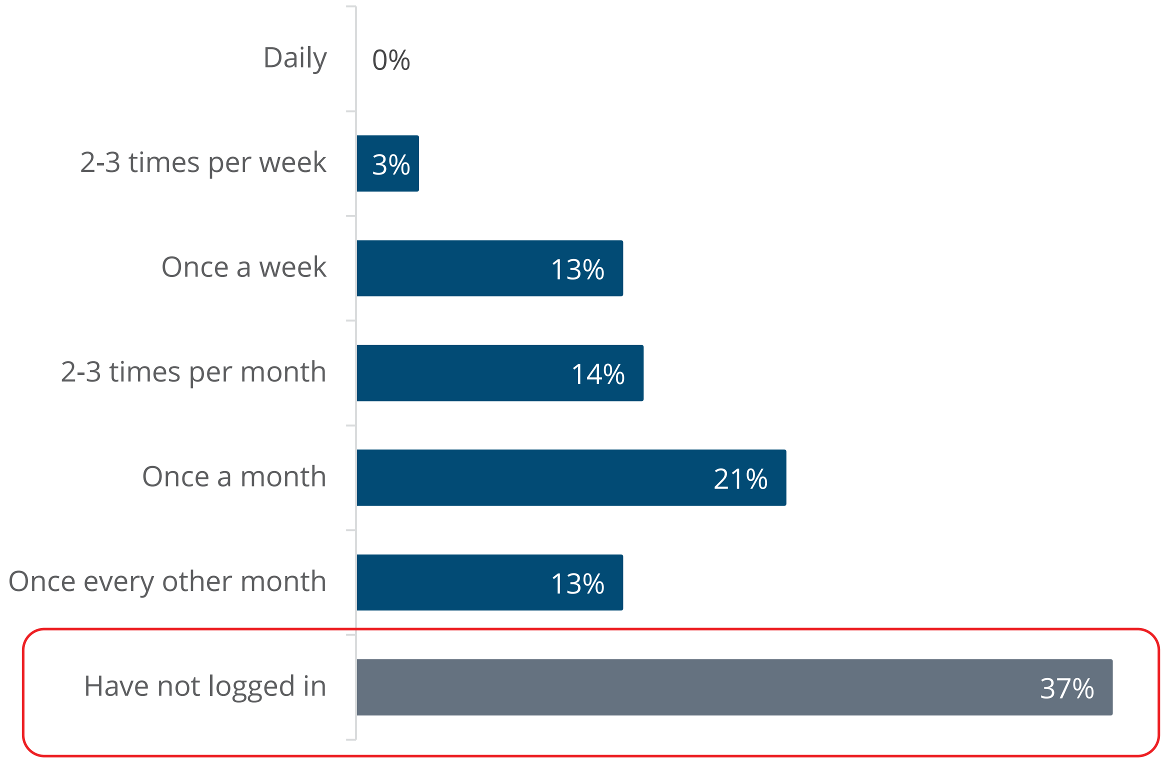
Q – Have you or anyone in your household participated in the Advanced Meter Early Adoption Program?

Detailed Survey Results:

AMS Opt In Program Participants

Frequency of Use: MyMeter Dashboard

- Half of participating households are reviewing their energy usage in the MyMeter dashboard at least once a month.
- However, slightly more than one-third of participating households have not logged in and reviewed their energy usage *(not fully participating).*

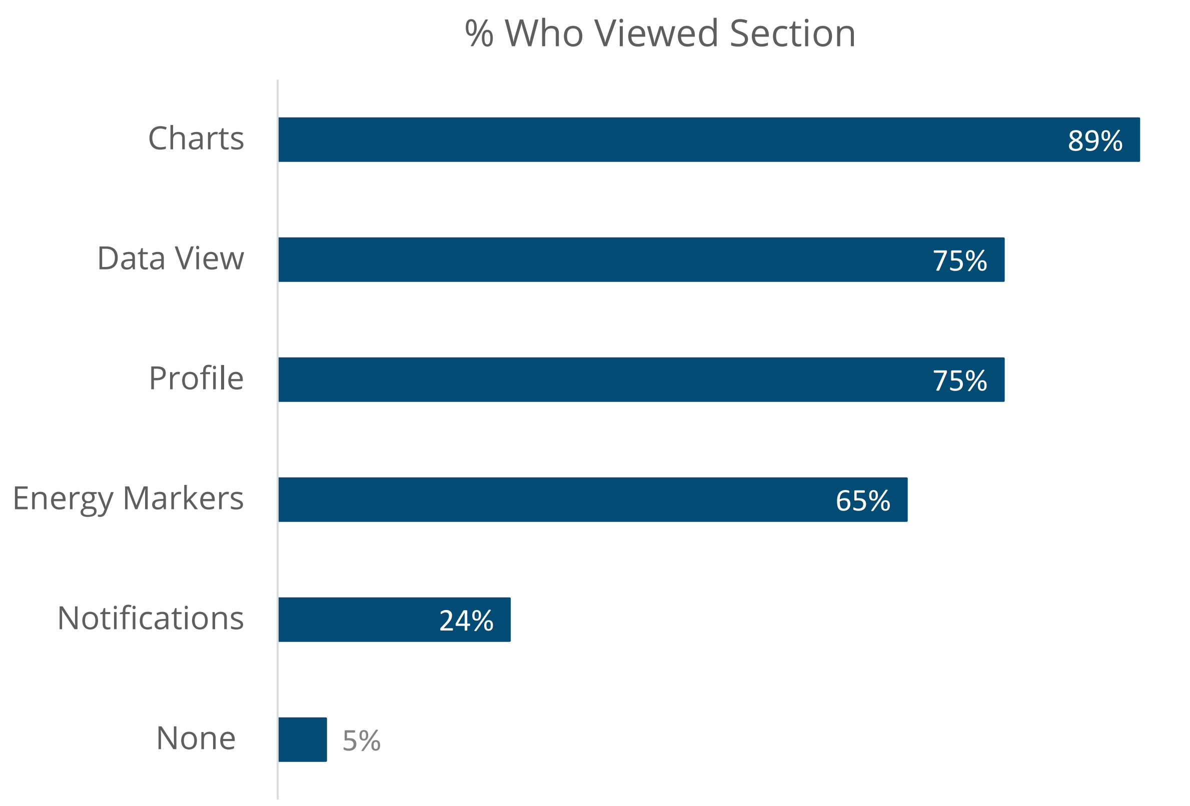


N=87

Q – How often would you say you log in and review your energy usage in your dashboard?

MyMeter Dashboard: Sections Viewed

- The "charts" in the MyMeter dashboard is viewed most often; followed by the "data" and the "profile" sections.

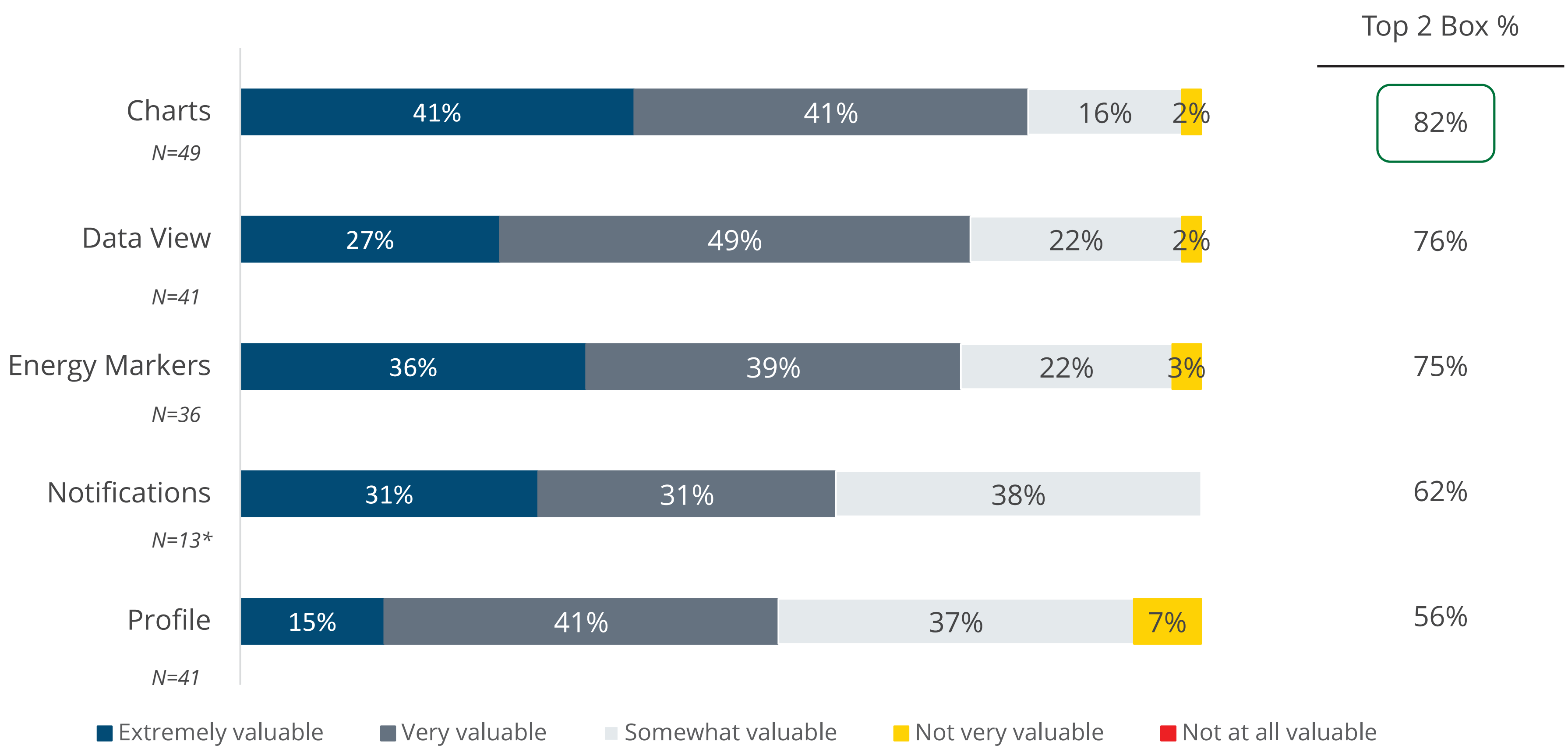


N=55

Q – Which of the following sections of the MyMeter dashboard have you viewed?

MyMeter Dashboard: Value of Information

- More than eight out of ten households value the information in "charts" on their MyMeter dashboard.

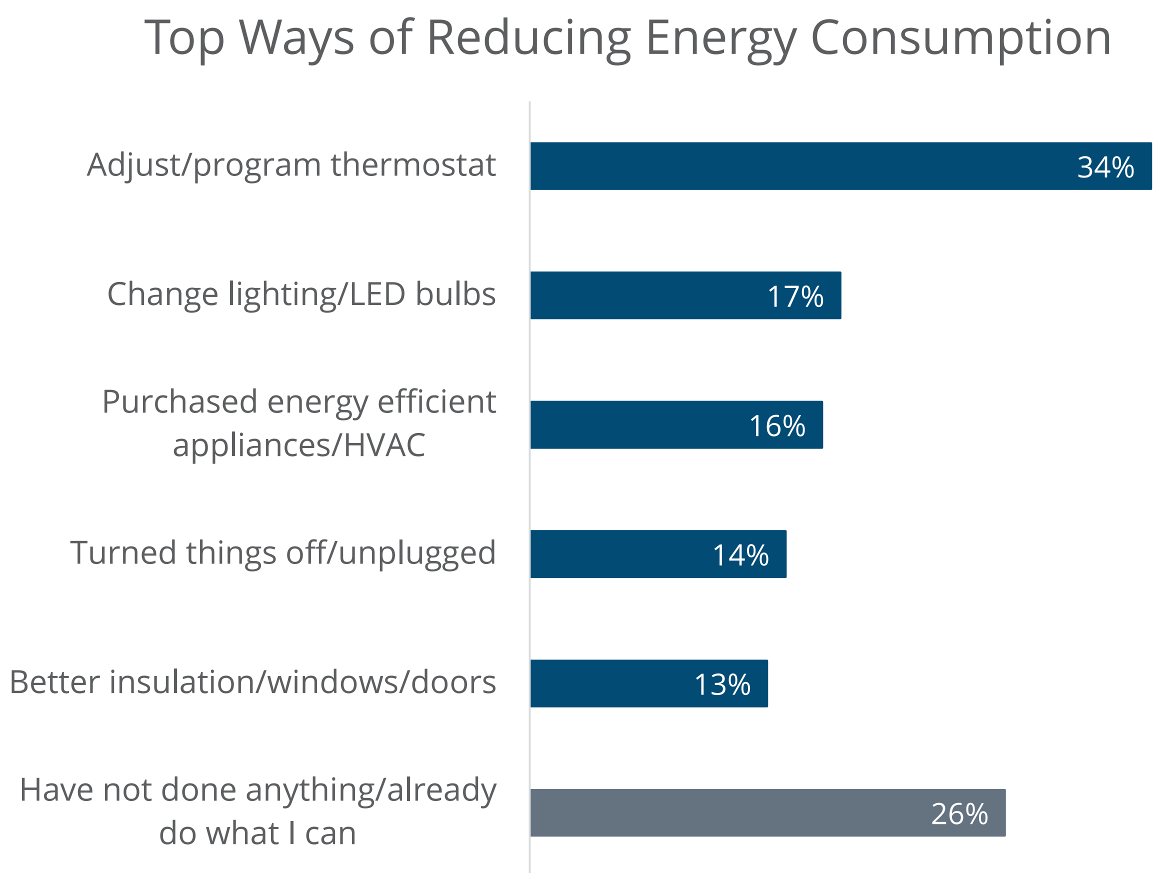


*Use caution when interpreting data due to small sample size

Q – How valuable is the information to you in each of the following MyMeter dashboard sections?

Reductions of Energy Consumption

- Since participating in the AMS Opt In Program, the highest percentage of households reported they have adjusted or programmed their thermostat as a way of reducing their energy consumption.



N=87

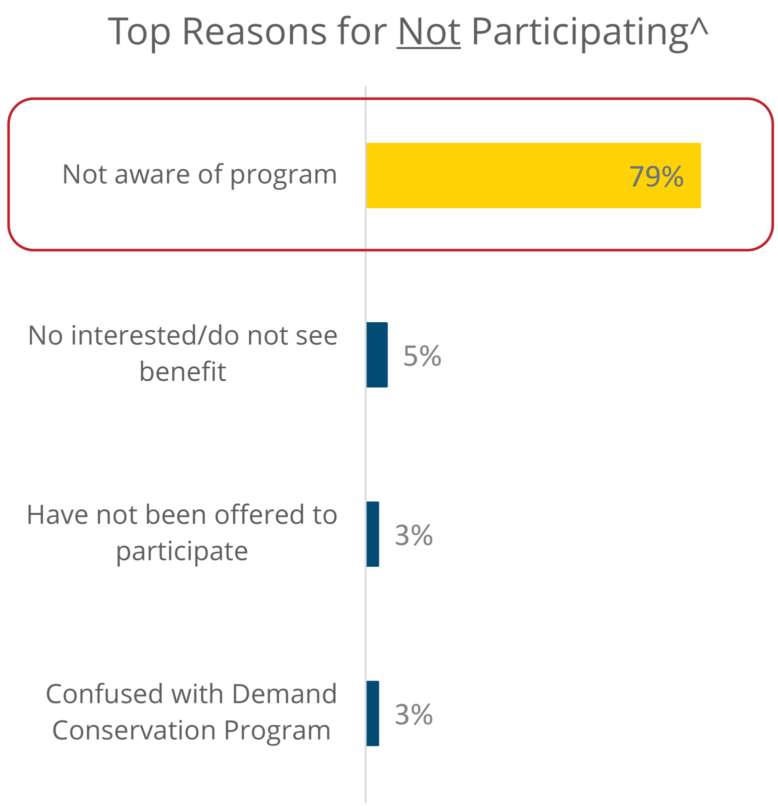
Q – Since participating in the Advanced Meter Early Adoption Program, what measures, if any, have you taken to reduce your energy consumption?

Detailed Survey Results:

AMS Opt In Program Non-Participants

Mains Reasons for Non Participation

- Lack of awareness, by far, is the main reason households are not participating in the AMS Opt In Program.



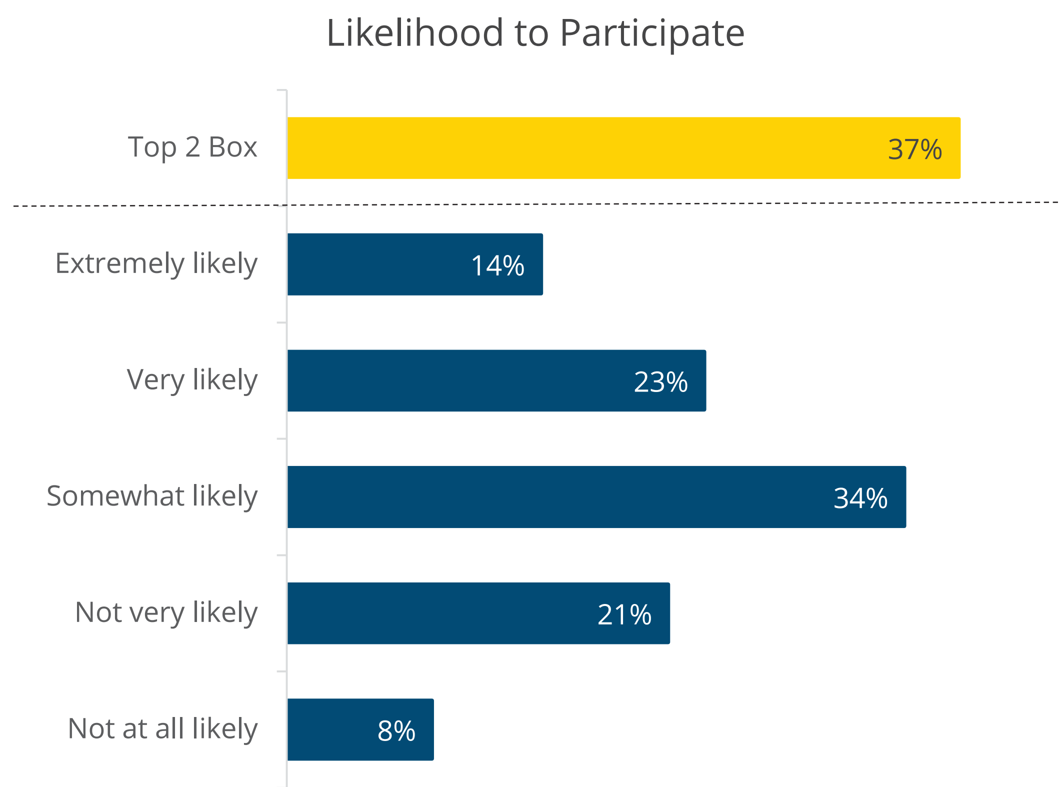
^Only Top Responses are displayed

N=983

Q – What is the main reason(s) why you have not participated in the Advanced Meter Early Adoption Program?

Likelihood to Participate in AMS Opt In Program

- Slightly more than one-third of households are likely to participate in the AMS Opt In Program.



N=983

Q – How likely would you be to participate in the Advanced Meter Early Adoption Program?

Reasons for Likelihood

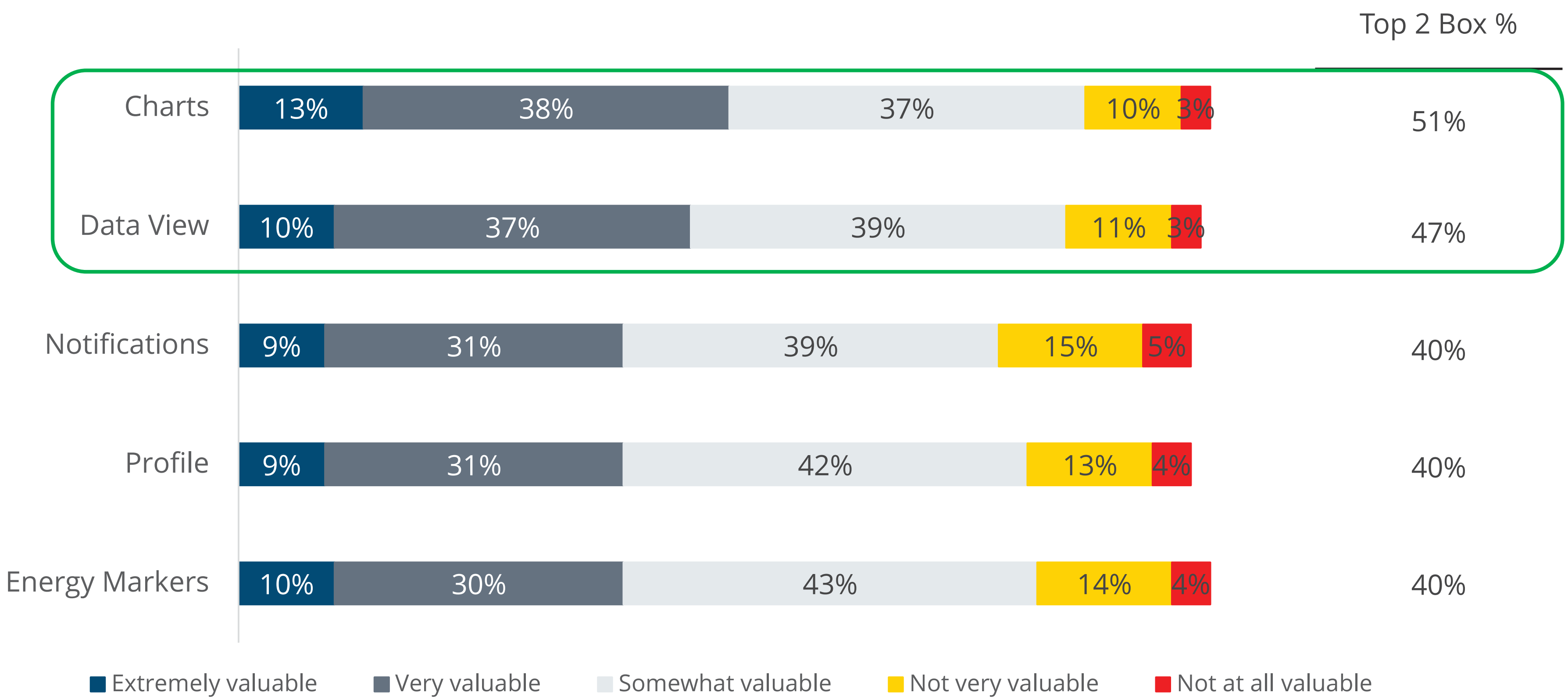
- Having the ability to track habits and/or usage is the main reason households would be likely to participate in the AMS Opt In Program.
- Already conserving and having no use for the program are cited most often as reasons for not being likely to participate.

Only Top Responses are displayed	Extremely/Very likely to Participate	Somewhat likely to Participate	Not very/Not at all likely to Participate
Ability to monitor/track habits/usage	66%	11%	2%
A way to save money/reduce usage	24%	9%	0%
Need more information about the program	2%	14%	2%
Already conserve/would not be of use	2%	22%	36%
Too timely/complicated	1%	19%	28%
Not interested/would not use information	0%	6%	21%

Q – Why are you [insert response] to participate in the Advanced Meter Early Adoption Program?

MyMeter Dashboard: Value of Information

- The information displayed in "charts" and "data" are valued most among non-participating households.



N=983

Q – How valuable is the information to you in each of the following MyMeter dashboard sections?

MyMeter Dashboard: Value of Information

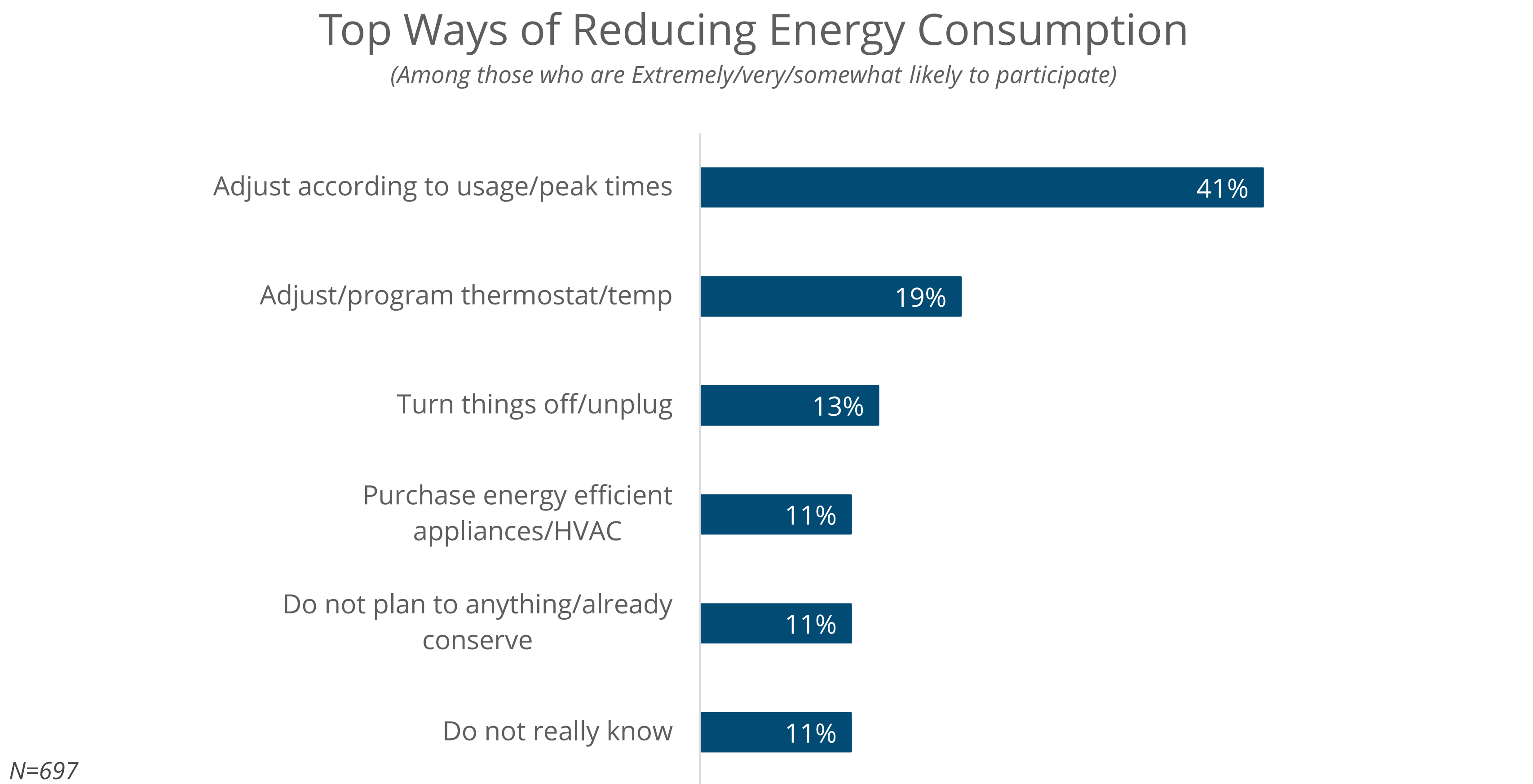
- The value of the information displayed significantly increases among households that are extremely or very likely to participate in the AMS Opt In Program – with information in the "charts" and "data" being of most value.

	Value of Information Top 2 Box % *(Extremely/Very Valuable)*	
	All Non-Participants	Extremely/Very Likely to Participate
Charts	51%	88%
Data View	47%	83%
Profile	40%	76%
Notifications	40%	75%
Energy Marker Tools	40%	75%

Q – How valuable is the information to you in each of the following MyMeter dashboard sections?

Reductions of Energy Consumption

➢ The highest percentage of non-participating households would make any adjustments they could according to their usage/peak times.

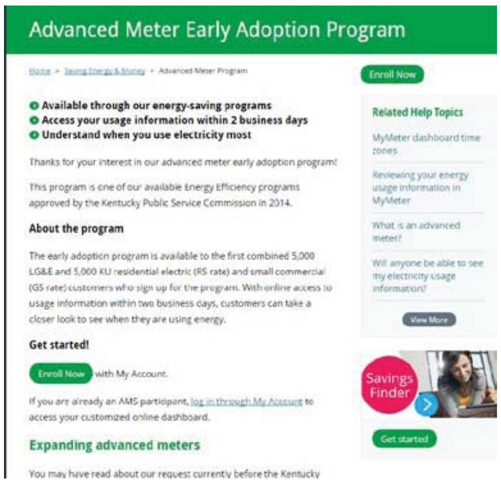


Q – If you were to participate in the Advanced Meter Early Adoption Program, what measures, if any, do you think you would take to reduce your energy consumption? (Among those who are extremely/very/somewhat likely to participate)

Detailed Survey Results:

DEMOGRAPHICS

Household Profile
Extremely/Very Likely to Participate



- ✓ *LG&E vs. KU customers – equally likely to participate*
- ✓ *Educated – with at least some college*
- ✓ *<50 years of age - significantly more likely to participate*

"We're retired and old and could care less about when we use our electricity most"

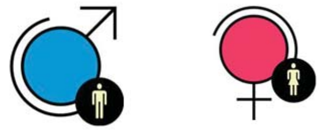
Demographics

Utility

LG&E 38%

KU 62%

Gender



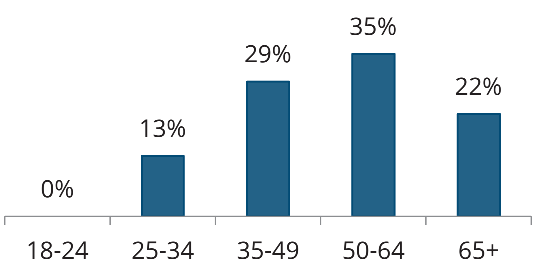
47% 53%

Residence

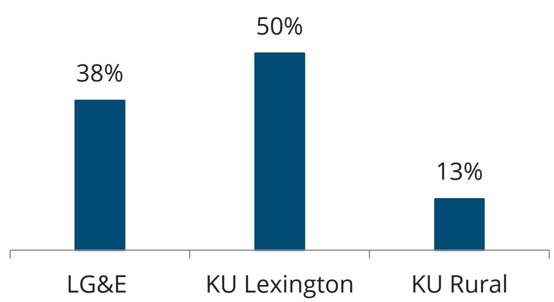
Own 88%

Rent 12%

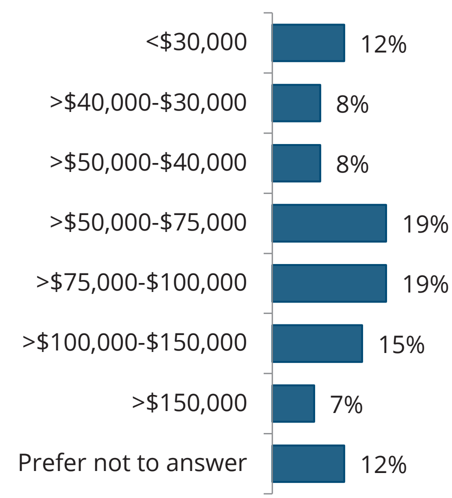
Age



Region



HH Income



N=1,070

**Due to rounding, may not add to 100%*

Appendix A-10

2017 Analysis of AMS MyMeter Active Users

Tetra Tech

TETRA TECH

To:	Greg Lawson, Kevin Craft, Jeff Myers, and Jonathan Whitehouse, LG&E and KU
Cc:	Rich Hasselman and Carrie Koenig, Tetra Tech
From:	Sue Hanson and Jonathan Hoechst
Date:	January 3, 2018
Subject:	AMS Opt-In Program Impact Evaluation - FINAL

This memo presents savings estimates for Louisville Gas and Electric Company and Kentucky Utilities Company's (LG&E and KU's) Advanced Metering Systems (AMS) Opt-In program. Consumption and participation data spanning the January 1, 2015 to August 31, 2017 timeframe was analyzed, while MyMeter user data spanned from September 7, 2015 to December 5, 2017. Findings are presented in the following main topic areas:

- Introduction and program description
- Executive summary
- Savings estimation methodology
- Findings.

INTRODUCTION AND PROGRAM DESCRIPTION

In January 2014, LG&E and KU proposed a voluntary AMS Opt-In program[1]. The initial deployment was limited to 5,000 LG&E and 5,000 KU residential and general service customers on a first-come-first-served basis, and included a website portal to display consumption data to customers. The primary purposes for proposing the AMS Opt-In program was to put in place the communications and control infrastructure necessary for possible future advanced-meter deployments, as well as to provide participating customers more detailed information about their consumption. The filing noted that "[n]ext generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home." The advanced meters LG&E and KU has deployed as part of the AMS Opt-In program meet these requirements. Additionally, the AMS Opt-in program served as a means to begin collecting data from participants in order to assess the potential for energy savings.

Based on a review of the 2013 Smart Grid Consumer Collaborative (SGCC) "Smart Grid Economic and Environmental Benefits" report[2], LG&E and KU expects that more detailed and timelier energy consumption information available to AMS device recipients through a web portal will lead to aggregate energy savings from these participants.

In November 2016, LG&E and KU proposed a full deployment of AMS across their service territory[3]. As part of the business case for deploying AMS to customers LG&E and KU had originally estimated an energy savings of 0.5 percent across all residential electric customers who receive advanced meter equipment. This percentage was based on an estimate that 17 percent of

[1] Case No. 2014-00003
[2] https://smartenergycc.org/wp-content/uploads/2013/10/SGCC-Econ-and-Environ-Benefits-Full-Report.pdf, Page 30
[3] KU Case No. 2016-00370 and LG&E Case No. 2016-00371

customers will engage with the equipment and the web portal in a meaningful way and that these customers will save, on average, three percent of their energy consumption. LG&E and KU had observed preliminary results from the AMS Opt-in program participants that supported the engagement estimate and based the three percent energy savings estimate to be conservatively below the 2013 SGCC report's findings. For the purposes of estimating an overall benefit of the equipment, this logic was applied only to residential electric customers' consumption. Thus, while it was planned for both residential and commercial customers to receive advanced meters, the aggregate consumption benefit was limited to 0.5 percent of residential consumption. Any possible additional energy consumption reduction by small commercial customers was not counted in LG&E and KU's analysis.

EXECUTIVE SUMMARY

Based on our analysis of consumption and participation data spanning January 1, 2015 through August 31, 2017, Tetra Tech recommends the impact of the AMS Opt-In program be estimated at 580 kWh per household, or 3.8 percent of annual consumption. Analysis presented in this memo also provides additional estimates of the potential savings achievable if AMS were deployed across all residential customers in LG&E and KU's service territory.

Using Google Analytics and other data files from the MyMeter web portal documenting user engagement, Tetra Tech's analysis resulted in average energy savings of 0.99 percent per AMS device. Based on Google Analytics MyMeter participant data, Tetra Tech found that 70.3 percent of AMS Opt-in program participants successful registered an account through the MyMeter ePortal, and of those, 37.2 percent became actively engaged users. Using these percentages, we estimated the aggregate savings of all residential advanced meter recipients to be:

$$0.703 \times 0.372 \times 0.038 = 0.0099$$

It is difficult to discern household-level savings that are small in magnitude compared to total consumption. In similar studies, some treatment households reduce consumption a lot, some only a little, and some actually increase consumption between the pre and post periods. The aggregate savings signal is easily lost in the variability in consumption from one household to another.

The AMS Opt-in program had a reasonably large treatment group from which to determine program effects; however the contrast group, made up of later program enrollees, was by default, smaller. Hence, looking only at the treatment group, one readily concludes that normalized consumption declined following opting into the program. The size of this decline, more than four percent of consumption, was eight times larger than the 0.5 percent reduction that LG&E and KU program planning had originally anticipated.

Consumption among the contrast group also declined during the pre/post period of this study. The reduction was small—small enough that we could not eliminate the statistical possibility that no reduction occurred. However, it is statistically more likely that some reduction among the contrast group occurred. The reasons for this reduction are unrelated to weather—which has been controlled for—but we cannot provide a definitive explanation for why they occurred. For example, participants may have purchased energy efficient equipment either as a course of normal equipment replacement or through LG&E and KU's energy efficiency programs.

SAVINGS ESTIMATION METHODOLOGY

OVERVIEW

In October 2016, Tetra Tech provided a preliminary estimate of program impacts, based on limited participation data. Tetra Tech conducted billing analysis on opt-in customers, including both a treatment and a contrast group. At that time, Tetra Tech identified 164 customers who had participated in the AMS Opt-in program long enough to have at least 10 months of post-AMS installation data, as well as 199 contrast group participants. For the current analysis, we analyzed an additional 12 months of billing data (i.e. 22 total months) and a larger number of program participants who had sufficient post installation data. Similar to the October 2016 analysis, Tetra Tech conducted a statistical billing analysis to estimate energy savings among households participating in the voluntary AMS Opt-In program. We analyzed data during two periods:

1. The period 1, from January 2015 through the billing month at each household *prior to* opting into the program. This represents the pre installation period, which we refer to simply as the "*pre*" period; and
2. The period beginning the billing month *following* the opt-in month at each household, through August 29, 2017. This represents the post installation period, or simply "post" period.

Households that had at least 12 months of pre installation data and 12 months of post installation data were named, collectively, the *treatment group*.

We also created a *contrast group* against which to compare program savings.[4] In this group were customers who enrolled in the AMS Opt-in program since the beginning of March 2017 and had at least 28 months of pre period consumption data that overlapped with the treatment group pre and post installation energy consumption data. For the contrast group, the pre and post installation period cutoff was defined as the median month between January 1, 2015, and the AMS device installation date (no earlier than March 2017). The pre installation period corresponds with the months prior to the household's median month of the billing period date range prior to AMS device installation, with the post installation period extending from the month following the median month to the month prior to AMS device installation. As a group, using the individual median months allows the contrast group to reflect post periods that overlap with the treatment group's range of post installation dates. For example, a household in the contrast group with an AMS device installation date of July 30, 2017 would be assigned a median month of April 2016. The pre installation period would correspond to January 2015-April 2016, and the post installation period would be May 2016-June 2017. Changes in consumption by the contrast group are then able to be compared to the changes in consumption of the treatment group.

The value of using program participants who enrolled after the end of the treatment group's post period as a contrast group is that, collectively, they are presumed to be more similar in the unmeasured attributes of participants—energy use, demographics, lifestyle—than would a general population sample, reducing the potential for selection bias to skew results. The limitation of using this group is that it is relatively small, so the estimates of change are expected to have greater uncertainty than a larger sample.

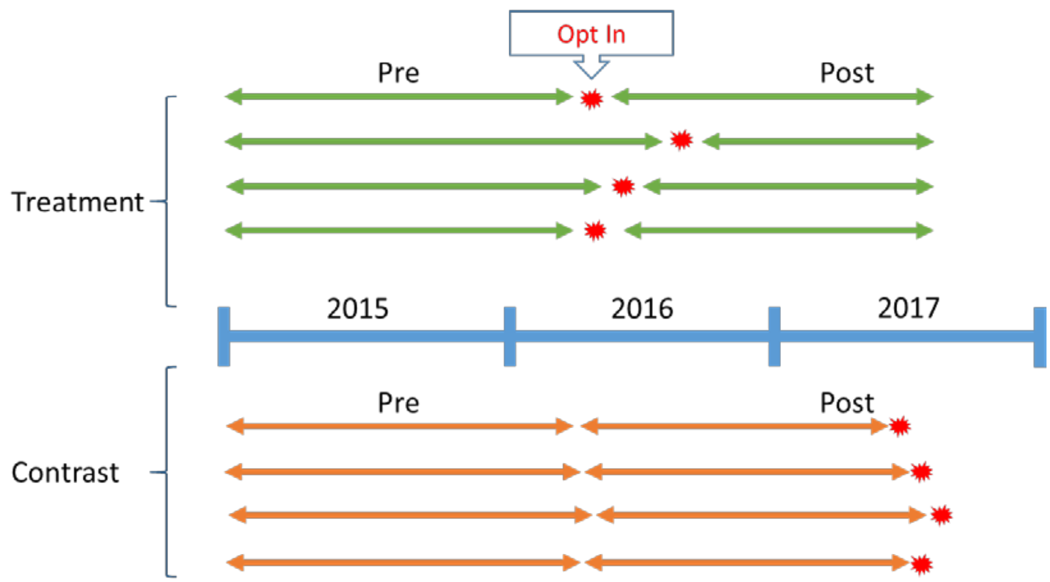
Figure 1 illustrates the relationship between the pre and post periods for the treatment and contrast groups. The treatment group is represented by the green bars above the timeline. For them, the pre period extends up to, but not including, the billing months during which an AMS device was

[4] We avoid the term "control group" because households were not randomly assigned.

installed. The post period excludes the installation months, and extends to the end of 2016. Participants in 2015 who closed their accounts before 12 months had passed following treatment, or who opened their accounts fewer than 12 months prior to treatment, were removed from the analysis. Thus, we have a minimum of 12 calendar months of data for all treatment customers in both the pre and post periods.

The contrast group, represented in Figure 1 by the orange bars below the timeline, includes customers who received their AMS device in 2016 but had at least 12 months of untreated data following the median installation date among the treatment group. Thus, 2016 participants who received AMS devices early in the year were excluded from the contrast group.

Figure 1. Pre and Post Periods for the Treatment and Contrast Groups



To estimate energy savings resulting from the AMS Opt-in program, Tetra Tech used a PRISM model, calculating the weather normalized average consumption in the pre and post period for each household, with the difference in annual consumption representing the program impact. We estimated a separate model for treatment and contrast groups and interpret the difference in variances between the two groups as the overall program impact. We also estimated a panel fixed effects regression model, which estimated impacts in the aggregate, across all households.

DATA COLLECTION

Tetra Tech received data[5] from LG&E and KU indicating account numbers for all residential customers participating in the AMS Opt-in program, including the date of enrollment and the date that AMS equipment had been installed. The equipment installation date was considered the participation date. The AMS Opt-in program participant file included information for 5,875 customers across both LG&E and KU service territories. Records included the billing periods ending between January 1, 2015 and August 31, 2017 (see Table 1).

Tetra Tech downloaded hourly temperature data from the National Oceanic and Atmospheric Administration's National Climatic Data Center[6] for the entire study period. We targeted two

[5] AMS Opt-in usage Jan 2015 – Aug 2017.xlsx.
[6] https://www.ncdc.noaa.gov/

weather stations, one at Louisville International Airport and one at Lexington Blue Grass Airport. From the hourly data we calculated a median daily temperature. Based on these data we calculated heating and cooling degree days by billing period. Tetra Tech also downloaded Typical Meteorological Year (TMY3) data from the National Renewable Energy Labs[7]. These data, representing hourly average temperature conditions for each weather station, were used to normalize changes in consumption between the pre and post installation periods and to provide a weather normalized result that would be applicable to typical annual weather conditions.

DATA SCREENING

We applied the following screening procedures to billing data to remove monthly data and entire households that might distort the findings.

- **Insufficient data.** Households with less than 12 months of pre or post period data were removed from the analysis because a full year of consumption data is highly preferred to accurately predict savings.
- **Extreme monthly consumption.** We removed commercial customers (those receiving electricity under GS rate categories), and subsequently removed the one percent highest and lowest energy consumers of the monthly consumption data. We retained households that had an adequate number of months of data after this screening.
- **Extreme consumption change between pre and post periods.** In the analysis, some households exhibited very high changes in consumption, indicating either increases in consumption or reductions in consumption. We eliminated the upper and lower one percent of the distribution of estimated annual changes in energy consumption. The households at the extremes were unlikely to reflect performance that would be generalizable to the population. With a relatively small sample, the extremes can bias the average results. Eliminating both high energy savers and high energy consumption increasers avoided the extreme changes from biasing the results in either direction.

Table 1 shows the effect on total sample size of each screening activity.

Table 1. Data Screening

Analysis Group	Number in Sample
Initial Sample	5,108
(Treatment Group) Have 12 months consumption data post opt-in and at least 24 months total	2,569
(Contrast Group) Have no more than 4 month data post opt-in and at least 28 months total	428
(Treatment Group) Extreme Change in Estimated Annual Pre/Post Consumption	116
(Contrast Group) Extreme Change in Estimated Annual Pre/Post Consumption	57
Total Treatment Group in Analysis	**2,453**
Total Contrast Group in Analysis	**371**

[7] http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3

HEATING AND COOLING DEGREE DAYS

Heating degree days (HDD) are the difference between a reference temperature and the average daily temperature on a given day. The reference temperature represents the point at which heating equipment begins to operate. Cooling degree days (CDD) are the difference between the average daily temperature on a given day and a reference temperature that represents the point at which cooling equipment begins to operate.

$$HDD = ReferenceTemp - AverageDailyTemp$$

$$CDD = AverageDailyTemp - ReferenceTemp$$

HDD and CDD can be summed across days for a monthly or annual value. For our model, which estimated average daily consumption, we calculated the average daily HDD and CDD for each billing period.

To determine the appropriate reference temperature for LG&E and KU customers, we estimated separate heating and cooling regression models for each household in both the pre and post periods. Each model allowed the heating or cooling reference temperature to range from 40°F to 90°F for each household, in both the pre and post periods. The base temperature resulting in the best model fit (R^2) was assigned to the household.

For customers whose consumption was relatively insensitive to HDD or CDD—that is, for whom either the heating or the cooling models fit the data poorly—we assigned HDD = 0 or CDD = 0, or both, rendering the model a cooling only, heating only, or an intercept only model. The intercept only model in effect compares the mean average daily consumption in the pre and post periods, without adjusting for weather differences and reflects households without statistically significant changes in consumption due to weather.

PRISM MODEL

We estimated heating and cooling PRISM models in both the pre and post period for each customer in the treatment and contrast groups using the following specification:

$$ADC_{it} = \alpha_i + \beta_1 AVGHDD_{it} + \beta_2 AVGCDD_{it} + \varepsilon_{it}$$

Where for each customer '*i*' and day '*t*':

ADC_{it} = Average daily kWh consumption in the pre or post program period.

α_i = The participant intercept, representing the average daily kWh baseload.

β_1 = The model space heating parameter, used in the heating only, and heating/cooling models. This represents the average change in daily usage resulting from an increase of one daily HDD.

$AVGHDD_{it}$ = The base 40°F to 90°F average daily HDD for each location, used in the heating only and heating/cooling models

β_2 = The model space cooling parameter, used in the heating only, and heating/cooling models. This represents the average change in daily usage resulting from an increase of one daily CDD.

$AVGCDD_{it}$ = The base 40°F to 90°F average daily cooling degree days for each location, used in the cooling only and heating/cooling models.

ε_{it} = The error term.

Using this model, we calculated normalized annual consumption (NAC), solving for typical annual HDD and CDD based on daily TMY3 data and summing across the 365 days in the year. For each of the analysis groups—treatment pre, treatment post, contrast pre, contrast post—we calculated an average NAC. The program impact, as a percentage of the treatment pre-NAC is:

$$percent\ savings = \frac{preNAC_t - postNAC_t}{preNAC_t} - \frac{preNAC_c - postNAC_c}{preNAC_c}$$

Where the subscript "*t*" represents the treatment group and the subscript "*c*" represents the contrast group.

FIXED EFFECTS PANEL REGRESSION MODELS

As is our standard practice, we also ran fixed-effects panel regression models as a second approach to the estimation of program impacts. These models performed poorly, with our typical model specifications indicating no consumption reductions between the pre and post periods and only very simple models indicating any savings. We attribute this performance level to the relatively small size of savings per household as a percent of consumption and to the relatively weak relationship between weather and consumption in a substantial number of households. As is our normal practice, we reported savings for the type of model with the highest precision around the estimate, which is the PRISM model.

GOOGLE ANALYTICS AND MYMETER REPORTING

Tetra Tech received and reviewed AMS Opt-in program Google Analytics data and MyMeter user activity reporting from LG&E and KU. The dataset containing MyMeter account activity[8], which included all user activity (e.g. MyMeter account registration, successful logins, etc.) within the MyMeter ePortal between September 7, 2015 and December 5, 2017. For those program participants with AMS devices but who had not registered for a MyMeter account, no MyMeter activity was recorded. In addition, records without valid account numbers were removed from the analysis file, as they were attached to names of LG&E and KU staff or administrative accounts used to monitor the ePortal website and perform maintenance (i.e. not actual users of the MyMeter ePortal).

Tetra Tech defined eligible account activity as either of two activities—successful registration or successful logins, based on the logic that any user must first create an account to use the site, and after that, anytime the user wishes to use *any* of the features within the MyMeter website, he/she must first successfully login before navigating to specific sub-sites. Users that accessed the MyMeter ePortal at least six times were defined as actively engaged customers.

[8] LKE Portal Activity w Account Number 12_5_17.xlsx.

FINDINGS

This section documents the details in our approach to estimating savings using three determining factors: 1) the rate of enrollment in the program (i.e., the percentage who sign up for the ePortal); 2) the percentage of enrollees who actively engaged; and 3) the average savings of actively engaged customers. A discussion of each of these three factors follows.

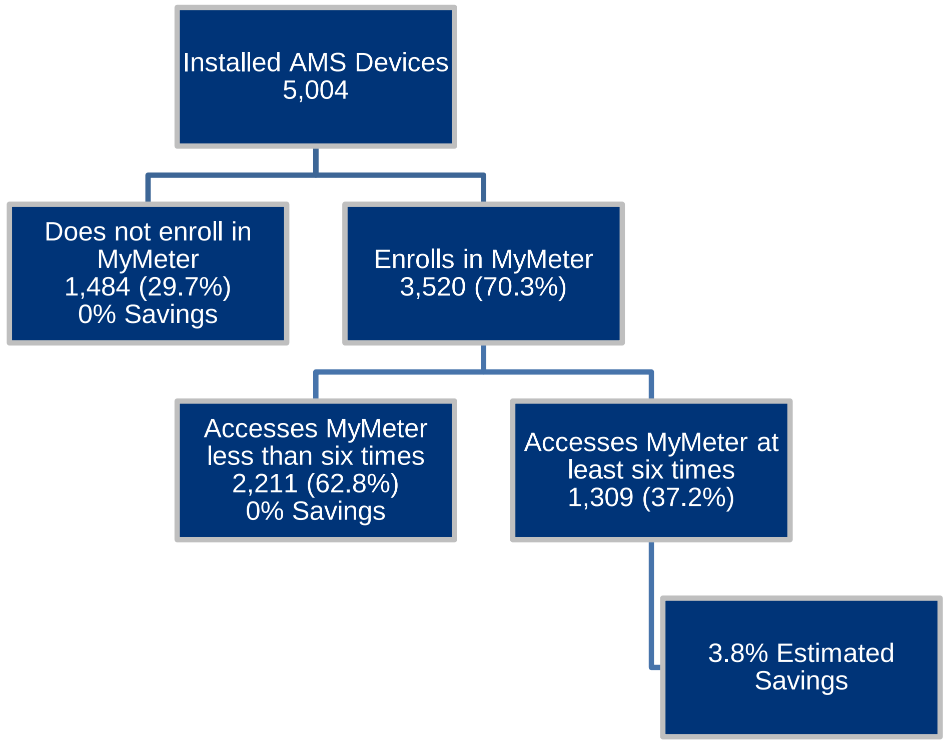
RATE OF ENROLLMENT AND ACTIVE ENGAGEMENT

Compared with previous estimates provided in October 2016, the percentage of AMS Opt-in participants that successfully registered a MyMeter account has grown from less than half (48 percent) to 70.3 percent, while the percent of registered users with at least six logins remained stable (36.0 percent in 2016, 37.2 percent in 2017). The increased enrollment in MyMeter results in a savings estimate that is almost twice as large as the previous savings estimate—0.99 percent compared to 0.52 percent. The rate of MyMeter enrollment among AMS Opt-in participants, the percentage of actively engaged users, and the previously estimated average energy savings among program participants are summarized in Table 2. In addition, Figure 2 provides a tree diagram to visually show the decision points in the savings estimation methodology.

Table 2. AMS Opt-In Participation and MyMeter Summary Statistics

AMS Opt-In Participant Subset	Number / Percent
Accounts with installed AMS device (through Sept. 15, 2017)	5,004
Registered MyMeter users	3,520
Percent of AMS participants that created a MyMeter account	**70.3%**
Registered MyMeter users with at least six logins	1,309
Percent of MyMeter users with at least six logins	**37.2%**
Average Energy Savings of AMS Opt-In Participants	**3.8%**

Figure 2. AMS Opt-In Participant Savings Tree Diagram



BILLING DATA ANALYSIS

The PRISM analysis indicated average household energy savings of approximately 4.5 percent compared with the pre-installation period among households in the treatment group. Consumption among households in the contrast group fell about 0.7 percent compared to pre-installation levels during the same period. The results for each analysis group are shown in Table 3.

Table 3. PRISM Analysis Normalized Annual Consumption

Analysis Group	n	NAC (kWh)
Treatment – pre period	1,353	15,233
Treatment – post period	1,353	14,451
Contrast – pre period	357	15,683
Contrast – post period	357	15,568

The treatment group reduced its NAC between the pre and post periods by an average of 692 kWh, or about 4.5 percent. The contrast group, however, reduced its NAC during this time by 115 kWh, or about 0.7 percent of a slightly higher baseline consumption. Thus, we estimated the average impact of the AMS Opt-In program to be 3.8% x 15,233 kWh = 580 kWh.

Based on these findings, the program impact as a percentage of pre treatment consumption, is:

$$3.8\% = \frac{15{,}233 - 14{,}451}{15{,}233} - \frac{15{,}683 - 15{,}568}{15{,}683}$$

We estimated the 90 percent confidence interval around treatment group savings to be +/- 12 percent of the estimated value. Thus, the lower limit to the NAC for the treatment group is 609 kWh, or 4.0 percent of pre period NAC. Relative uncertainty around the contrast group impact was higher because the sample size was smaller and the impact was close to zero. We estimated the 90 percent confidence interval around the contrast group to be +/- 20 percent of 115 kWh.

To estimate uncertainty around the adjusted impact from the treatment and contrast samples we used a resampling approach. We drew 1,000 random participants, with replacement, from each group and estimated the combined impact. The distribution of this impact is an approximation of the uncertainty around the point estimate of the program impact as a percentage of pre treatment consumption. From this activity we estimated that the 90 percent confidence interval around the adjusted impact is +/- 0.9 percentage points, for a relative precision of +/-22 percent.

Appendix A-11

AMS Glossary

Acronym Glossary

Acronym	Meaning
ADA	Advanced Distribution Automation
ADMS	Advanced Distribution Management Systems
AHE	AMS Head-End
AMS	Advanced Metering Systems
BPEM	Business Process Exception Management
CAPEX	Capital Expenditure
CIS	Customer Information System
CO2	Carbon Dioxide
CSRs	Customer Service Representatives
CT	Current transformer
DA	Distribution Automation
DERMS	Distributed Energy Resource Management Systems
DERs	Distributed Energy Resources
DMS	Distribution Management System
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
ePortal	Web Portal Presentment
FAN	Field Area Network
FLISR	Fault Location, Isolation and Service Restoration
GHG	Greenhouse gas
GIS	Geographic information system
HAN	Home Area Network
IEDs	Intelligent Electronic Devices
IHD	In-home device
IOUs	Investor Owned Utilities
IT	Information Technology
IVR	Interactive voice response
KPSC	Kentucky Public Service Commission
KU	Kentucky Utilities
LG&E	Louisville Gas & Electric
MAM	Meter Asset Management
MDMS	Meter Data Management System
MOC	Metering Operations Center
NPV	Net present value
O&M/ OPEX	Operations and Maintenance
OMS	Outage management system
PEVs	Plug-in electric vehicles
PON	Power outage notifications
PPLEU	PPL Electric Utilities
PRN	Power restoration notifications
PT	Potential transformer
PV	Photovoltaics
RF Mesh	Radio Frequency
SCADA	Supervisory Control and Data Acquisition
SGCC	Smart Grid Consumer Collaborative
SMS	Short Message Service

Acronym	Meaning
TOD/TOU	Time of Day /Time of Use
VEE	Validate, Estimate, and Edit
VVO	Volt/VAR Optimization
WAN	Wide Area Network

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

<table>
<tr><td>ELECTRONIC JOINT APPLICATION OF
LOUISVILLE GAS AND ELECTRIC
COMPANY AND KENTUCKY UTILITIES
COMPANY FOR CERTIFICATES OF
PUBLIC CONVENIENCE AND NECESSITY
FOR FULL DEPLOYMENT OF ADVANCED
METERING SYSTEMS</td><td>)
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)</td><td>CASE NO. 2018-00005</td></tr>
</table>

TESTIMONY OF
DAVID E. HUFF
DIRECTOR OF CUSTOMER ENERGY EFFICIENCY
AND EMERGING TECHNOLOGIES
LG&E AND KU SERVICES COMPANY

Filed: January 10, 2018

Q. Please state your name, position, and business address.

A. My name is David E. Huff. I am Director of Customer Energy Efficiency and Emerging Technologies for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualifications and work experience is attached as Appendix A.

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

A. Yes. I testified most recently in the Companies' most recent demand-side management and energy-efficiency program portfolio application proceeding, Case No. 2017-00441, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Companies' participation in and the results of the Advanced Metering Systems ("AMS") Collaborative.

Q. Are you supporting any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit DEH-1 AMS Collaborative Session 1 presentation by Companies and summary slides of session

Exhibit DEH-2 AMS Collaborative Session 2 presentation by Companies and summary slides of session

Exhibit DEH-3 AMS Collaborative Session 3 presentation by Companies and summary slides of session

Exhibit DEH-4	AMS Collaborative Session 4 presentation by Companies and summary slides of session
Exhibit DEH-5	AMS Collaborative Session 5 presentation by Companies and summary slides of session
Exhibit DEH-6	Learnings from the Collaborative

Also, I am co-sponsoring the AMS Opt-Out Special Charges tariff provisions and cost support in Exhibits REL-1 (KU), REL-2 (LG&E electric) and REL-3 (LG&E gas) to the testimony of Rick E. Lovekamp.

AMS COLLABORATIVE

Q. Please briefly describe the AMS Collaborative.

A. As Mr. Lovekamp describes in his testimony, the Companies agreed in the First Stipulation in their 2016 base-rate cases to initiate an AMS Collaborative involving the Companies and all interested parties to the rate cases to discuss and to seek to address any concerns about AMS.[1] The AMS Collaborative consisted of five day-long sessions about AMS, of which the first was held less than a month after the Commission's final orders in the Companies' 2016 base-rate cases. Based on the participants' input provided in the first meeting, the Collaborative addressed in the four subsequent sessions AMS costs and benefits, data privacy and sharing, data empowerment, customer education, remote service switching, and new services AMS could enable. Representatives from the Companies led, facilitated, and participated in all of the Collaborative meetings, listening to the Collaborative participants' interests,

[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017).

concerns, and questions about AMS, and providing detailed information about and explanation concerning the AMS proposal. In addition to informing and educating the other Collaborative participants, the meetings allowed the Companies to better understand participants' concerns. Likewise, Collaborative members learned how customers can benefit from the deployment of AMS.

Q. What was your role in the AMS Collaborative?

A. I participated in the development of materials presented at the AMS Collaborative meetings and also led, assisted in the facilitation, and participated in the discussion at each of the five meetings.

Q. Which entities participated in the AMS Collaborative?

A. The AMS Collaborative was open to all 2016 rate case participants; those that chose to attend represented a broad array of customer interests. Participants in at least one of the five AMS Collaborative meetings included representatives from the Office of the Attorney General; Association of Community Ministries, Inc.; BellSouth Telecommunications, LLC d/b/a AT&T Kentucky; the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc.; Kentucky School Boards Association; Kentucky Industrial Utility Customers, Inc.; Lexington-Fayette Urban County Government; Louisville/Jefferson County Metro Government; Metropolitan Housing Coalition; and Sierra Club. As I described above, representatives of the Companies also facilitated and fully participated in the AMS Collaborative.

Q. Please describe the first session of the AMS Collaborative.

A. The first session was held in Lexington on Tuesday, July 18, 2017. The session's focus was to identify participants' interests regarding AMS and to engage participants in setting the agenda for subsequent meetings. To that end, Collaborative participants divided into small work groups and responded to a series of questions to identify their concerns, needs, and questions regarding AMS generally and more specifically the Companies' 2016 proposal for full AMS deployment. Discussion topics from the smaller groups were shared with the full group, sparking additional discussion and defining topics for future meetings. Collaborative participants ultimately selected a number of themes to discuss in later sessions, including:

- Costs: How did the Companies derive the costs and benefits of AMS, and how will they impact customers? Will low-income customers pay more? Will new rates be a part of AMS?
- Data Privacy and Sharing: Who will be able to access the collected data? How will it be kept secure? Will it be shared with others?
- Data Empowerment: How will the Companies and others use the data from AMS? Who will be able to use this data?
- Education: What information will be shared with customers about AMS prior to deployment? How will the Companies communicate with customers about AMS?
- Remote Service Switching: Will the remote service switch lead to more customer disconnections?
- New Services: What other services can the Companies provide using the data from AMS?

Collaborative participants were also asked to sequence the general themes and agree upon the order in which the Collaborative would address these topics in future sessions. The group agreed on the following order and estimated time needed for the first four monthly meetings:

- Cost Benefit Baseline - Full day

- Data Privacy/Sharing - ½ day
- Data Empowerment - ½ day
- Education - ½ day
- Remote Disconnect/Reconnect - ½ day
- New Services - ½ day
- Cost Benefit Recap - ½ day

Over the course of the Collaborative, the Companies suggested changes to the above schedule and timeframes, resulting in the following schedule:

- Session 1 – Identifying topics and sequencing
- Session 2 – Review of the Business Case from the November 2016 filing
- Session 3 – Data Privacy / Sharing, Data Empowerment, and Customer Education
- Session 4 – Opt-out, Remote Service Switch, and New Services
- Session 5 – Review of Business Case changes

The activities in Session 1 included two main insights. First, as participants shared their specific positions on different aspects of an AMS program, participants realized that their interests and positions may not align with all intervenors and, in some cases, may actually oppose another's position. Second, the dynamic identified between data privacy and data use was much more complex than initially thought.

Q. Describe the second session of the AMS Collaborative.

A. The second session was held in Louisville on Tuesday, August 22, 2017. This session covered the costs and benefits of AMS deployment and discussed the Business Case as originally filed. Session 2 began with an introduction and a review of the various technologies and projects the Companies have previously implemented, including the Power Line Carrier Metering technologies, Responsive Pricing and Smart Meter Pilot, Downtown Network, and the AMS Customer Service Offering (also called the Opt-In program) offered to customers today.[2] To provide participants with a common baseline of knowledge and terminology, representatives of the Companies then gave an overview of the workings of an AMS system, including allowing participants to physically view electric meters, gas modules, and communication hardware. Representatives of the Companies also demonstrated the current ePortal "MyMeter" system and highlighted the capabilities and usage that are available today with the Opt-In program. The Collaborative also thoroughly reviewed the costs and benefits of AMS deployment as shown in the Companies' 2016 base rate cases, including a detailed explanation of each cost and benefit category. The Collaborative also addressed questions from participants, such as the prevalence of smart meters across the United States and the average book life of meters that are to be retired. Some participants questioned the validity of the Companies' assumptions and estimates of costs and benefits, while others indicated they thought the Companies had made reasonable engineering estimates. The Companies sought to address all questions and issues raised by participants.

Q. Describe the third session of the AMS Collaborative.

A. The third session was held in Frankfort on Tuesday, September 20, 2017. This session covered three topics: (1) Data Privacy/Sharing, (2) Data Empowerment, and (3) Education. First, the discussion of data security, privacy, and sharing began with

[2] These projects are more fully described in section 3 of the AMS Business Case attached to Mr. Malloy's testimony as exhibit JPM-1.

a high-level overview of the technologies, processes, and practices in place today that support the Companies' corporate information security strategy and privacy policies. Next, representatives from the Companies discussed the protections in place for consumer data, including AMS-specific data. Representatives also explained that privacy is of paramount importance to the Companies and customer information is only provided on an as-needed basis even between departments within the utility. A demonstration of the Low-Income Portal, a channel for advocates to assist low-income customers with financial support, provided participants insight into the security and privacy measures that the Companies take today to support customer information sharing with external groups. The Collaborative also discussed the ability of customers to enable access for third parties through defined processes or provide their usage data directly to third parties through exports from "MyMeter." In this section, participants raised concerns relating to data privacy policies being established solely by the Companies without external oversight or review. It was highlighted that outside groups are developing guidelines and standards that the Companies could leverage to increase consumer confidence.

Second, the Data Empowerment section compared monthly usage information shared today through the customer bill to the more granular interval data available through an AMS system and portal. A small group exercise asked participants to suggest solutions to challenges that various populations may have in accessing AMS data (e.g., low income customers who have less access to technology and seniors who may need caregiver assistance). In addition, a participant suggested that consumer data, including anonymous data, may offer the Companies new revenue opportunities.

The participant suggested such revenues could be used to offset costs to customers associated with AMS.

Third, during the Customer Education discussion, the Companies shared their plan to inform and educate their customers on the benefits, changes, and choices that will result from AMS, building both general awareness and energy literacy.

Q. Describe the fourth session of the AMS Collaborative.

A. The fourth session was held in Frankfort on Tuesday, October 17, 2017. This session's main topics addressed an AMS opt-out program, including the potential fees and complexities associated with such a program, and Remote Service Switching. Part of the Collaborative discussion of opt-out focused on Case No. 2012-00428, an administrative proceeding to consider the implementation of smart grid and smart meter technologies,[3] and recent rulings, including the addition of an opt-out to the recently approved Duke Energy Kentucky's ("Duke Kentucky") advanced metering deployment program.[4] Representatives of the Companies explained that opt-out provisions were not included in the initial 2016 filing based in part on language in the Commission's order in Case No. 2012-000428, which stated that opt-out provisions reduce the maximum benefits of AMS. Based in part on the Commission's approval of the opt-out option in the Duke AMI program, the Companies explained that they are now amenable to an opt-out option and sought feedback from Collaborative participants. Based on language from Case No. 2012-00428, representatives of the

[3] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 17 (Ky. PSC Apr. 13, 2016).

[4] *In the Matter of: Application of Duke Energy Kentucky, Inc. for (1) a Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief*, Case No. 2016-00152, Order (May 25, 2017).

Companies advised that it would be likely that participants who choose to opt out would be responsible for the costs associated with opting out. Representatives of the Companies also ensured participants that any one-time and monthly fees would be cost-based and not punitive. Through the discussion, the necessary communication, timing issues, and fees brought to light the complexities of an opt-out program for both customers and the Companies. Although an opt-out program introduces complexity and some additional uncertainty into the proposal, the Companies accepted the desire of some Collaborative members to have both an opt-out provision and to initially waive the set-up fee for those wishing to opt-out prior to deployment of advanced meters but only during the initial deployment.

The Collaborative also discussed Remote Service Switching for electric service that AMS would enable. An overview of current practices informed Collaborative participants concerning current processes and the changes that could result from Remote Service Switching. Participants voiced questions and concerns about various aspects of remote disconnections including: that low-income customers were likely to be disconnected in greater numbers; whether disconnections would be suspended during extreme temperatures; procedures when customers were still in the process of obtaining assistance; protections for customers on oxygen or other medical devices; notification and timing. The Companies provided information on a review of the historical number of disconnections and potential future processes. Participants also shared feedback regarding their preference for disconnections to occur over a time range to help manage agencies' office traffic and support.

The Collaborative also discussed new services and tools that could be developed through AMS and solicited feedback on education. Participants suggested enhancements to the ePortal, also referred to as "MyMeter," and related systems to allow customers to access near-real-time usage information and programs to enable property managers and builders to use data to improve properties and support financing for improvements. The Collaborative also discussed the need for information to be communicated in multiple formats and different comprehension levels in order to educate all customers about AMS.

Q. Describe the fifth session of the AMS Collaborative.

A. The fifth session was held in Frankfort on Wednesday, November 8, 2017. This session focused on a review of the revised business case for full deployment of AMS. The Companies also outlined their plans for making this filing for CPCN authority for the full AMS deployment. At least some participants believed it was important to note that the Companies' decision to seek CPCN authority at this time does not reflect either support for or opposition to the filing on the part of the participants. There were also follow-up discussions concerning possible future service offerings enabled by AMS, concerns and protections regarding use of Remote Service Switching, and terms and charges regarding opting out of AMS.

Q. Did the AMS Collaborative fulfill the objectives identified in the First Stipulation?

A. Yes. The Companies endeavored to discuss and address any participant concerns about AMS in the Collaborative. The process was thorough, robust, and fulfilled the objectives of the AMS Collaborative identified in the First Stipulation, consuming 40 hours over five different day-long meetings. The Companies took the AMS Collaborative process seriously and believe the Collaborative helped educate participants on the benefits of AMS and shape a better proposal.

Each AMS Collaborative session had a visual facilitation graphic along with a PowerPoint which summarized the session. Both of these items were emailed to both the active participants and the participants who wanted to stay abreast of the discussions but elected to not attend the meetings. In total about 150 to 200 PowerPoint slides were created and reviewed with the Collaborative participants.

After the fifth session a summary document was prepared and shared with the participants. Some participants submitted edits, changes, and additions to the document. The final document is a comprehensive summary of the full AMS Collaborative process and reflects the participants' positions on various AMS issues discussed in the meetings. As shown in that document (attached as Exhibit DEH-6) and the documents related to each AMS Collaborative session attached as Exhibits DEH-1 through DEH-5 to my testimony, the Companies took reasonable steps to facilitate discussions with participants and to ensure that all topics participants asked to discuss were indeed discussed during the meetings.

Q. Did input from AMS Collaborative participants and other intervenors in the Companies' 2016 base-rate cases influence aspects of the Companies' proposal for full deployment of AMS?

A. Yes. There are three ways AMS Collaborative participants and other intervenors in the Companies' 2016 base-rate cases influenced the Companies' current proposal for full deployment of AMS.

First, the Companies originally proposed a system-wide deployment of AMS with no option for customers to opt out of AMS. The Companies are now proposing to permit customers to opt out of AMS service, as I discuss below. The Companies' decision to include an opt-out in this AMS-deployment proposal was influenced and shaped by feedback from AMS Collaborative participants.

Second, the Companies accounted for spare AMS meters and gas indices as a one-time, up-front purchase in their 2016 AMS deployment proposal. Based on input from the 2016 base-rate cases, the Companies have now accounted for purchases of spare meters and gas indices throughout the 2018-2040 service life of the proposed AMS project.

Third, the Companies' 2016 AMS proposal provided for a five-year recovery of the undepreciated book value of the meters to be removed and replaced by AMS meters, which effectively accelerated the recovery of the replaced meters' book value relative to their remaining service lives. Based on input the Companies received during their 2016 base-rate cases, the Companies are now proposing not to recover replaced meters' undepreciated book value on an accelerated schedule, but rather to recover it over the meters' remaining service lives. This approach effectively removes any impact of the replaced meters' undepreciated book value from the AMS cost-benefit analysis presented in the AMS Business Case (Exhibit JPM-1 to Mr. Malloy's testimony).

Therefore, participants in the AMS Collaborative and the Companies' 2016 base-rate cases had noticeable impacts on the Companies' full AMS deployment proposal in this proceeding.

AMS OPT-OUT

Q. Why are the Companies proposing an AMS opt-out in this proceeding when they did not do so when they first proposed full AMS deployment in 2016?

A. The Companies did not propose an opt-out from full AMS deployment in their 2016 proposal in view of the detrimental effect opt-outs can have on the benefits of a full deployment, as well as the Commission's opposition to opt-outs stated in the Commission's final order in Case No. 2012-00428: "Due to the potential negative impact on the operational benefits of a Smart Grid, the Commission does not support meter opt-outs, whether they be from digital, AMR or AMI meters."[5] The Companies agreed then and now that AMS functions best and provides the greatest benefits when all customers participate.

But the Commission also explained in Case No. 2012-00428 that although it did not support meter opt-outs due to the negative impacts, it understood the public concerns with smart meters and would consider opt-out proposals on a case-by case basis.[6] The Commission went on to state that "each utility can best determine the need for an opt-out provision" and it "will be at the utility's discretion" to determine whether an opt-out provision will apply to smart meters.[7] Moreover, the Commission recently considered and approved Duke Kentucky's Electric AMI Opt-Out Program Tariff ("Rider AMO"), confirming that properly designed opt-outs can be reasonable.[8]

[5] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 17 (Apr. 13, 2016).
[6] *Id.*
[7] *Id.*
[8] *In the Matter of: Application of Duke Energy Kentucky*, Case No. 2016-00152 (Ky. PSC May 25, 2017).

For the Companies, it became clear in their 2016 base-rate cases and again in the AMS Collaborative that some customers do indeed have a strong desire to be able to opt out of AMS.[9] Given that the purpose of AMS is to provide benefits to customers, if certain customers believe they would benefit from not having AMS deployed on their premises, the Companies will accommodate those desires as much as is reasonably possible.

But an important caveat to the opt-out the Companies are proposing to offer customers is that it must be subject to the Companies' existing authority to determine which metering is most appropriate to address operational or safety issues, e.g., meter access restrictions or safety hazards, including threats from customers. That authority is vital to ensuring the safety of the Companies' personnel and contractors, as well as to ensure the Companies' ability to regularly and reliably read meters. The Companies therefore do not propose to curtail or constrain their existing tariff authority to choose the metering appropriate for each customer; rather, they propose to give significant weight to a customer's opt-out request when making metering decisions.[10]

Q. Please briefly describe the Companies' opt-out proposal.

A. The Companies propose that, subject to the need for the Companies to continue to be able to address particular operational and safety concerns as I noted above, customers desiring to opt out of AMS be permitted to do so if their opting out does not shift

[9] Case No. 2016-00370, Direct Testimony of Paul Alvarez on Behalf of the Office of the Attorney General at 48 (Ky. Mar. 3, 2017); *see also* PSC Case No. 2016-00370, PSC Response to Emails at 1 (Ky. PSC Apr. 28, 2017); Case No. 2016-00370, Minutes of the Information Session and Public Meeting in Madisonville, Kentucky at 4 (Ky. PSC June 9, 2017).

[10] *See* Kentucky Utilities Company, P.S.C. No. 18, Original Sheet No. 98; Louisville Gas and Electric Company, P.S.C. Electric No. 11, Original Sheet No. 98; Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 98.

costs to other customers. To achieve that, the Companies are proposing a cost-based opt-out charge structure that will allow customers who desire to opt out to do so while keeping other customers whole with respect to costs opt-outs create. More specifically, the Companies propose an opt-out charge structure consisting of an opt-out set-up charge applied each time a customer opts out a meter and a recurring monthly opt-out charge applied per opted-out meter.[11] The proposed opt-out charges are shown in the table below:

Utility Service	Opt-Out Set-Up Charge	Recurring Monthly Opt-Out Charge
KU	$72.71	$32.45
LG&E electric	$57.86	$22.70
LG&E gas	$57.86	$21.80

Tariff sheets and cost support for the AMS Opt-Out Special Charges the Companies propose are attached to Mr. Lovekamp's testimony at Exhibits REL-1 (KU), REL-2 (LG&E electric), and REL-3 (LG&E gas).

The Companies' proposed cost-based approach is aligned with the Commission's position stated in Case No. 2012-00428: "[A]ny opt-out provision should require those customers that opt out to bear the cost related to that decision –

[11] The only exception to applying opt-out charges on a per-meter basis concerns the small number of situations in which the Companies currently bill multiple meters on a combined basis for operating convenience. *See* Kentucky Utilities Company, P.S.C. No. 18, Original Sheet No. 101.1; Louisville Gas and Electric Company, P.S.C. Electric No. 11, Original Sheet No. 101.1; Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 101.1. The Companies will apply only one opt-out set-up charge and one monthly charge in each such situation. For expediency and overall clarity, the Companies refer to the opt-out charge as a per-meter charge throughout their application and testimony in this proceeding.

through a one-time fee and/or a monthly charge, as appropriate."[12] This approach is also consistent with the opt-out charge structure of Duke Kentucky's Rider AMO, though the charges will likely differ to reflect the Companies' costs of opt-outs.

Q. Please explain the cost support for the AMS opt-out set-up charges and how the Companies propose to implement them.

A. The Companies' proposed opt-out set-up charges include estimated costs to: (1) create initial work orders for meter exchanges and optimize manual meter-reading routing; (2) travel to customers' premises, remove existing meters and replace with them with non-AMS meters, and close work orders; (3) take calls for opt-out customers, explain tariffs details, and set up account details for such customers; and (4) recover system set-up and license fees for systems needed for the non-communicating meter. The Companies calculated the opt-out set-up charges by dividing the total cost of these items by the number of customers expected to opt out (0.8% of each kind of utility customer, a percentage derived from industry experience with advanced-metering opt-outs).

Assuming the Commission issues a final order in this proceeding approving the AMS deployment as proposed, the Companies propose not to have the set-up charge apply to customers who request to opt out on or before the start of AMS meter deployment in their area. This proposal recognizes that customers' electing to opt out on or before the start of AMS meter deployment in their area might help the Companies avoid some of the costs the set-up charge is designed to collect by allowing the Companies to modify their deployment plans to some extent. But after

[12] Case No. 2012-00428, Order at 17 (Apr. 13, 2016).

deployment has started in that area, the Companies propose to have the set-up charge apply every time a customer requests to opt out one or more meters, irrespective of whether the customer has previously opted out other meters. This is appropriate because after deployment has started in that area, the Companies will not be able to avoid the costs the set-up charge is designed to recover.

Q. Please explain the cost support for the recurring monthly opt-out charges and how the Companies propose to implement them.

A. The Companies' proposed recurring monthly opt-out charges include numerous estimated costs shown in the cost support provided in Exhibits REL-1, REL-2, and REL-3. Among those are costs related to: (1) meter-reading and billing processes necessary to accommodate non-AMS meter readings; (2) non-AMS meter-reading equipment; (3) meter-reading labor and transportation; and (4) carrying an inventory of non-AMS meters. The Companies calculated the opt-out set-up charges by dividing the expected total cost of these items by the number of meters expected to be opted out (0.8%, again derived from industry experience with advanced-metering opt-outs).

The Companies propose not to have the recurring monthly charges apply within a particular deployment area until the deployment of AMS in that particular deployment area is complete and the Companies have validated that the meter-data-management and related systems are functioning properly to assure accurate and reliable remote meter reading (this validation process is called "AMI Certification"). After AMI Certification in a particular deployment area, the Companies propose to have the recurring monthly opt-out charges apply to each opted-out meter in that area, irrespective of whether the customer has other opted-out meters.

Q. When and how will customers be notified of their ability to opt out of AMS, and how will customers notify the Companies of their desire to opt out?

A. The Companies will include information concerning opt-outs in their customer-education efforts prior to AMS meter deployment. (Mr. Malloy addresses customer education in his testimony and in the AMS Business Case attached to his testimony as Exhibit JPM-1.) The Companies will begin providing this information to customers within a particular deployment area, along with other AMS educational messaging, prior to the beginning of AMS meter deployment within that area. This will give customers a reasonable opportunity to opt out on or before deployment has started in their area, affording such customers a reasonable opportunity to avoid opt-out set-up charges. The opt-out information provided to customers will include the amount approved for opt-out charges.

Q. What is your recommendation to the Commission?

A. It is my recommendation that the Commission approve the Companies' requests for full deployment of AMS. The AMS Collaborative, a thorough and comprehensive effort consuming about 40 hours over five days of meetings, assisted the Companies in understanding intervenor concerns and enabled participants to better understand the benefits of AMS. The influence of the AMS Collaborative participants is evident in the Companies' opt-out proposal. I therefore recommend the Commission grant the Companies' requested certificates of public convenience and necessity for full AMS deployment, approve the requested deviations from certain regulatory requirements as discussed in John P. Malloy's testimony, and approve the Companies' proposed AMS Opt-Out Special Charges.

Q. Does this conclude your testimony?

A. Yes.

400001.158429/1528610.1

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **David E. Huff**, being duly sworn, deposes and says that he is Director of Customer Energy Efficiency and Emerging Technology for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David E Huff

David E. Huff

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of January 2018.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

David E. Huff
Director, Customer Energy Efficiency and Emerging Technology
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202

Education

MBA, Indiana University
BSME, Rose-Hulman Institute of Technology

Professional Experience

Louisville Gas and Electric and Kentucky Utilities

Director, Customer Energy Efficiency and Emerging Technology	July 2017 - Present
Director, Customer Energy Efficiency and Smart Grid Strategy	March 2010 - July 2017
Director, Distribution Operations	March 2003 – March 2010

LG&E Energy

Director, Revenue Collection Process	January 2000 – March 2003

Louisville Gas and Electric

Director, Gas Operations Support & Interim Mktg Director	June 1997 – January 2000
Wholesale Excellence Team Leader	November 1995 – June 1997
Division Manager – Trimble County Station	July 1994 – November 1995
Operations Manager – Mill Creek Station	January 1992 – July 1994
Mechanical Engineer	1983 - 1992

Professional Memberships

Registered Professional Engineer – Kentucky
University of Louisville Conn Center for Renewable Energy Research -- Technical Advisory Board Member
E-Source DSM Executive Council Member

Civic Activities

Boy Scouts of America Executive Committee Member and Volunteer – Lincoln Heritage Council
Past Project WARM Board Member
Eagle Scout

AMS Collaborative
July 18 - Lexington

PPL companies

Safety Moment

EXITS and EVACUATION ROUTES

- Exits
  - Stairs near the elevator
  - Stairs through the break room

- If evacuation is required
  - Go to the parking lot across from the building, gather beside the 2 painted in the lot

- Restrooms
  - Across from the elevators

EXTREME HEAT

In the USA more people die in a typical year from excessive heat exposure than from hurricanes, lightning, tornados, floods and earthquakes combined

How to avoid being another victim:

1. Drink plenty of cool, non-alcoholic beverages
2. 16-32 oz (0.5 -1 liter) per hour when outside & active
3. Wear lightweight, light colored, loose-fitting clothing (and SPF 15+ sunscreen)
4. Use a buddy system and look out for each other

LG&E KU
PPL companies

AMS Collaborative

Agenda – Collaborative

Topic	Time	Host
Safety Moment	9:00 AM	David Huff
Welcome	9:10 AM	John Malloy
Introductions	9:45 AM	David Huff, Participants by group
Break	10:45 AM	
Kentucky Café	10:55 AM	Participants, Café Hosts
Lunch	11:55 AM	
Kentucky Café	12:30 PM	Participants, Café Hosts
Break	1:30 PM	
Kentucky Café Harvest	1:40 PM	Julie Gieseke
Next Steps	3:10 PM	David Huff
Session Close	3:30 PM	

How we got to here

11/23/16 — Application for CPCN

6/22/17 — Approval of Stipulation Agreement- including AMS Collaborative

6/26/17 — Collaborative Invitation

7/18/17 … — Collaborative Session 1

Introductions

One member to introduce your group and all participants from your group:

1. Organization Represented
2. Name(s)
3. What are your goals for this collaborative?
4. What do you want to get out of today?

AMS Collaborative Objectives

OVERALL

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests

TODAY

- Establish common objectives for the AMS Collaborative
- Identify all participant interests regarding AMS
- Determine ongoing engagement plan for the AMS Collaborative
- Actively engage participants in setting the agenda for subsequent meetings

What is a Kentucky Café?

KENTUCKY CAFÉ

- Real conversations about topics that matter
- Casual atmosphere to encourage openness
- Exchange of diverse ideas
- Openness to discuss other's perspective

Logistics for our Kentucky Café

INSTRUCTIONS

- **First 15 minutes**
  Discuss a given question in the group
- **Last 5 minutes**
  Use the remaining 5 minutes to document your discussions on post-its. 1 idea per post-it
- **At the clock**, add your post-its to the wall
- Cafe hosts available for assistance

LOGISTICS

- 4-5 people per table
- 4 Derby winners on your tag
- Per round, join the table that matches the Derby winner's name

BREAK

Kentucky World Café
Race 1

A. What are the interests of your constituency regarding AMS?

B. Now and in the future, what are the needs of your constituency regarding AMS?

Kentucky World Café
Race 2

A. What are the interests of your constituency regarding AMS?

B. Now and in the future, what are the needs of your constituency regarding AMS?

LUNCH

(Take time to walk the gallery)

Kentucky World Café
Race 3

Relative to AMS, what would your organization need to be able to support your constituency?

Kentucky World Café
Race 4

How can AMS benefit your constituency in the near and long term?

LG&E KU
PPL companies

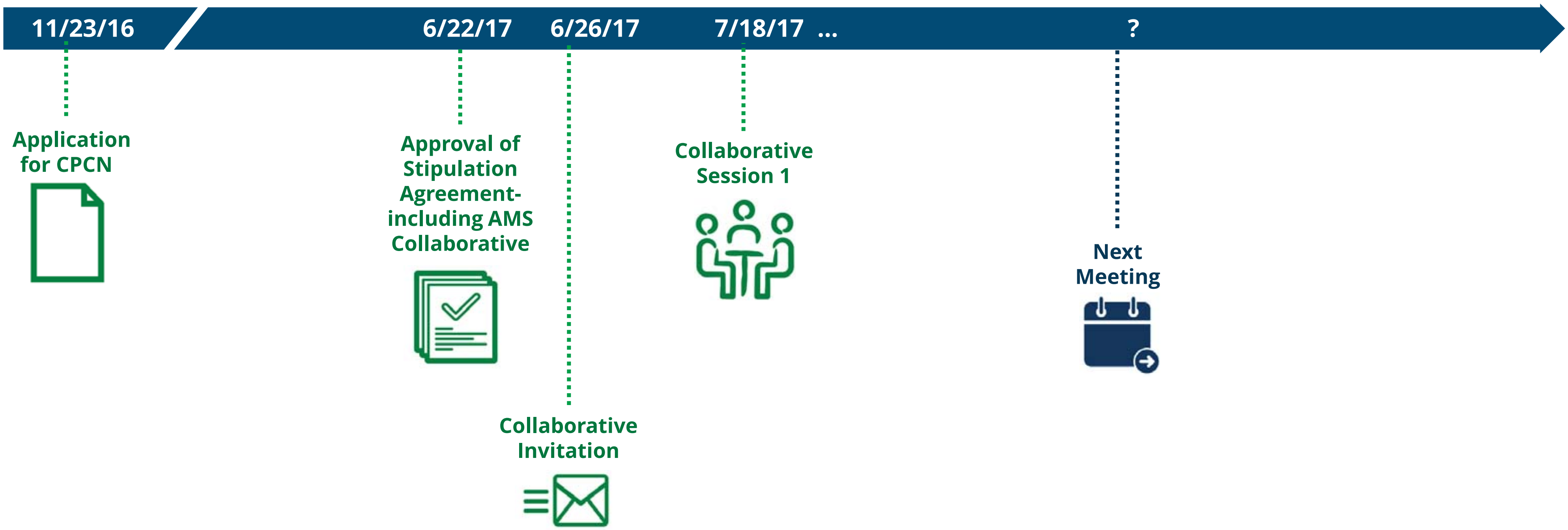
BREAK

(Take time to walk the gallery)

HARVEST

REFLECT

Moving Forward



THANK YOU

Overview of AMS Concerns

CONCERN	DETAILS
Remote Service Switch	• Increased volume of disconnections for non-payment • Automated disconnections may not account for steps being taken to resolve the situation, resulting in health or safety concerns, or lack of access to payment plans
Opt-Out	• Customers with health or privacy concerns should have the ability to opt out of the program, provided they cover the costs of meter replacement, meter reading, and other associated costs
New Services	• Availability of TOD or dynamic rate structures • Interest in TOD or dynamic rate structures • Demand billing • Pre-paid meter programs • Volt / VAR optimization
Business Case	• Regulatory asset establishment for the undepreciated value of early-retirement meters • ePortal benefits assumptions – overstated • Non-technical losses benefits assumptions – overstated • Meter replacement costs – understated. Replacements not accounted for within 21 year BC

AMS Collaborative
July 18 Session Summary

Exhibit DEH-1
Page 22 of 27
Huff

AMS Collaborative Session #1 – Logistics

Tuesday, July 18, 2017
9:00 AM – 3:30 PM ET
KU Office, One Quality, Lexington

Collaborative Objectives:
- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests

Session #1 Objectives:
- Establish common objectives for the AMS Collaborative
- Identify all participant interests regarding AMS
- Determine ongoing engagement plan for the AMS Collaborative
- Actively engage participants in setting the agenda for subsequent meetings

PARTICIPANTS

Participant	Organization
Mark Zoeller Cecil Goins Chris Seidt	Louisville Metro
Lisa Kilkelly Marlon Cummings*	Association of Community Ministries
Ron Willhite	KSBA
James Bush Richard Dugas	LFUCG
Rebecca Goodman Kent Chandler	OAG
Kurt Boehm*	KIUC
Tony Taylor	AT&T
Wallace McCullen*	Sierra Club
John Malloy* Allyson Sturgeon David Huff Wendy Wagoner Rick Lovekamp Cheryl Williams Lora Aria Meredith Needham	LG&E / KU
Jamie Hart Phyllis Goodson	Accenture
Julie Gieseke	Accenture / Map the Mind

*Not present for full session.

AGENDA

Topic	Time	Host
Safety Moment	9:00 AM	David Huff
Welcome	9:10 AM	John Malloy
Background & Objectives	9:20 AM	David Huff
Introductions	9:30 AM	Participants by group
Kentucky Café	10:55 AM	Participants, Café Hosts
Break	10:45 AM	
Kentucky Café	11:00 AM	Participants, Café Hosts
Lunch & Gallery Walk	12:00 PM	
Kentucky Café Harvest	1:00 PM	Café Hosts, Julie Gieseke
Break	2:15 PM	
Key Theme Sequencing	2:30 PM	Café Hosts
Next Steps	2:50PM	David Huff
Session Close	3:15 PM	

LG&E KU PPL companies

AMS Collaborative
Session #1 – Kentucky Café Discussions

Description:
- Real conversations about topics that matter
- Casual atmosphere to encourage openness
- Exchange of diverse ideas
- Openness to discuss other's perspective

Approach:
- First 15 minutes - Discuss a given question in the group
- Last 5 minutes - Use the remaining 5 minutes to document your discussions on post-its. (1 per)
- Add post-its to the wall

Logistics:
- 3-4 people per table
- 4 total rounds
- Café hosts available for assistance

Question 1:
What are the interests of your constituency regarding AMS?

Question 2:
Now and in the future, what are the needs of your constituency regarding AMS?

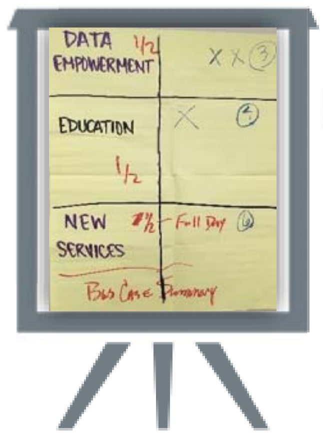
Question 3:
Relative to AMS, what would your organization need to be able to support your constituency?

Question 4:
How can AMS benefit your constituency in the near and long term?

AMS Collaborative
Session #1 – Key Themes & Sequencing

Description:
- Identify key themes / topic areas to address through subsequent collaborative sessions
- Participants determine sequence in which to address topics

Approach:
- Kentucky Café discussions post-its were grouped into clusters of similar topics
- Facilitators led full-group debrief to confirm clusters / re-aligned as needed
- Participants ratified Key Themes proposed by facilitators
- Non-LKE participants voted to sequence themes
- Facilitators led group through tie-breaker discussions to finalize sequence & estimate duration needed to address



Participant Voting Charts

Order	Theme	Summary Description	Estimated Duration
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	½ Day
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	½ Day
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	½ Day
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	½ Day
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	½ Day
7	**Cost / Benefit Recap**	• Review of business case with adjustments	½ Day

AMS Collaborative Session #1 Next Steps

FUTURE MEETINGS

Collaborative participants agreed to:

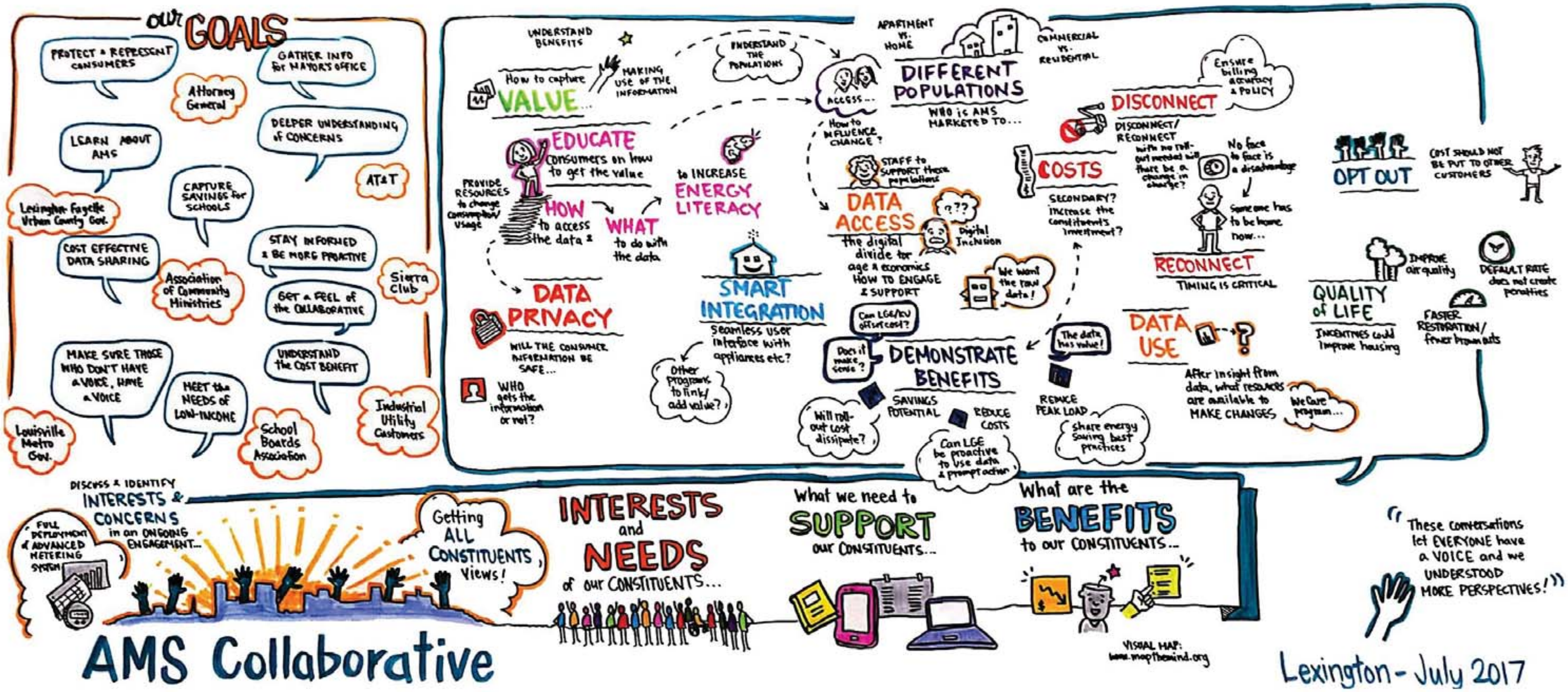
- Establish monthly cadence
- Schedule out next 4 months
- Sequence of topics based on voting and tie-breaker discussions
- Host future sessions in Frankfort – LKE investigating options

TENTATIVE SCHEDULE*

AUG	SEP	OCT	NOV	…
Costs / Benefits - Baseline	Data Privacy / Sharing & Data Empowerment	Education & Remote Disconnect / Reconnect	New Services & Cost / Benefit - Recap	

*Specific dates to be determined; topics may shift to earlier month if agenda allows.

AMS Collaborative
Session #1 Visual Map



AMS Collaborative
Session 2 Approach

Safety Moment

EXITS and EVACUATION ROUTES

- Exits
  - Exits are at the opposite far ends of the hallway

- If evacuation is required
  - Go to the parking lot across from the building, gather in the far right corner

- Restrooms

HAZARDS

A hazard is a condition or circumstance that could lead to an unplanned or undesired event. Physical examples can include uneven walkways, roads, pinch points, blind spots, and poor lighting.

How to deal with hazards:

1. Be aware of your surroundings
2. Use peripheral vision
3. Ensure that effective hazard controls are in place, i.e. engineering controls, administrative controls, protective equipment

Awareness is key!

Agenda – Collaborative

Tuesday, August 22, 2017
9:00 AM – 3:30 PM ET
Noah's

Collaborative Objectives:
- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests and questions

Session #2 Objectives:
- Review cost / benefit baseline provided in business case
- Present the business case methodology
- Encourage discussion and questions to clarify information
- Understand business case areas that are important to your constituents

Topic	Time	Host
Safety Moment, Agenda, Session 1 Review, and Introductions	9:00 AM	Phyllis Goodson
AMS Introduction	9:30 AM	David Huff
Break	10:15 AM	
Costs	10:30 AM	Jonathan Whitehouse, Sam Stickler
Small and large group discussion	11:10 AM	Participants, Jonathan Whitehouse, Sam Stickler
Lunch	11:30 AM	
Benefits and small group discussions	12:00 PM	Jonathan Whitehouse, Sam Stickler, Participants
Benefits large group discussion	1:45 PM	Participants, Jonathan Whitehouse, Sam Stickler
Break	2:15 PM	
Business case questions and debrief	2:30 PM	Phyllis Goodson, Jamie Hart
Summary and next steps	3:00 PM	David Huff

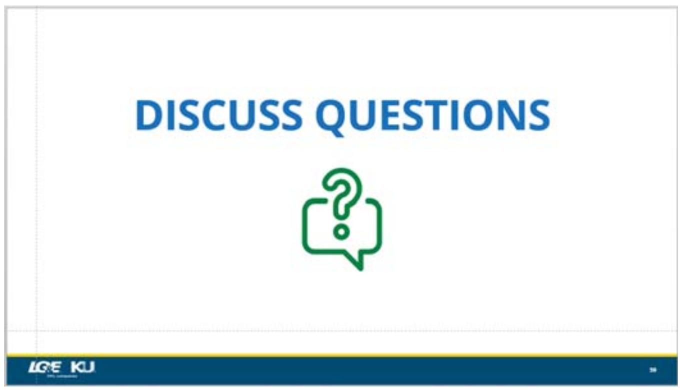
Group Discussions

Small Groups

- Electric Meter
- Gas Index
- Router
- Collector
- MyMeter

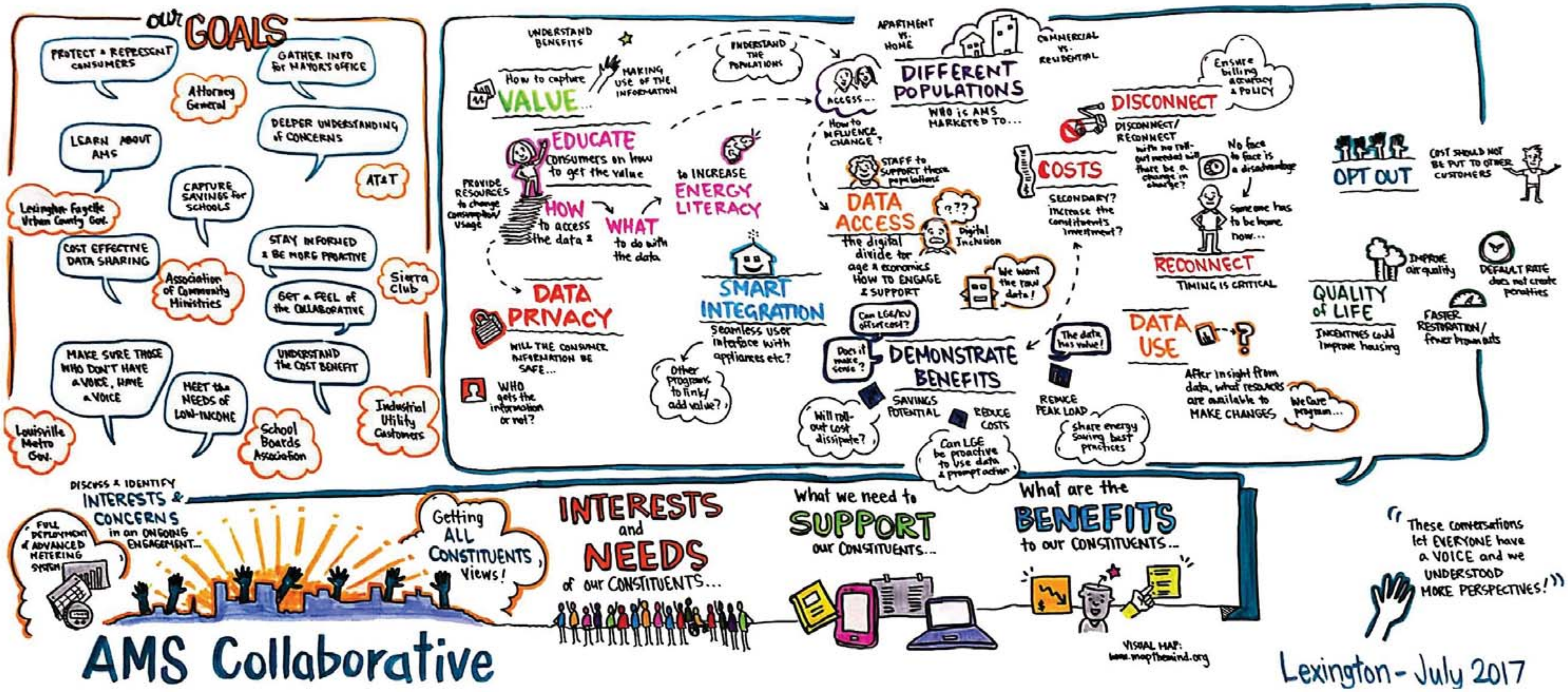
Large Group

- Review questions from the smaller groups

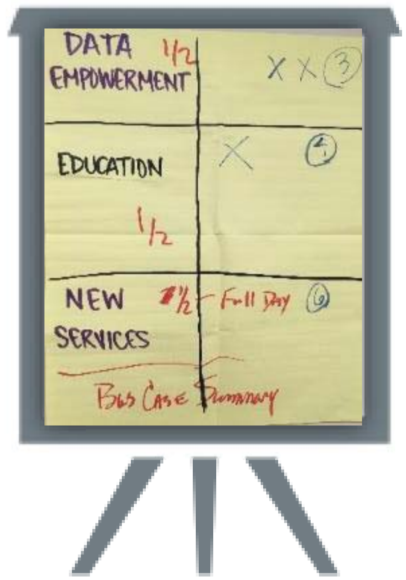


AMS Collaborative
Session 1

AMS Collaborative
Session #1 Visual Map



AMS Collaborative
Session #1 – Key Themes & Sequencing



Participant Voting Charts

Order	Theme	Summary Description	Estimated Duration
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	½ Day
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	½ Day
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	½ Day
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	½ Day
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	½ Day
7	**Cost / Benefit Recap**	• Review of business case with adjustments	½ Day

AMS Collaborative
Session #1 – Key Themes & Sequencing

Order	Theme	Summary Description	Estimated Duration
✓ 1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	½ Day
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	½ Day
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	½ Day
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	½ Day
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	½ Day
7	**Cost / Benefit Recap**	• Review of business case with adjustments	½ Day

SCHEDULE

AUG 22	SEP 20	OCT 17	NOV 8 …
Costs / Benefits - Baseline	Data Privacy / Sharing & Data Empowerment	Education, Opt-out, & Remote Disconnect / Reconnect	New Services & Cost / Benefit - Recap

AMS Collaborative Future Sessions

Order	Theme	Summary Description	Estimated Duration
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	½ Day
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	½ Day
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	½ Day
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	½ Day
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	½ Day
7	**Cost / Benefit Recap**	• Review of business case with adjustments	½ Day

SCHEDULE

AUG 22 — Costs / Benefits - Baseline

SEP 20 — Data Privacy / Sharing & Data Empowerment & Education

OCT 17 — ~~Education,~~ Opt-out, & Remote Disconnect / Reconnect & New Services

NOV 8 — ~~New Services~~ & Cost / Benefit - Recap

…

PPL companies

AMS Collaborative Session 2

AMS Collaborative Objectives

OVERALL

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests

TODAY

- Review cost / benefit baseline provided in business case
- Educate participants on business case methodology
- Encourage discussion and questions to clarify information
- Understand business case areas that are important to your constituents

LG&E KU
PPL companies

Introductions

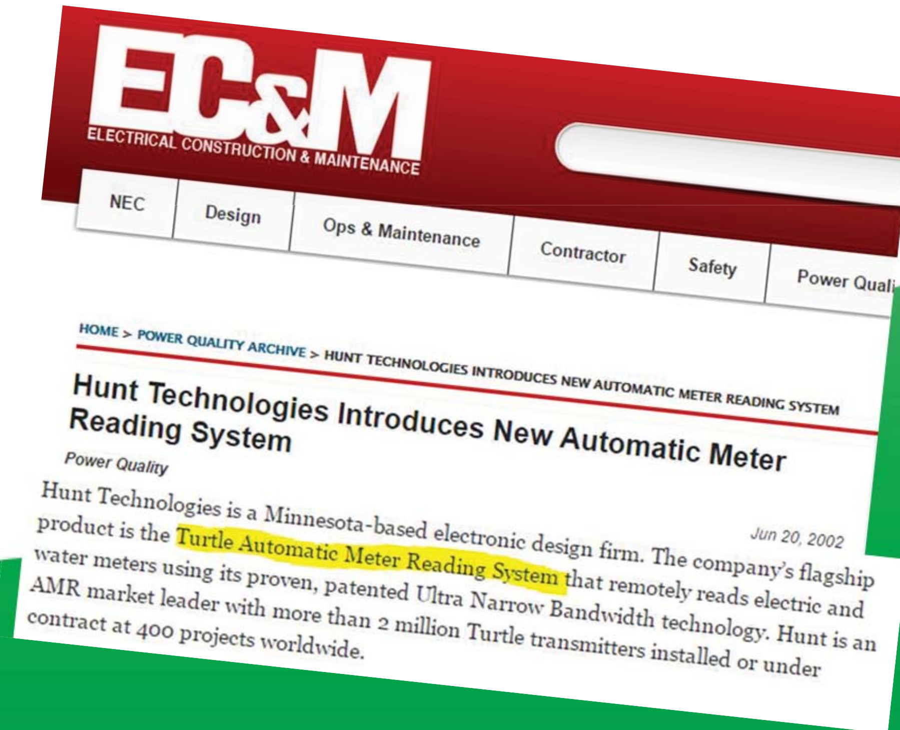
One member to introduce your group and all participants from your group:

1. Organization Represented
2. Name(s)
3. What was the feedback from your constituency on Session 1?
4. What are your goals today specific to the business case discussions?

AMS INTRODUCTION

Meters with automated reading capabilities

- In 1999, KU began with AMR with **4,000 Turtle meters** in Wilmore, Kentucky. Turtle meters transmitted meter reads over PLC (power line carrier) .
- System has performed **reliably**.


EC&M
ELECTRICAL CONSTRUCTION & MAINTENANCE

NEC | Design | Ops & Maintenance | Contractor | Safety | Power Quali

HOME > POWER QUALITY ARCHIVE > HUNT TECHNOLOGIES INTRODUCES NEW AUTOMATIC METER READING SYSTEM

Hunt Technologies Introduces New Automatic Meter Reading System

Power Quality

Jun 20, 2002

Hunt Technologies is a Minnesota-based electronic design firm. The company's flagship product is the Turtle Automatic Meter Reading System that remotely reads electric and water meters using its proven, patented Ultra Narrow Bandwidth technology. Hunt is an AMR market leader with more than 2 million Turtle transmitters installed or under contract at 400 projects worldwide.

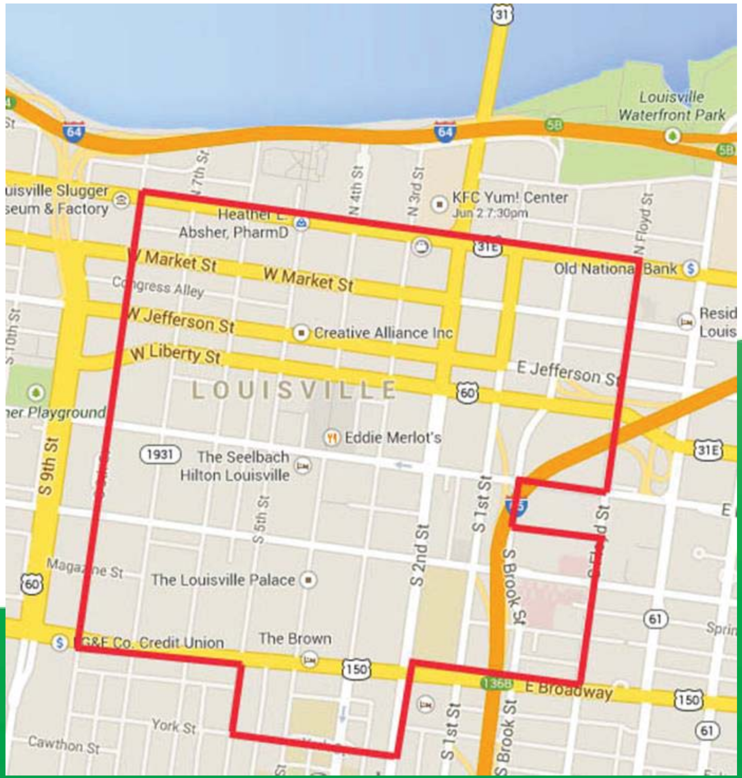
Turtle Meters
1999 – today

Initial Customer “Responsive Pricing Pilot” Research Findings

- Customers derive the most value from the feeling of “**<u>control</u>**” that the program creates.
- Regardless of actual behaviors and tangible cost savings, respondents felt a greater sense of “**<u>empowerment</u>**” as a direct result of the program.
- While individual behaviors differed, the equipment and the information provided customers with the **<u>data they needed to make more informed decisions.</u>**
- Customers did not always make the most “energy efficient” decisions, but they still **<u>felt positive in knowing that it was their decision to make.</u>**

Downtown Network

- In 2014, approximately 1,500 advanced meters were deployed in the downtown Louisville area to support **<u>distribution network operations and analytical needs</u>**.
- Monitoring included load, voltage, and engineering-specific data to improve modeling, analysis, and **<u>overall management of the network</u>**.
- Downtown network supports enhanced capacity planning; enables accurate modeling of normal, peak, and contingency conditions; and **<u>mitigates the possibility of a significant outage event</u>** in the core downtown Louisville area.



Turtle Meters
1999 – today

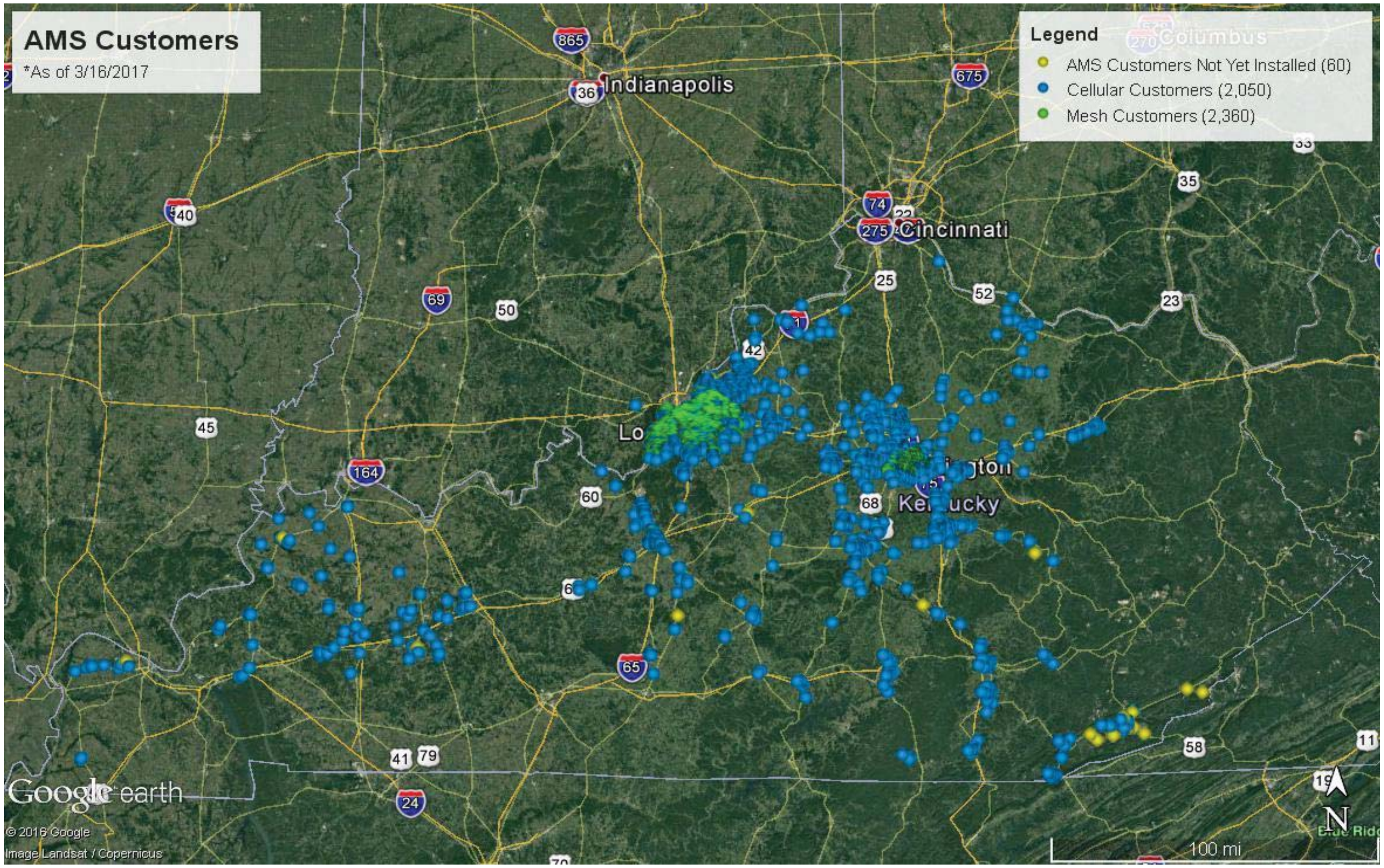
Responsive Pricing Pilot
2008 – 2010

Downtown Network
2014 - today

Rollout of Advanced Meter Opt-in Program

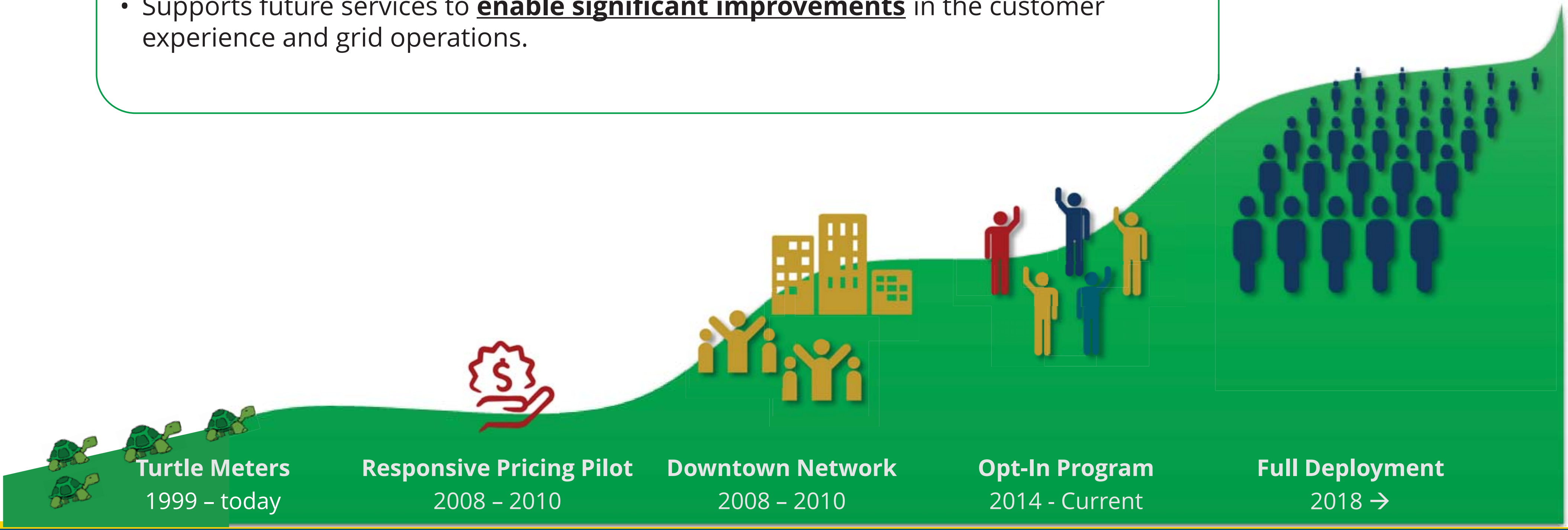
- Our new Advanced Meter Service puts **the power to control personal energy use in your hands.**
- **Available all across the state**, not just urban areas.
- You can use your MyMeter dashboard to:
  - Track daily, weekly, monthly or yearly energy usage.
  - **Compare your energy use** from season to season, or before, during, and after efficiency improvements.
  - **Set energy-saving reminders** for things like changing furnace air filters or light bulbs.
  - **Customize your dashboard profile** with relevant information about your home or business –building size, the type of appliances you have, improvements that could make a difference in your energy use, etc.

Advanced Meter Opt-In Pilot



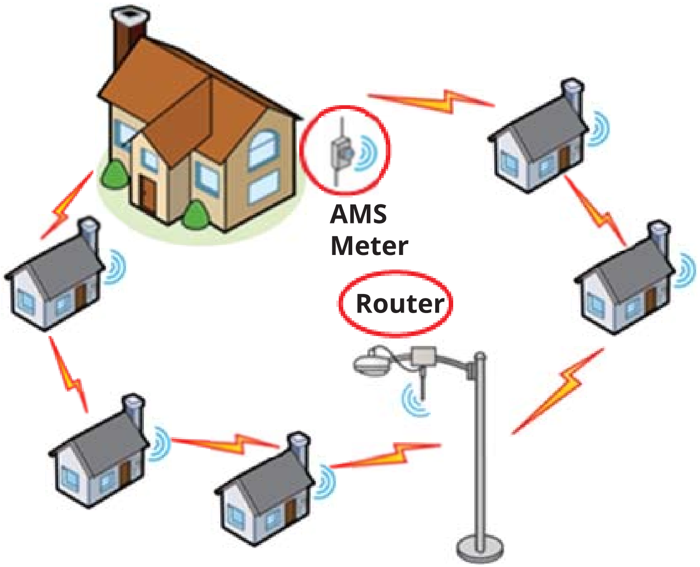
Full Deployment

- To achieve full benefits, full deployment is necessary across LG&E and KU territories.
- Supports future services to **<u>enable significant improvements</u>** in the customer experience and grid operations.

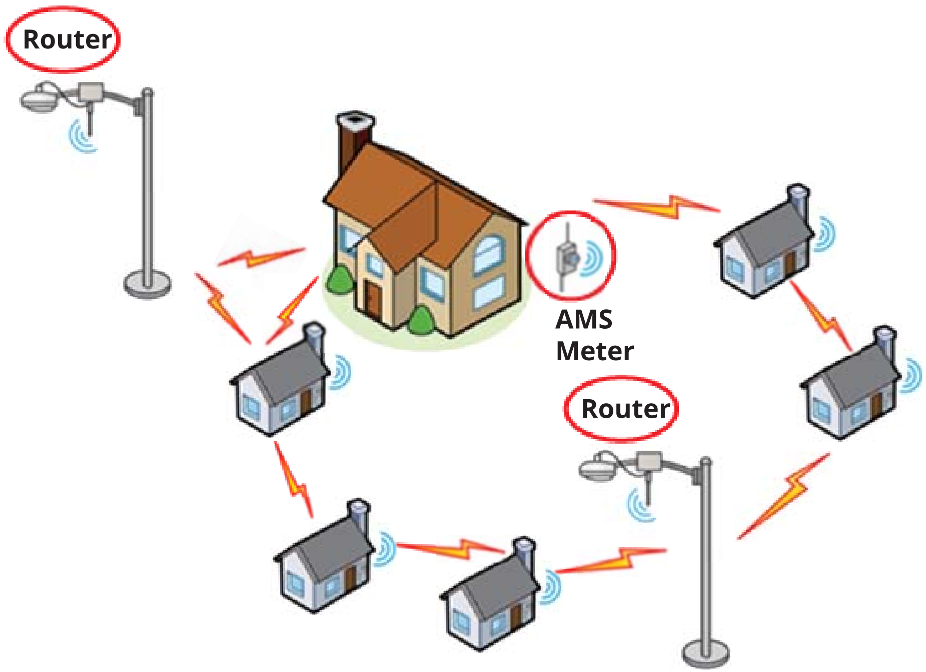


DEMO LINK to mymeter

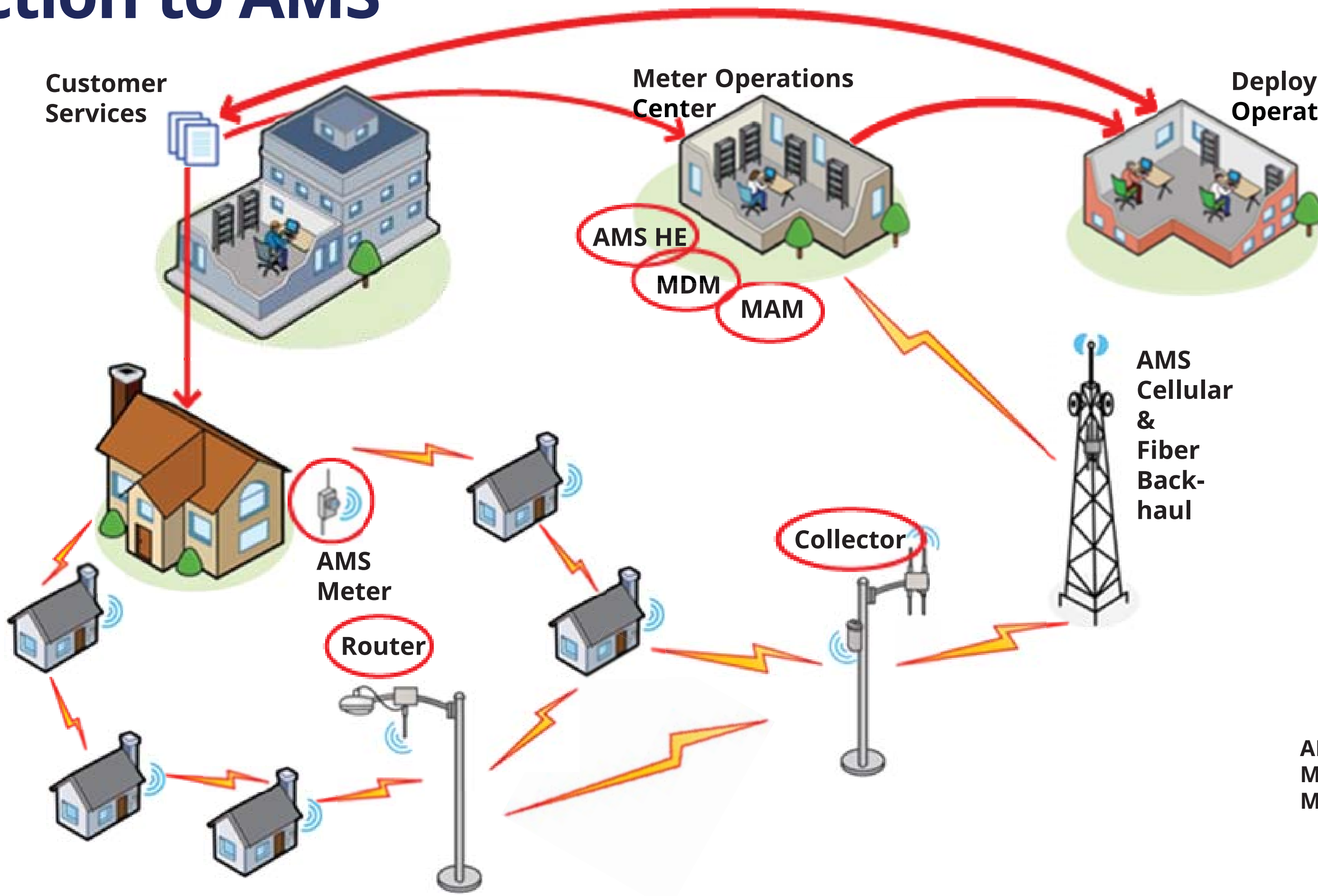
Introduction to AMS



Introduction to AMS



Introduction to AMS



AMS HE – AMS Head End
MDM – Meter Data Management
MAM – Meter Asset Management

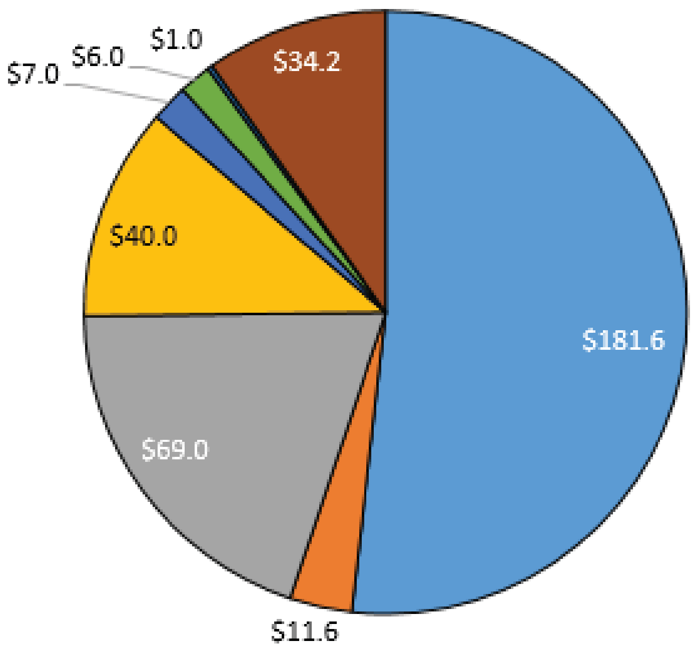
Business case

- Mechanics and methodology
  - What is the process, where do we get figures and estimates
    - Company considered technology since 2009 (evaluating $, technology and risk)
    - Many costs associated with business case are derived from the most current information available including RFP responses, dollars associated with parent company business case, industry best practices and industry lessons learned
    - Financial information is reflected across two different time frames
      - The business plan – 5 years
      - Expected Project Life
- Assumptions
  - No opt-outs, 100% coverage for applicable customers
  - 2 Waivers
    - 807 KAR 5:006, Section 7(5)
    - 807 KAR 5:006, Section 14(3)

BREAK

BUSINESS CASE COSTS

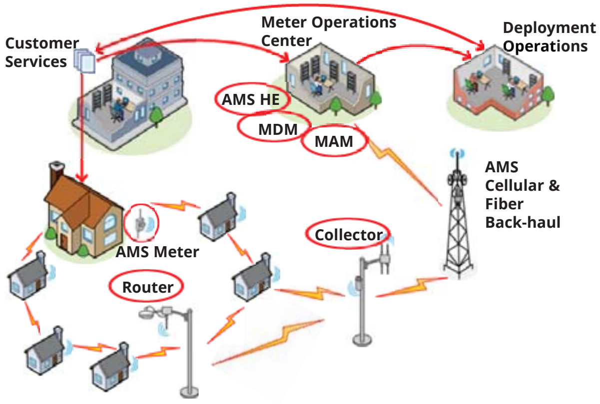
Gross AMS implementation costs are ~$350 Million for 2016 – 2021

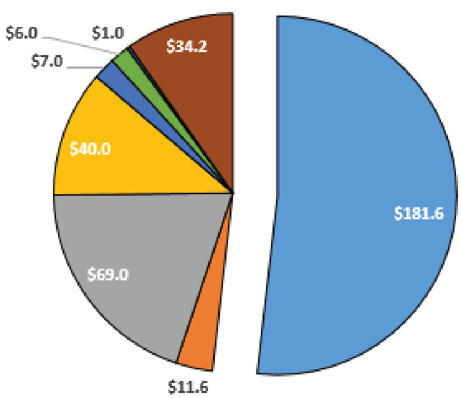


Project Costs 2016 – 2021 $ Millions

Category	Capex	OpEx	Total
Meters	167.0	14.6	**181.6**
Network & Network Management	10.4	1.2	**11.6**
Information Technology	56.7	12.3	**69.0**
Systems Integration	40.0	-	**40.0**
Program Management	5.1	1.9	**7.0**
Communications	6.0	-	**6.0**
Change Management	1.0	-	**1.0**
Contingency	34.2	-	**34.2**
Total	**320.4**	**30.0**	**350.4**

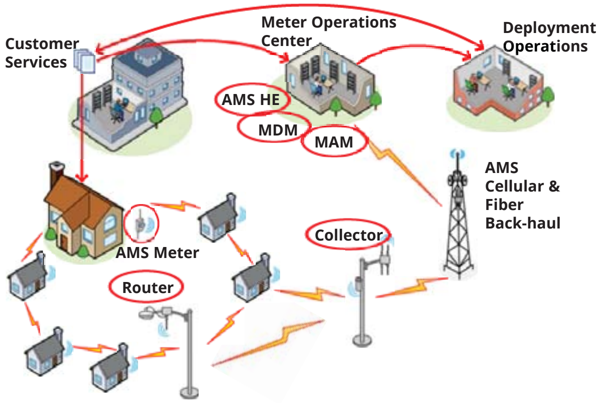
Metering

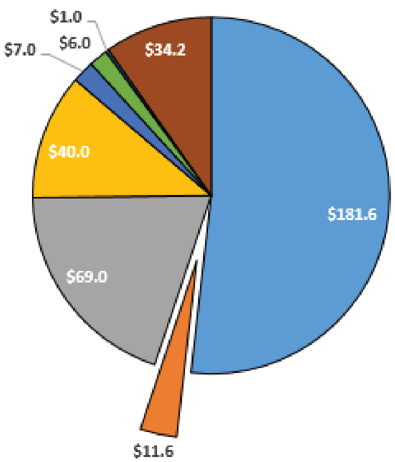




Category	Description	Total Costs
Metering	Capital 1) 980,000 electric meters and 322,000 gas meter indices 2) Installation costs • Average per electric meter – $23.56 • Average per gas index cost – $9.00 3) Spare inventory, new meter testing, etc. O&M 1) Meter base repairs 2) Testing	Capital 1) Meter and indices cost $125.9 M 2) Installation costs $32.6 M 3) Spare inventory, new meter testing, etc. $8.5 M $167 M O&M 1) Meter base repair $8.9 M 2) Testing $5.7 M $14.6 M • **$181.6 Million**

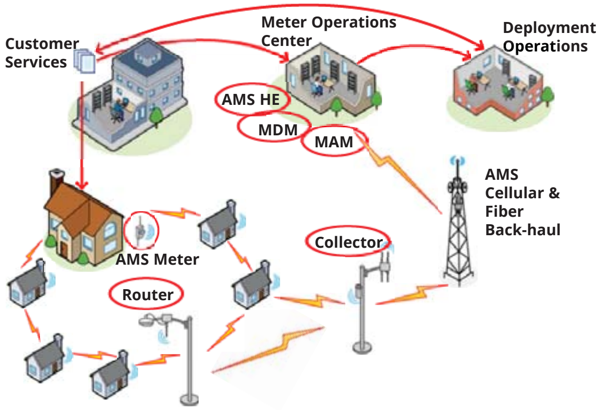
Network and Network Maintenance

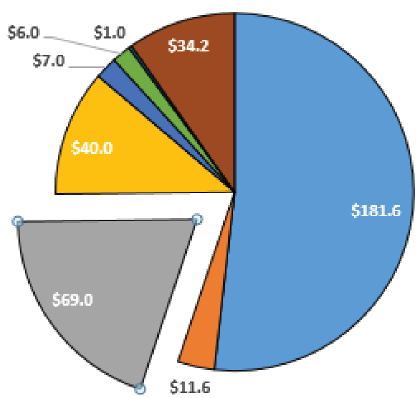




Category	Description	Total Costs
Network and Network Maintenance	Capital 1) 2,200 Routers and 150 Collectors 2) Installation costs, planning and engineering, training, and testing 3) Backhaul and miscellaneous equipment, and component replacement O&M 1) Ongoing labor and maintenance to support network infrastructure	Capital 1) Collector and Routers $4.8M 2) Installation costs $4.9M 3) Additional equipment <u>$0.7 M</u> $10.4 M O&M 1) Ongoing labor and maint. $1.2 M • **$11.6 Million**

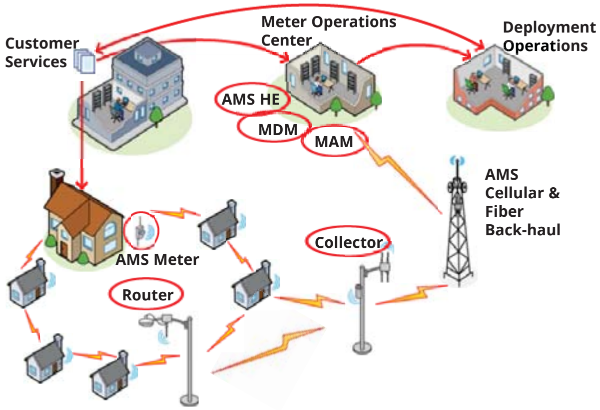
Information Technology

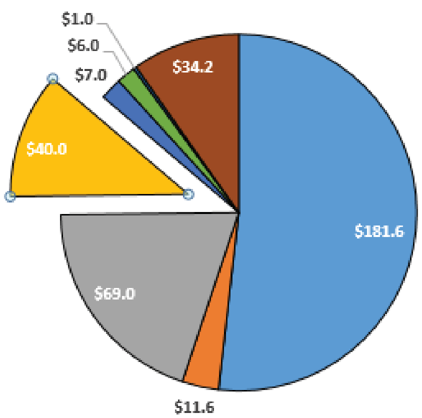




Category	Description	Total Costs
Information Technology	Capital 1) Software (head-end, MDM, portal, meter operations center, meter asset management), hardware, licensing, IT developmental labor O&M 1) Maintenance, vendor support, ongoing internal IT resources costs	Capital 1) Software, hardware, licensing $56.7 M O&M 1) Costs $12.3 M • **$69 Million**

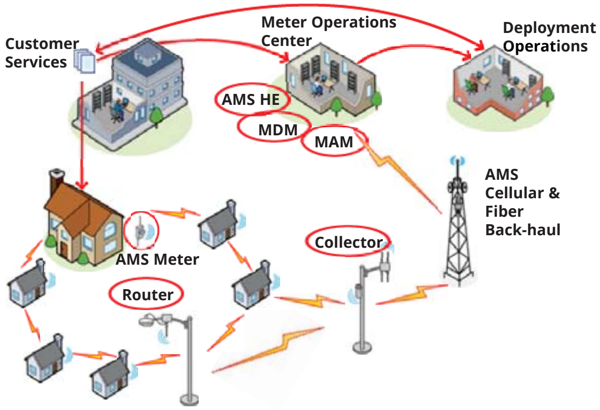
System Integration

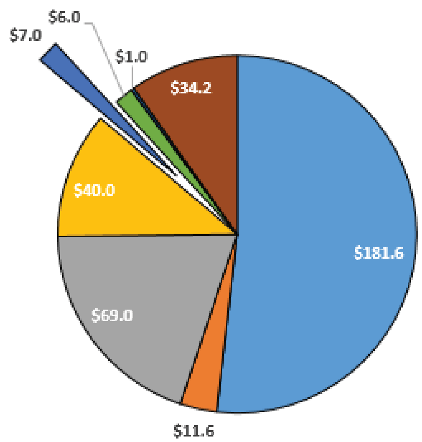




Category	Description	Total Costs
System Integration	Capital 1) Coordinating and managing the implementation of different IT packages: overall architectural guidance, platform design, supporting security requirements, integration across disparate systems, comprehensive test plan development, and execution O&M 1) none	Capital 1) System Integration costs $40 M O&M 1) none • **$40 Million**

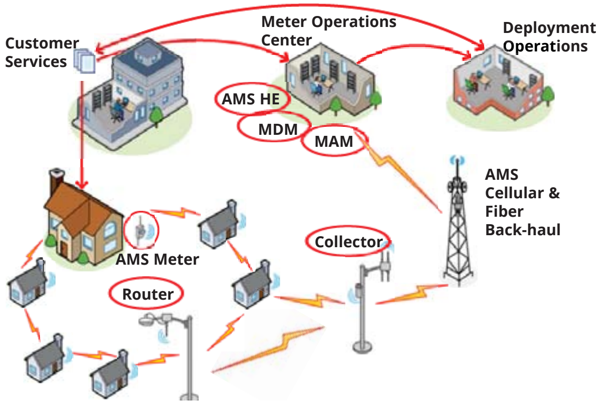
Program Management

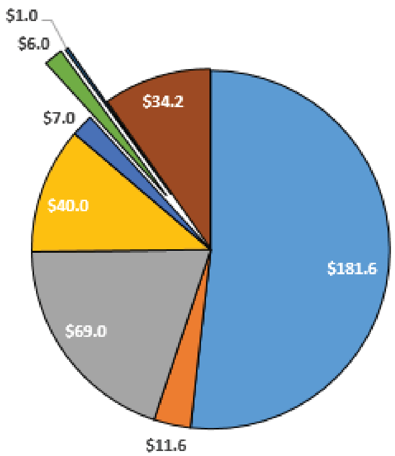




Category	Description	Total Costs
Program Management	Capital 1) Program management through 2020 including program leadership, project management, business process development, and redesign O&M 1) Ongoing Program support for 2020-2021	Capital 1) Program management $5.1 M O&M 1) Program support costs $1.9 M • **$7 Million**

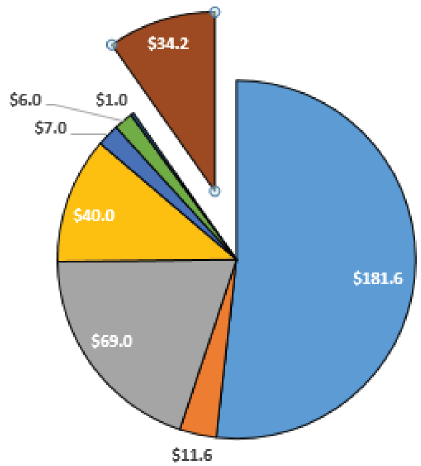
Customer Communication & Change Management





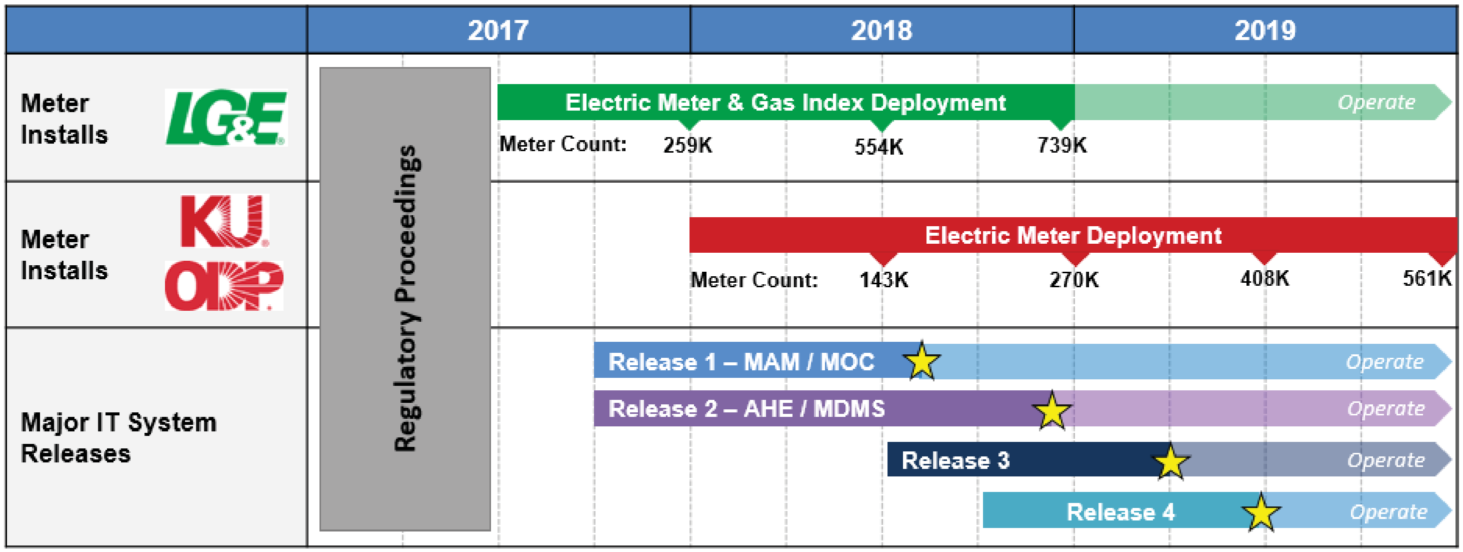
Category	Description	Total Costs
Customer Communications and Change Management	Capital 1) Training costs including development of training modules with guides and training delivery 2) Customer education includes development of AMS plan-related materials for all stakeholders and delivery of relevant education and messages through appropriate channels and within designated timeframes O&M 1) none	Capital 1) Training costs $1.0 M 2) Customer education costs $6.0 M O&M 1) none • **$7.0 Million**

Contingency



Category	Description	Total Costs
Contingency	Capital 1) 12% of total capital costs O&M 1) none	Capital 1) Contingency costs $34.2 M O&M 1) none • **$34.2 Million**

Proposed Project Lifecycle



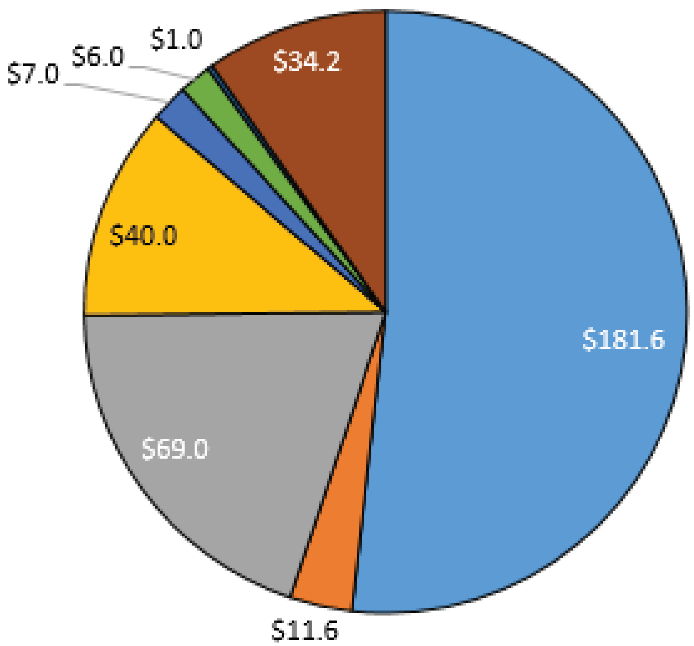
Release 1
- Install MAM
- New meter scanners
- Setup MOC

Release 2
- Back-office Network Setup
- Install AMS Head Ends
- Install MDMS
- Daily Validation of RF Usage Data (VEE)

Release 3
- Third Party Data Presentment
- Meter Ping (Basic Outage Use Cases)

Release 4
- Remote Connect / Disconnect
- Interval Billing

Gross AMS implementation costs are ~$350 Million for 2016 – 2021



Project Costs 2016 – 2021 $ Millions

Category	Capex	OpEx	Total
Meters	167.0	14.6	**181.6**
Network & Network Management	10.4	1.2	**11.6**
Information Technology	56.7	12.3	**69.0**
Systems Integration	40.0	-	**40.0**
Program Management	5.1	1.9	**7.0**
Communications	6.0	-	**6.0**
Change Management	1.0	-	**1.0**
Contingency	34.2	-	**34.2**
Total	**320.4**	**30.0**	**350.4**

LG&E KU PPL companies

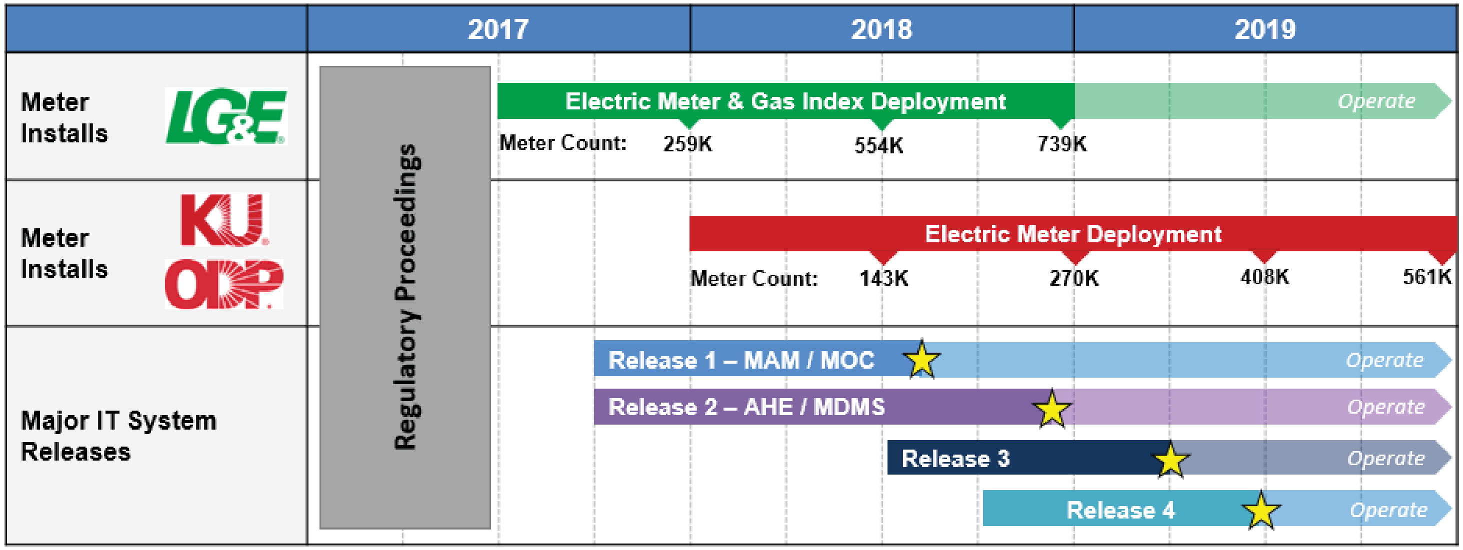
DISCUSS IN GROUPS

DISCUSS QUESTIONS

LUNCH

BUSINESS CASE BENEFITS

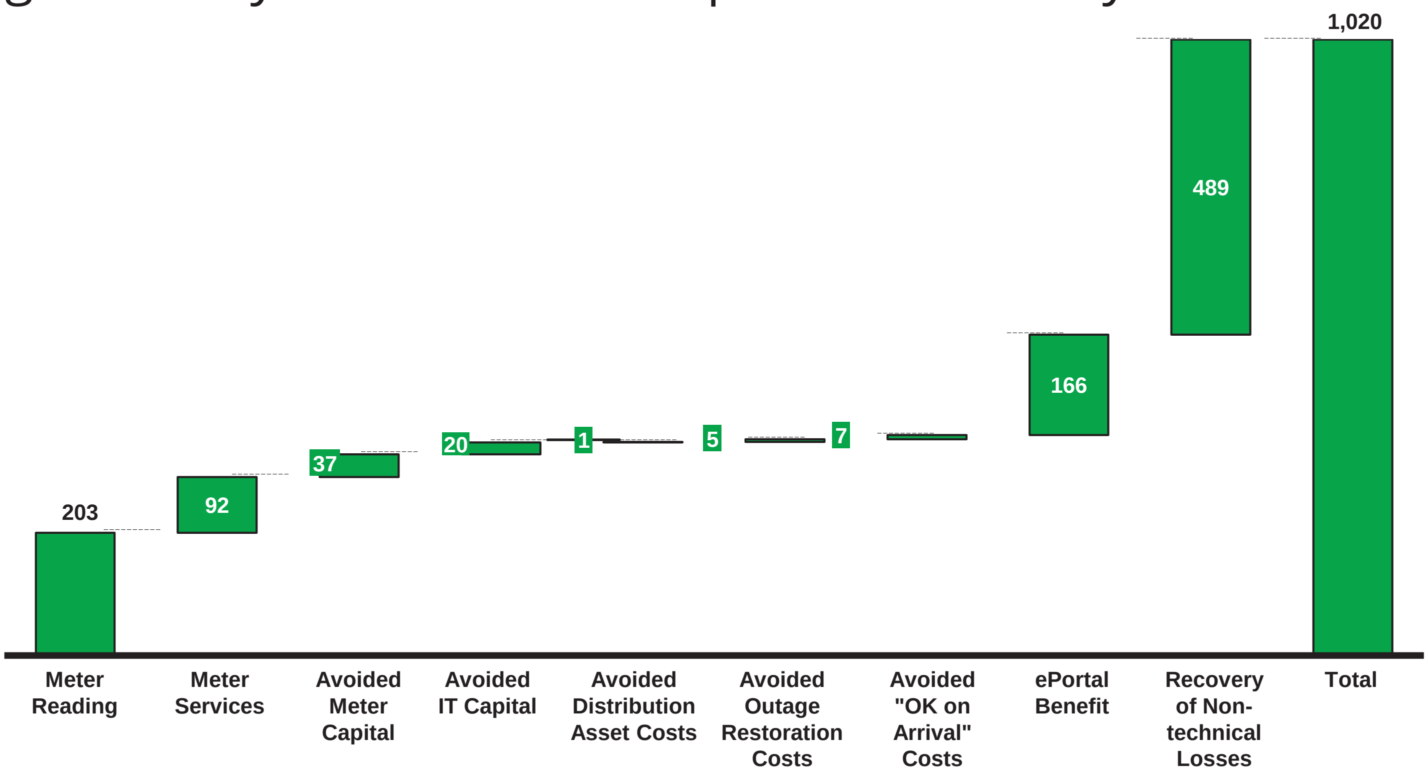
Proposed Project Lifecycle



Release 1	Release 2	Release 3	Release 4
▪ Install MAM ▪ New meter scanners ▪ Setup MOC	▪ Back-office Network Setup ▪ Install AMS Head Ends ▪ Install MDMS ▪ Daily Validation of RF Usage Data (VEE)	▪ Third Party Data Presentment ▪ Meter Ping (Basic Outage Use Cases)	▪ Remote Connect / Disconnect ▪ Interval Billing

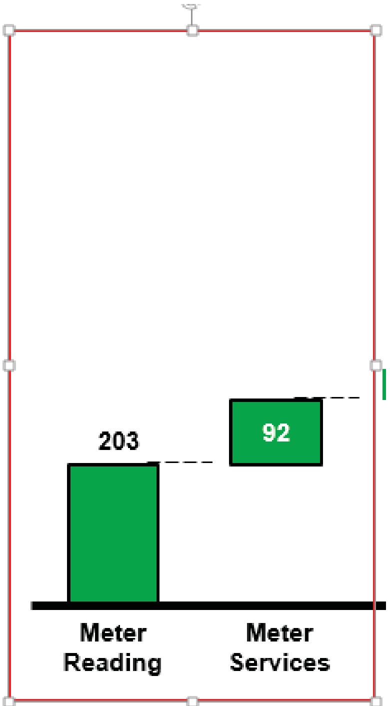
AMS Benefits Summary

- Total savings of nearly $1020 Million are possible over 20 years



Reference: Page 67, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 _10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Meter Reading and Meter Services



Category	Description	Total Savings[1]

Meter Reading	• Total number of AMS meters * yearly contract value per meter * escalation factor * number of recovery years once MDMS is implemented – the annual cost of the inspectors
	• Levers
	  • Contractors perform meter reads monthly in the LG&E territory at $0.42/read, and in the KU and ODP territories at $0.70/read.
	  • Assumed a cost escalation factor of 2.2%
	  • Assumed no inspection variance is allowed and 14 PSC inspector are included
		AMS 20 yr. savings **$203 Million**

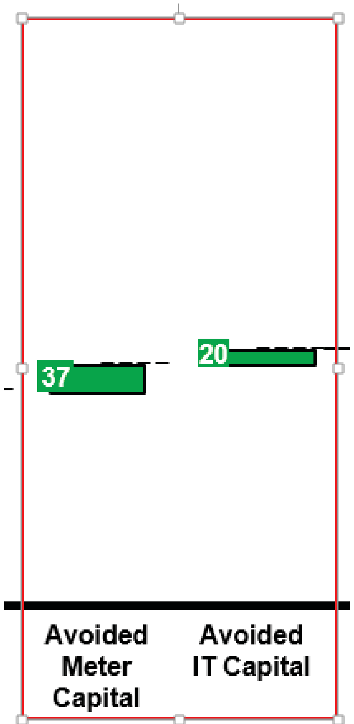
• Meter Services	• Utilizing the five-year budget define contractor spend, employee OT spend and material spend by year.
	• For the five-year projection used the defined cuts to project savings.
	• Take the 5th year budget savings and project it out with an escalation factor to the end of the recovery period.
	• Levers
	  • Reduced Employee OT at LG&E by 50% starting in 2019
	  • Reduced Employee OT at KU by 33% in 2019 and by 50% starting in 2020
	  • Contractor budget for LG&E will be reduced to 4 techs starting in 2019
	  • Contractor Budget for KU will be reduced to 17 techs in 2019 and 7 techs starting in 2020
	  • Reduced Purchased Materials by: '18: 0%, '19: 10%, '20: 20%, '21: 20%.
		The meter services technician force is reduced due to AMS digitalizing the process along with the need for OT
		AMS 20 yr. savings **$92 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 188, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

DISCUSS IN GROUPS

DISCUSS QUESTIONS

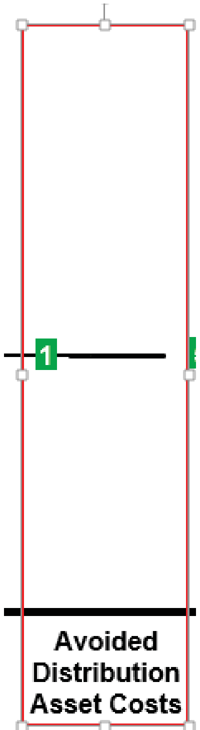
Avoided / Deferred Capital



Category	Levers / Calculations Assumptions	Total Savings[1]
Avoided IT Capital	• Based on the AMS implementation timeline, staffing levels, projected budgets, company priorities, and eliminating programs associated with manual meter reading, along with other factors, IT spend categories were evaluated.	AMS 20 yr. savings **$20 Million**
Avoided Meter Capital	• The AMS implementation timeline, projected budgets, company priorities, inventory levels and the different types of meters to be deployed as a part of the AMS program were evaluated to build the savings projections.	AMS 20 yr. savings **$ 37 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 189, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to Spanos_-_FINAL.pdf.

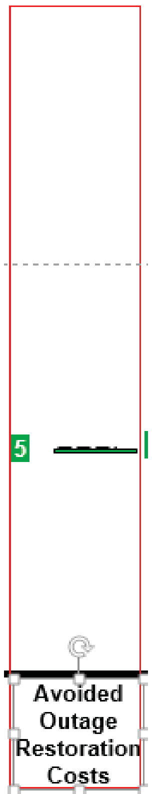
Avoided Distribution Asset Costs



Category	Calculations Assumptions	Total Savings[1]
Avoided Distribution Asset Costs	1) Savings of 45 min. per outage for planned replacements • Transformer failures = 6,000 • Number of transformer failures avoided = 250 • Average crew size = 2 • Average hourly loaded cost for crew = $65 pp 2) Protected revenue from reduced restoration time • # of customers in trans-former outages = 5 • Annual avg. energy consumption = 30 MWh • Average retail price = 0.10 $/kWh • Assumes 4% average electric retail escalation	1) 250 outages x 45 min. time reduction / 60 x 2 x 65 / hr. field labor * labor escalation • **$764 Thousand** 2) 250 outages x 5 customers x 2.57 kWh usage x 0.10 $/kWh * retail escalation • **$11.2 Thousand** AMS 20 yr. savings **$0.8 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 190, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

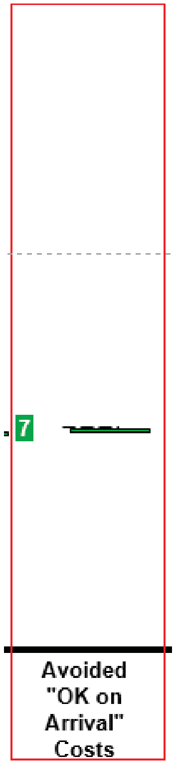
Avoided Outage Restoration Costs



Category	Calculations Assumptions	Total Savings[1]
Outage Management Costs	1) Reduction in time spent identifying outage location • Outage duration (CAIDI) – Blue Sky = 96 mins. • Reduction in time spent = 9.6 mins. • # of Blue Sky outages = 20,000 • % non-DA circuits = 50% • Average crew size = 1 • Average hourly loaded cost for crew = $65 pp • Assumes 3% labor escalation 2) Protected revenue from reduced restoration time • # of customers in Blue Sky outages = 40 • Annual avg. energy consumption = 30 MWh • Average retail price = 0.10 $/kWh • Assumes 4% electric retail price escalation 3) Reduction in miles driven responding to outages • Average travel time per outage = 30 mins. Average mileage = 20 miles per outage • Reduction in miles driven = 2 miles • Cost per mile = - $1.46 • Assumes 2.2% non-labor escalation	1) 10,000 Blue Sky outages x 9.6 mins time reduction / 60 x 1 x 65 / hr. field labor x labor escalation • **$3.3 Million** 2) 10,000 Blue Sky outages x 40 customers x 0.55 kWh usage x 0.10 $/kWh x retail price escalation • **$0.5 Million** 3) 10,000 Blue Sky outages x 20 miles per outage x 10% reduction x $1.46/mile x retail price escalation • **$0.8 Million** AMS 20 yr. savings **$4.5 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 191, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Avoided "OK on Arrival" Truck Rolls



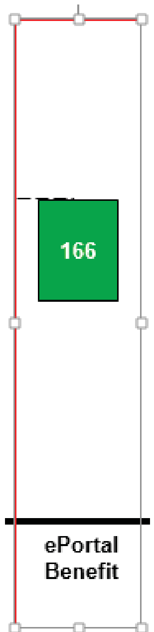
Category	Calculations Assumptions	Total Savings[1]
"OK on Arrival" Avoided Truck Roll Benefits	1) Savings of 1 hr. of crew time per truck roll ($65 per truck roll) • Number of "Ok on arrival" orders for single outage calls avoided = 3,400 • Cost of a truck roll = $65 per truck roll • Assumes 3% labor escalation	1) 3,400 "OK on arrival" orders avoided x $65 per truck roll x labor escalation • **$6.9 Million** AMS 20 yr. savings **$6.9 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 192, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

DISCUSS IN GROUPS

DISCUSS QUESTIONS

ePortal Customer Benefits



Category	Calculations Assumptions	Total Savings[1]
ePortal Customer Benefits	Average monthly bill: • LG&E $82.46 • KU $117.79 • ODP $130.42 ~48% of customers use the portal at least once Of that 48%, approximately 36% will benefit from the energy granularity of AMS Average energy savings is 3%	($82.46/month or $117.79/month or $130.42) * 12 months * escalation factor * 48% * 36% * 3% • **$166 Million** AMS 20 yr. savings **$166 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 193, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to Spanos_-_FINAL.pdf.

DISCUSS IN GROUPS

DISCUSS QUESTIONS

BREAK

Energy delivered

$$E_d = G - (L_g + L_t + L_d + L_n)$$

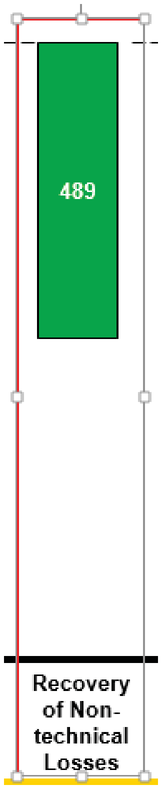
E_d = Energy delivered
G = Gross generation
L_g = Generation losses
L_t = Technical losses – transmission
L_d = Technical losses - distribution
L_n = Non-technical losses

Non-technical losses occur at the point of delivery

- Non-performing and under-performing meters
- Incorrect application of multiplying factors
- Defects in current transformer (CT) and potential transformer (PT) circuitry
- Non-reading of meters
- Pilferage by manipulating or bypassing of meters
- Theft by direct tapping and so on

Pages 91 EPRI Research, Advanced Metering Infrastructure Technology – Limiting No-Technical Distribution In The Future 1016049 http://psc.ky.gov/pscecf/2016-00370/derek.rahn%40lge-ku.com/01252017100851/2-2016_KIUC_DR1_KU_FINAL_w_attachments_%28VOL_1_-_Q01-Q23%29.pdf

Recovery of Non-Technical Losses / Theft Reduction



Category	Calculations Assumptions	Total Savings[1]
Recovery of non-technical losses (Meter Integrity and Theft Reduction)	1) Detect 60% of non-technical line losses through AMS analytics and recover 60% of validated loss • Non-technical line losses = 2% of revenues • % of non-technical line losses detected by AMS Analytics = 60% • Recovery of non-technical line losses detected = 60% • 0.72% increase in revenues is applied to forecasted revenues for non-MV90 customers	1) ~$2.2B revenues for non-MV90 customer * 0.72% increase in revenue • **$489 Million** AMS 20 yr. savings **$489 Million**

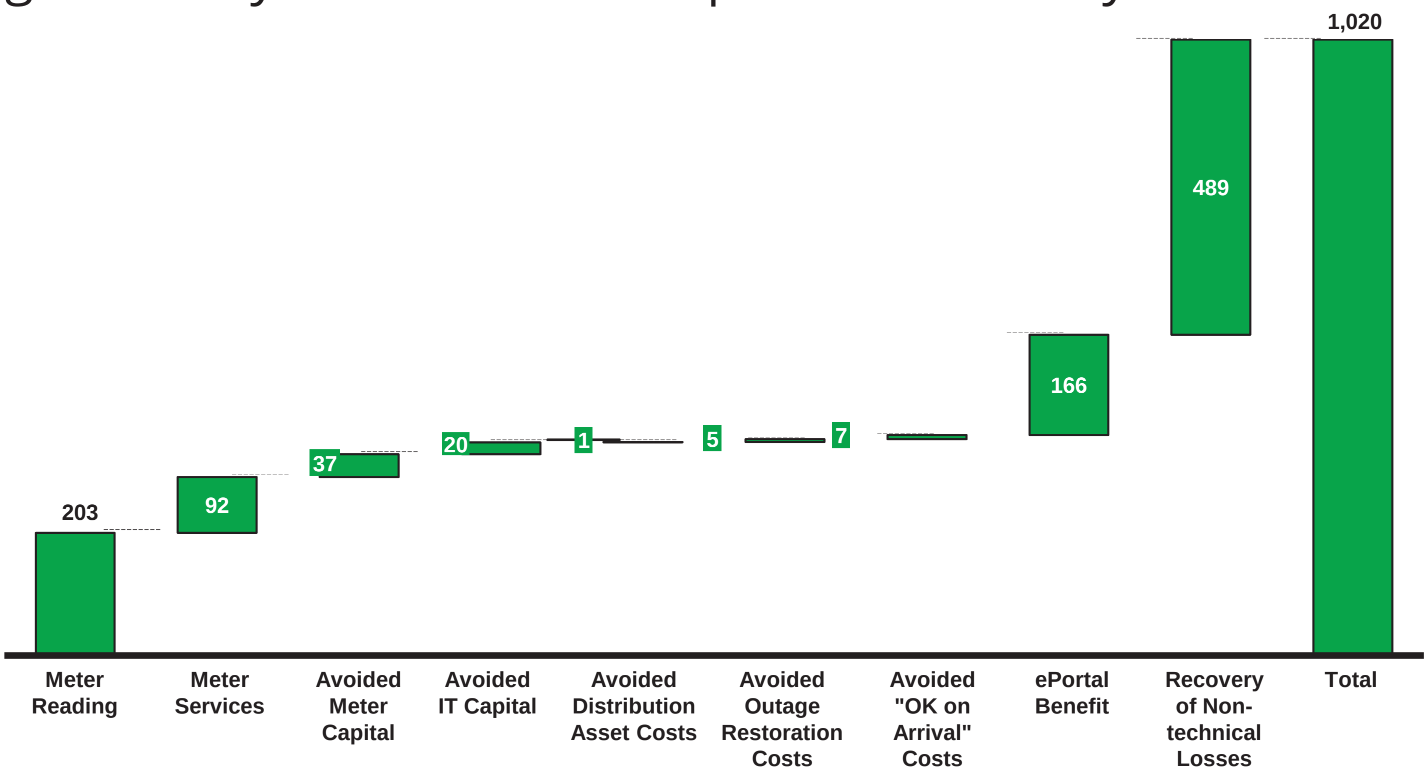
1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 194, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

DISCUSS IN GROUPS

DISCUSS QUESTIONS

AMS Benefits Summary

- Total savings of nearly $1020 Million are possible over 20 years



1) Reference: Page 67, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 _10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

AMS will provide additional “qualitative” customer benefits

There are a number of additional customer benefits from AMS implementation that are not quantified in this analysis. AMS will enable new offerings for customers, improve customer satisfaction through access to data and better engagement with customers. AMS will:

Customer Offerings

- Support customer’s decision on optional rates through more granular data to calculate the savings and costs of different rates
- Provide a platform for future product and service offerings such as energy management, smart thermostats and appliances
- Enable the integration of DER, e.g., solar and electric vehicles to the grid
- Better assure costs are recovered equitably through data analytics and 2 way communication with the meter in detecting losses early
- Provide an avenue for Green Button initiatives
- Provide customer outage notification which can improve customer’s ability to monitor home while away

Customer Operations

- Improve first call resolution through access to customer data
- Support long-term DSM in DLC programs and VVO (Volt/VAR Optimization)

Customer Outage / Power Quality Benefits

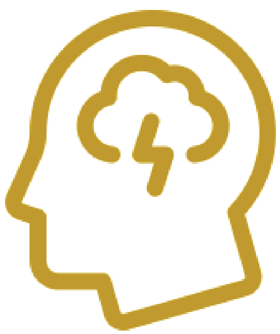
- Save cost of unserved energy due to reduced restoration time
- Enable better outage management and communications with the customer
- Improve power quality due to further development of the ability to monitor and analyze momentary outage and voltage issues

Environmental Benefits

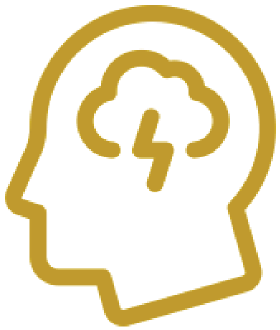
- Reduce GHG emissions through reduction in power produced due to improved system losses, and provide a foundation for GHG state or federal plans

What benefits do you see?

BRAINSTORM



SHARE BRAINSTORMING



BUSINESS CASE SUMMARY

AMS Cost-Benefit Summary

- Costs
  - Project - explained
  - Recurring Costs[1]
    - Capital - From 2022 through 2039, the Company will have limited incremental direct AMS capital expenditure of $25.4 million.
    - O&M - Annual ongoing O&M costs will start at $6.1million in 2022 and escalate to $9.2 million by 2039 and total $135.3 million.
  - Meter Retirement[2]
- Benefits

$ Millions		Nominal Values
Costs		
Total Project Costs (Capital)		(320.4)
Total Project Costs (O&M)		(30.0)
Total Project Costs	**$**	**(350.4)**
Total Recurring Costs (Capital)		(25.4)
Total Recurring Costs (O&M)		(135.3)
Total Recurring Costs	**$**	**(160.8)**
Meter Retirement	**$**	**(39.7)**
Total Lifecycle Costs	**$**	**(550.9)**
Benefits		
Operational Savings		364.9
Recovery of Non-Technical Losses		488.6
ePortal Benefit		166.3
Total Lifecycle Benefits	**$**	**1,019.8**
Net Benefit vs. (Costs)	**$**	**468.9**

Calculation extracted from page 74, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

1) Reference: Page 75, Case 2016-00370 10_-_KU_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

2) Reference: Page 202, Case 2016-00370 10_-_KU_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

ADDITIONAL QUESTIONS

REFLECT

AMS Collaborative Future Sessions

Order	Theme	Summary Description	Estimated Duration
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	½ Day
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	½ Day
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	½ Day
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	½ Day
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	½ Day
7	**Cost / Benefit Recap**	• Review of business case with adjustments	½ Day

SCHEDULE

AUG 22
Costs / Benefits - Baseline

SEP 20
Data Privacy / Sharing
&
Data Empowerment
&
Education

OCT 17
~~Education,~~
Opt-out,
&
Remote Disconnect / Reconnect
&
New Services

NOV 8 ...
~~New Services~~
&
Cost / Benefit - Recap

THANK YOU

Printouts

Meter Reading and Meter Services Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
Meter Reading	• Currently in the LG&E, KU & ODP territories manual meter reading is performed by contractors on a revolving monthly basis. • AMS eliminates all manual meter reading after the MDMS is integrated in 2019 & meters are fully deployed in 2020	• Contractors perform meter reads monthly in the LG&E territory at $0.42/read, and in the KU and ODP territories at $0.70/read. • Assumed a cost escalation factor of 2.2% • Assumed no inspection variance is allowed and 14 PSC inspector are included	Total number of AMS meters * yearly contract value per meter * escalation factor * number of recovery years once MDMS is implemented – the annual cost of the inspectors	AMS 20 yr. savings **$203 Million**
Meter Services	• AMS will largely eliminate the need for technician to perform disconnection services. • Eliminating disconnection services, employee OT will be reduced • Additionally, by geographic area contractor positions will be eliminated while maintaining a sufficient workforce presence • Finally, the material budget will be cut with manual disconnections no longer needed	• Reduced Employee OT at LG&E by 50% starting in 2019 • Reduced Employee OT at KU by 33% in 2019 and by 50% starting in 2020 • Contractor budget for LG&E will be reduced to 4 techs starting in 2019 • Contractor Budget for KU will be reduced to 17 techs in 2019 and 7 techs starting in 2020 • Reduced Purchased Materials by: '18: 0%, '19: 10%, '20: 20%, '21: 20%.	Utilizing the five-year budget define contractor spend, employee OT spend and material spend by year. For the five-year projection used the defined cuts to project savings. Take the 5th year budget savings and project it out with an escalation factor to the end of the recovery period	The meter services technician force is reduced due to AMS digitalizing the process along with the need for OT AMS 20 yr. savings **$92 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 188, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Avoided / Deferred Capital Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
IT	• The IT budget was evaluated for categories of spend that could be avoided or deferred base on the AMS implementation timeline and existing programs it would replace. • It should be noted the savings is considered avoided capital for all but one IT category (SAP CRM/ECC Enhancement)	• Based on the AMS implementation timeline, staffing levels, projected budgets, company priorities, and eliminating programs associated with manual meter reading, along with other factors, IT spend categories were evaluated.	• IT budget evaluation assuming that for deferred capital, the projected budget was steady-state	AMS 20 yr. savings **$20 Million**
Avoided Meter Capital	• The meter capital budget was evaluated for potential savings as the AMS program is implemented. • As a part of AMS implementation, meter inventory will be built up.	• The AMS implementation timeline, projected budgets, company priorities, inventory levels and the different types of meters to be deployed as a part of the AMS program were evaluated to build the savings projections.		AMS 20 yr. savings **$37 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 189, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Avoided Distribution Asset Costs Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
Distribution Asset Costs	• A percentage of distribution transformer failures can be predicted and mitigated with AMS technology, using the AMS data for transformer load management. Accurate transformer loading data allows for asset replacement under a planned outage regime. This results in lower outage duration vs. emergency replacement, and a lower replacement budget. – In 2015 Distribution Transformer outages were responsible for 7,180,149 customer minutes of interruptions. The system SAIDI contribution is 7.4 minutes. There were ~6,000 transformer failures.	1) Savings of 45 min. per outage for a number of the transformer failures (due to equipment failure and avoided) from better prediction of transformer loadings and planned outage regime 1) Protected revenue from reduced outage restoration time	1) Savings of 45 min. per outage for planned replacements • Transformer failures = 6,000 • Number of transformer failures avoided = 250 • Average crew size = 2 • Average hourly loaded cost for crew = $65 pp 2) Protected revenue from reduced restoration time • # of customers in trans-former outages = 5 • Annual avg. energy consumption = 30 MWh • Average retail price = 0.10 $/kWh • Assumes 4% average electric retail escalation	1) 250 outages x 45 min. time reduction / 60 x 2 x 65 / hr. field labor * labor escalation • **$764 Thousand** 2) 250 outages x 5 customers x 2.57 kWh usage x 0.10 $/kWh * retail escalation • **$11.2 Thousand** AMS 20 yr. savings **$0.8 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 190, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

LG&E KU PPL companies

Avoided Outage Restoration Costs Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
Outage Mgmt. Costs	• Reduce cost and impact of outages through ability to more rapidly characterize outage location, type (e.g. momentary vs. sustained), duration, restoration priority, and materials using data from AMS meters	1) 50% reduction in time spent identifying outage location on non-DA circuits (assume 20% of outage duration – CAIDI spent identifying outage location) 2) Protected revenue from reduced outage restoration time 3) Fleet O&M cost reduction from 10% reduction in miles driven responding to outages	1) Reduction in time spent identifying outage location • Outage duration (CAIDI) – Blue Sky = 96 mins. • Reduction in time spent = 9.6 mins. • # of Blue Sky outages = 20,000 • % non-DA circuits = 50% • Average crew size = 1 • Average hourly loaded cost for crew = $65 pp • Assumes 3% labor escalation 2) Protected revenue from reduced restoration time • # of customers in Blue Sky outages = 40 • Annual avg. energy consumption = 30 MWh • Average retail price = 0.10 $/kWh • Assumes 4% electric retail price escalation 3) Reduction in miles driven responding to outages • Average travel time per outage = 30 mins. Average mileage = 20 miles per outage • Reduction in miles driven = 2 miles • Cost per mile = - $1.46 • Assumes 2.2% non-labor escalation	1) 10,000 Blue Sky outages x 9.6 mins time reduction / 60 x 1 x 65 / hr. field labor x labor escalation • **$3.3 Million** 2) 10,000 Blue Sky outages x 40 customers x 0.55 kWh usage x 0.10 $/kWh x retail price escalation • **$0.5 Million** 3) 10,000 Blue Sky outages x 20 miles per outage x 10% reduction x $1.46/mile x retail price escalation • **$0.8 Million** AMS 20 yr. savings **$4.5 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 191, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Avoided “OK on Arrival” Truck Rolls Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
“OK on Arrival” Avoided Truck Roll Benefits	• Number of “OK on arrival” orders – where a crew is dispatched for a reported outage, but find that everything is working properly when they arrive, can be reduced with AMS. AMS meters provide the capability to “ping” a meter to determine whether the meter is communicating. Power is required at the meter in order for the meter to respond to the ping request. Therefore, LKE can use the meter ping to verify that a customer has service without sending a crew, thereby avoiding costs associated with unnecessary truck rolls. This results in crew time savings and fleet mileage savings	1) Truck roll savings for “OK on arrival” orders including ~1 hr. of crew time only	1) Savings of 1 hr. of crew time per truck roll ($65 per truck roll) • Number of “Ok on arrival” orders for single outage calls avoided = 3,400 • Cost of a truck roll = $65 per truck roll • Assumes 3% labor escalation	1) 3,400 “OK on arrival” orders avoided x $65 per truck roll x labor escalation • **$6.9 Million** AMS 20 yr. savings **$6.9 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 192, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

LG&E KU PPL companies

ePortal Customer Benefits Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings[1]
ePortal Customer Benefits	• The web portal will give customers access to their electric usage data. This granular data, in combination with educational materials, will give customers insights into their electric energy usage and enable them to reduce it.	• Based on preliminary results of the pilot, LG&E/KU is experiencing 48% of electric customers use the portal at least once. • LG&E/KU estimates that 36% of those customers who have utilized the portal at least once identify value in the electric usage information provided and continue to use the portal to draw insights into their consumption patterns and adjust their behavior to save energy. • Based on a smart grid consumer collaborative report, between 2 to 5% reduction in usage is projected for active users. We have projected a 3 % energy savings for those customers actively using the portal.	Average monthly bill: • LG&E $82.46 • KU $117.79 • ODP $130.42 ~48% of customers use the portal at least once Of that 48%, approximately 36% will benefit from the energy granularity of AMS Average energy savings is 3%	($82.46/month or $117.79/month or $130.42) * 12 months * escalation factor * 48% * 36% * 3% • **$166 Million** AMS 20 Yr. Savings **$166 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 193, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Recovery of Non-Technical Losses / Theft Reduction Value Levers

Category	Description	Levers	Calculation Assumptions	Total Savings
Recovery of non-technical losses (Meter Integrity and Theft Reduction)	• Identify endpoints with usage anomalies and meter events that indicate potential intentional theft, meter configuration errors and meter malfunctions – E.g. – Intermittent outages coupled with usage reductions indicating physical meter breach or bypass (e.g. tilt, rotation, reverse flow) – Anomalous load profile (statistically significant variation) indicating meter disable or jumpering – Anomalies or meter events suggesting meter malfunction or configuration error (i.e. measurement errors, missing interval data)	1) Detect 60% of non-technical losses including theft and meter malfunctions through AMS analytics, and assume recovery of 60% of validated loss through back bill, correction, or disconnection	1) Detect 60% of non-technical line losses through AMS analytics and recover 60% of validated loss • Non-technical line losses = 2% of revenues • % of non-technical line losses detected by AMS Analytics = 60% • Recovery of non-technical line losses detected = 60% • 0.96% increase in revenues is applied to forecasted revenues for non-MV90 customers	1) ~$2.2B revenues for non-MV90 customer * 0.72% increase in revenue • **$489 Million** AMS 20 yr. savings **$489 Million**

1) Lifetime savings assume 2.2% escalation over lifetime
2) Reference: Page 193, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Business Case Acronyms

- **ADA** Advanced Distribution Automation
- **ADMS** Advanced Distribution Management Systems
- **AHE** AMS Head-End
- **AMS** Advanced Metering Systems
- **BPEM** Business Process Exception Management
- **CAPEX** Capital Expenditure
- **CIS** Customer Information System
- **CO2** Carbon Dioxide
- **CSRs** Customer Service Representatives
- **CT** Current transformer
- **DA** Distribution Automation
- **DERMS** Distributed Energy Resource Management Systems
- **DERs** Distributed Energy Resources
- **DMS** Distribution Management System
- **DR** Demand Response
- **DSM** Demand Side Management
- **EE** Energy Efficiency
- **ePortal** Web Portal Presentment
- **FAN** Field Area Network
- **FLISR** Fault Location, Isolation and Service Restoration
- **GHG** Greenhouse gas
- **GIS** Geographic information system
- **HAN** Home Area Network
- **IEDs** Intelligent Electronic Devices
- **IHD** In-home device
- **IOUs** Investor Owned Utilities
- **IT** Information Technology
- **IVR** Interactive voice response
- **KPSC** Kentucky Public Service Commission
- **KU** Kentucky Utilities
- **LG&E** Louisville Gas & Electric
- **MAM** Meter Asset Management
- **MDMS** Meter Data Management System
- **MOC** Metering Operations Center
- **NPV** Net present value
- **O&M/ OPEX** Operations and Maintenance
- **OMS** Outage management system
- **PEVs** Plug-in electric vehicles
- **PON** Power outage notifications
- **PPLEU** PPL Electric Utilities
- **PRN** Power restoration notifications
- **PT** Potential transformer
- **PV** Photovoltaics
- **RF Mesh** Radio Frequency
- **SCADA** Supervisory Control and Data Acquisition
- **SGCC** Smart Grid Consumer Collaborative
- **SMS** Short Message Service
- **TOD/TOU** Time of Day / Time of Use
- **VEE** Validate, Estimate, Edit
- **VVO** Volt/VAR Optimization
- **WAN** Wide Area Network

Requested Waivers in Business case

Waiver	Description	Reason	Savings
807 KAR 5:006, Section 7(5)	• Section 7(5)(a) requires a utility to read each customer's meter at least quarterly • Section 7(5)(b) requires that a meter be read manually at least once during each calendar year.	• Obtaining a monthly remote meter reading via AMS constitutes a meter reading	• Reads are collected daily to satisfy quarterly requirement • **$2.4 M Savings**
807 KAR 5:006, Section 14(3)	• Requires the Company to inspect the condition of meter and service connections before providing service to a new customer so that prior or fraudulent use of the facilities shall not be attributed to the new customer	• Meters communicate tamper	• Reduction in annual costs of inspections • **$3 M Savings**

Reference: Page 78, Case 2016-00370 10_-_KU_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Additional Requested Waivers with future savings

Waiver	Description	Reason	Savings
807 KAR 5:006, Section 26 (4)(e) & 807 KAR5:006, Section 26 (5)(a)(2)	• Perform inspections on electric meters every two years and gas meters every three years • AMS provides electronic information and alarms including tamper (Section 4.6 and Appendix A-3)	• Two-year and three-year inspections may be met with the electronic information provided by the AMS and thus not require periodic physical inspections.	• Reads, information and alarms are collected daily to satisfy requirement • **$1.2 M Savings annually**
807 KAR 5:041 Section 16 & KPSC Case 2005-00276	• Perform sample and periodic meter testing programs. • Seeking to suspend its existing sample program in the deployment years and proposes to resume the sample program post-AMS deployment	• Contractors and employees doing this work today will be assigned other work (testing new meters) during the deployment phase	• **$167,000 Savings annually**
807 KAR 5:041 Section 15 (3)	• Suspend removal testing and proposes to resume it post-AMS deployment. • Request permission to dispose of removed meters immediately although they have not been tested for accuracy, as these meters will not then be returned to service.	• Over the last six years, more than 99% of KU and LG&E electric meters tested have been within +/- 2%. Of the less than 1% of meters that are fast or slow, 82% are slow and 18% are fast. • 98% of LG&E gas meters tested have been within +/- 2%. Of the 2% that are fast or slow, 67% are slow and 33% are fast.	• Reads are collected daily to satisfy quarterly requirement • **$3.3 M Savings**
807 KAR 5:006 Section 19	• Clarification. Request that all meters are included in the exception, not just meters in service.		

Reference: Page 78, Case 2016-00370 10_-_KU_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf.

Requested additional Waivers

807 KAR 5:006, Section 26 (4)(e) and 807 KAR5:006, Section 26 (5)(a)(2) require the Company to perform inspections on electric meters every two years and gas meters every three years. Annual cost to comply with this regulation is $1.2 million. AMS provides electronic information and alarms as described in Section 4.6 and more fully shown in Appendix A-3. This electronic information includes tampering alarms. Thus, the Companies will have notice if a meter is tampered with and can follow-up with a physical inspection. Other information delivered from the meter provides the Company details of the general condition of every meter in the system on a daily basis. Consequently, the intent of the two-year and three-year inspections may be met with the electronic information provided by the AMS and thus not require periodic physical inspections.

807 KAR 5:041 Section 16, and KPSC Case 2005-00276 require the Company to perform sample and periodic meter testing programs. The Company seeks to suspend its existing sample program in the deployment years and proposes to resume the sample program post-AMS deployment. Annual cost to comply with this regulation is $167,000. The estimated savings will be in the form of additional workforce capacity since this is a temporary suspension of the requirement. The contractors and employees doing this work today will be assigned other work (testing new meters) during the deployment phase and will return to testing sample meters after deployment.

807 KAR 5:041 Section 15 (3) requires the Company to test all removed meters. As reported quarterly to the Kentucky Public Service Commission, the Company has demonstrated that the vast majority of meters tested are operating accurately. Over the last six years, more than 99% of KU and LG&E electric meters tested have been within +/- 2%. Of the less than 1% of meters that are fast or slow, 82% are slow and 18% are fast. Therefore, approximately 0.12% of electric meters are fast. 98% of LG&E gas meters tested have been within +/- 2%. Of the 2% that are fast or slow, 67% are slow and 33% are fast. Therefore, approximately 0.76% of gas meters are fast. Labor costs to comply with this regulation are $3.3 million. The Company suggests that this is a high cost to customers to identify roughly 0.12% of electric customers and 0.76% of gas customers possibly impacted by a fast meter. The Company seeks to suspend its removal testing and proposes to resume it post-AMS deployment. Additionally, the Company will request permission to dispose of removed meters immediately although they have not been tested for accuracy, as these meters will not then be returned to service.

807 KAR 5:006 Section 19 states, "A utility shall make a test of a meter upon written request of a customer if the request is not made more frequently than once each twelve (12) months." On its face, this requirement would appear to apply only to meters still in service, not to meters already removed from service. But out of an abundance of caution, the Company will ask the Commission to grant the Company a deviation from Section 19 regarding all meters the Company removes as part of the full AMS deployment. The reasons for the deviation are the same as those given above for the Company's requested deviation from 807 KAR 5:041 Section 15(3) concerning testing of meters removed from service.

AMS Collaborative
August 22 Session Summary

LG&E KU
PPL companies

AMS Collaborative Session #2 – Logistics

Tuesday, August 22, 2017
9:00 AM – 3:30 PM ET
Noah's

Collaborative Objectives:

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests and questions

Session #2 Objectives:

- Review cost / benefit baseline provided in business case
- Present the business case methodology
- Encourage discussion and questions to clarify information
- Understand business case areas that are important to your constituents

PARTICIPANTS

Participant	Organization
Mark Zoeller	Louisville Metro
Lisa Kilkelly	Association of Community Ministries
Ron Willhite	KSBA
Richard Dugas	LFUCG
Kent Chandler	OAG
Melissa Tibbs	CAC
Wallace McCullen Barry Zalph	Sierra Club
Cathy Hinko	MHC
David Huff Jonathan Whitehouse Sam Stickler Wendy Wagoner Rick Lovekamp Meredith Needham Lora Aria Cheryl Williams	LG&E / KU
Jamie Hart Phyllis Goodson Maria Ferreira-Cesar	Accenture
Julie Gieseke	Accenture / Map the Mind

AGENDA

Topic	Time	Host
Safety Moment, Introductions	9:00 AM	Phyllis Goodson
AMS Introduction	9:30 AM	David Huff
Break	10:15 AM	
Costs	10:30 AM	Jonathan Whitehouse, Sam Stickler
Small and large group discussion	11:10 AM	Participants, Jonathan Whitehouse, Sam Stickler
Lunch	11:30 AM	
Benefits and small group discussions	12:00 PM	Jonathan Whitehouse, Sam Stickler, Participants
Benefits large group discussion	1:45 PM	Participants, Jonathan Whitehouse, Sam Stickler
Break	2:15 PM	
Business case questions and debrief	2:30 PM	Phyllis Goodson, Jamie Hart
Summary and next steps	3:00 PM	David Huff

AMS Collaborative Session #2

Approach:
- Casual atmosphere to encourage openness
- Structured format to address all key areas of the business case
- Visual Illustrator to capture discussion

Description:
- AMS Overview of LG&E/ KU advanced meters pilots and programs
- Detailed walk through of costs and benefits and how they were calculated
- Opportunity to discuss in groups and then ask questions to understand detailed makeup of business case numbers and calculations
- Post-its captured small group discussion on costs

Logistics:
- 4-6 people per table to develop questions / discuss
- Direct Q&A with business case SMEs

Costs:
Discussed Costs across the following categories and numbers as filed for Capex and OpEx.

- Meters
- Network and Network Management
- Information Technology
- System Integration
- Program Management
- Communications
- Change Management
- Contingency

Benefits:
Discussed Benefits across the following areas for both the utility and customer.

- Meter Reading
- Meter Services
- Avoided Costs
  - Meter capital
  - IT capital
  - Distribution asset costs
  - Outage restoration costs
- "OK on arrival" costs
- ePortal Benefits
- Recovery of non-technical losses

Two Follow-up Questions from the Collaborative Session

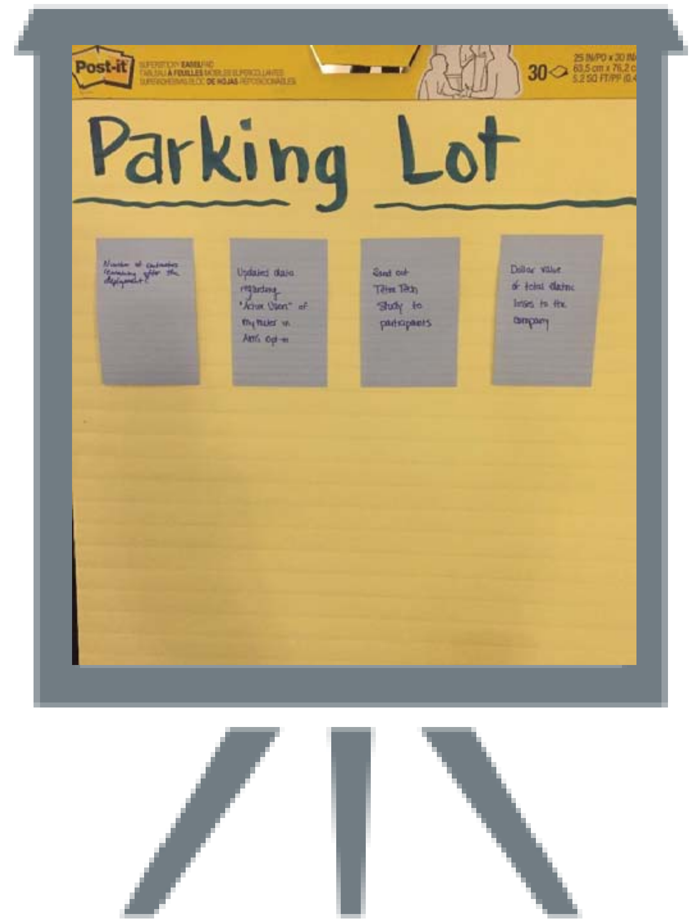
1. What is the total number of smart meters installed across the US?
   - According to the U.S. Department of Energy's Energy Information Administration, as of the end of 2014 there were almost 144 million electric meters in the U.S. Of those, 40.7% were smart meters, 32.6% were automated meter reading ("AMR") meters, and about 26.7% were purely electro-mechanical meters (i.e., having no communications ability) of the kind the Companies currently predominantly have in service. And the deployment of smart meters has grown consistently over time, from just 7 million deployed in 2007 to well over 50 million today, with several million being added each year.

   - This information was updated in late 2016 on the EIA.gov website. https://www.eia.gov/tools/faqs/faq.php?id=108&t=3 . In 2015, U.S. electric utilities had about 64.7 million advanced (*smart*) metering infrastructure (AMI) installations. About 88% of the AMI installations were residential customer installations.

2. What is the remaining life of the meters to be retired?
   - In the rate case LG&E and KU provided answers. They are
     - LG&E – Existing meters have an average book useful life of 25 years.
     - KU – Existing meters have an average book useful life of 28 years.

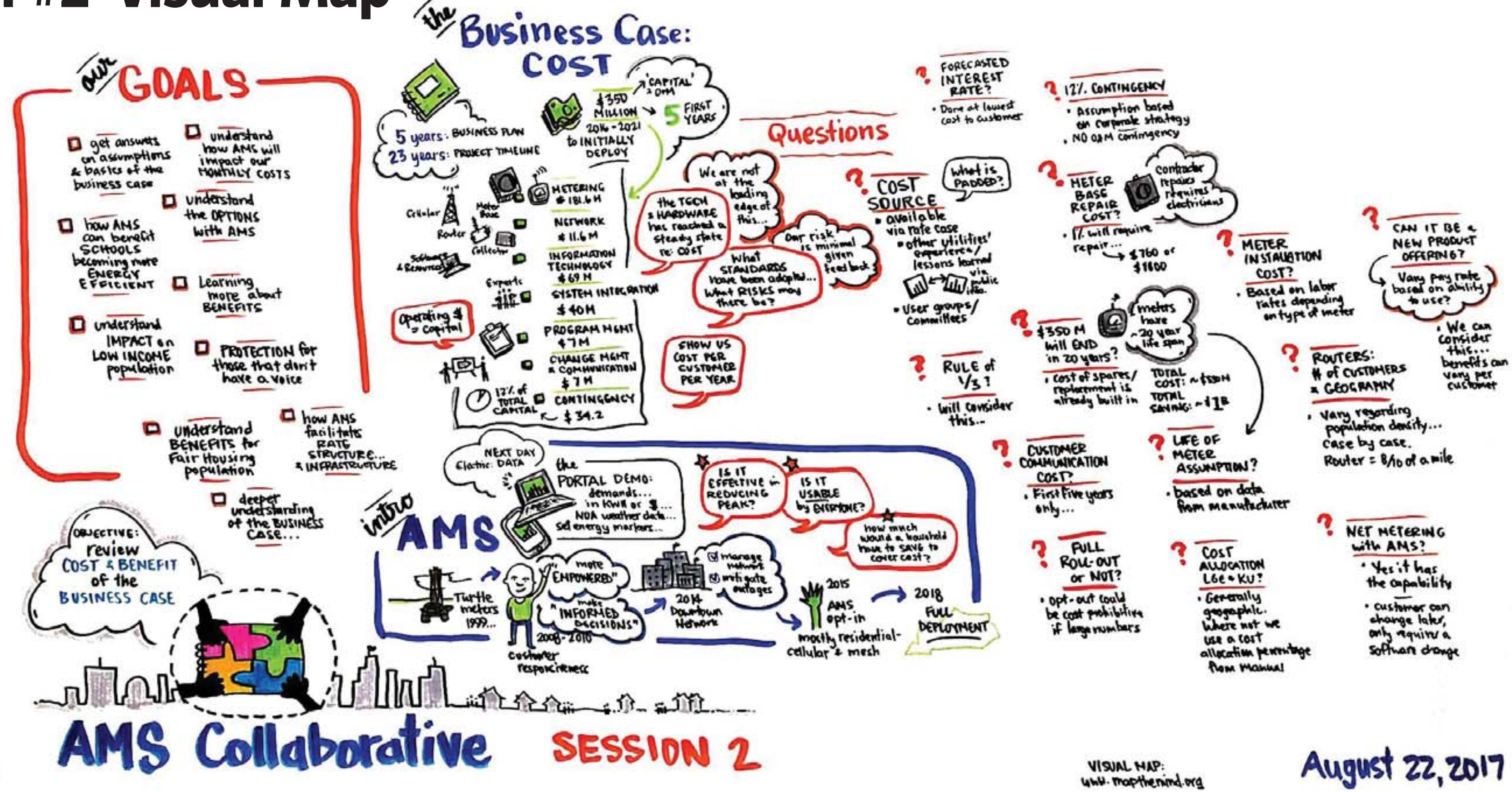
Parking lot questions

- Number of contractors after deployment
- Updated data regarding “Active Users” of MyMeter in AMS Opt-in
- Share Tetra Tech Study to participants (provided link 8/25/2017)
- Dollar value of total electric losses to the company

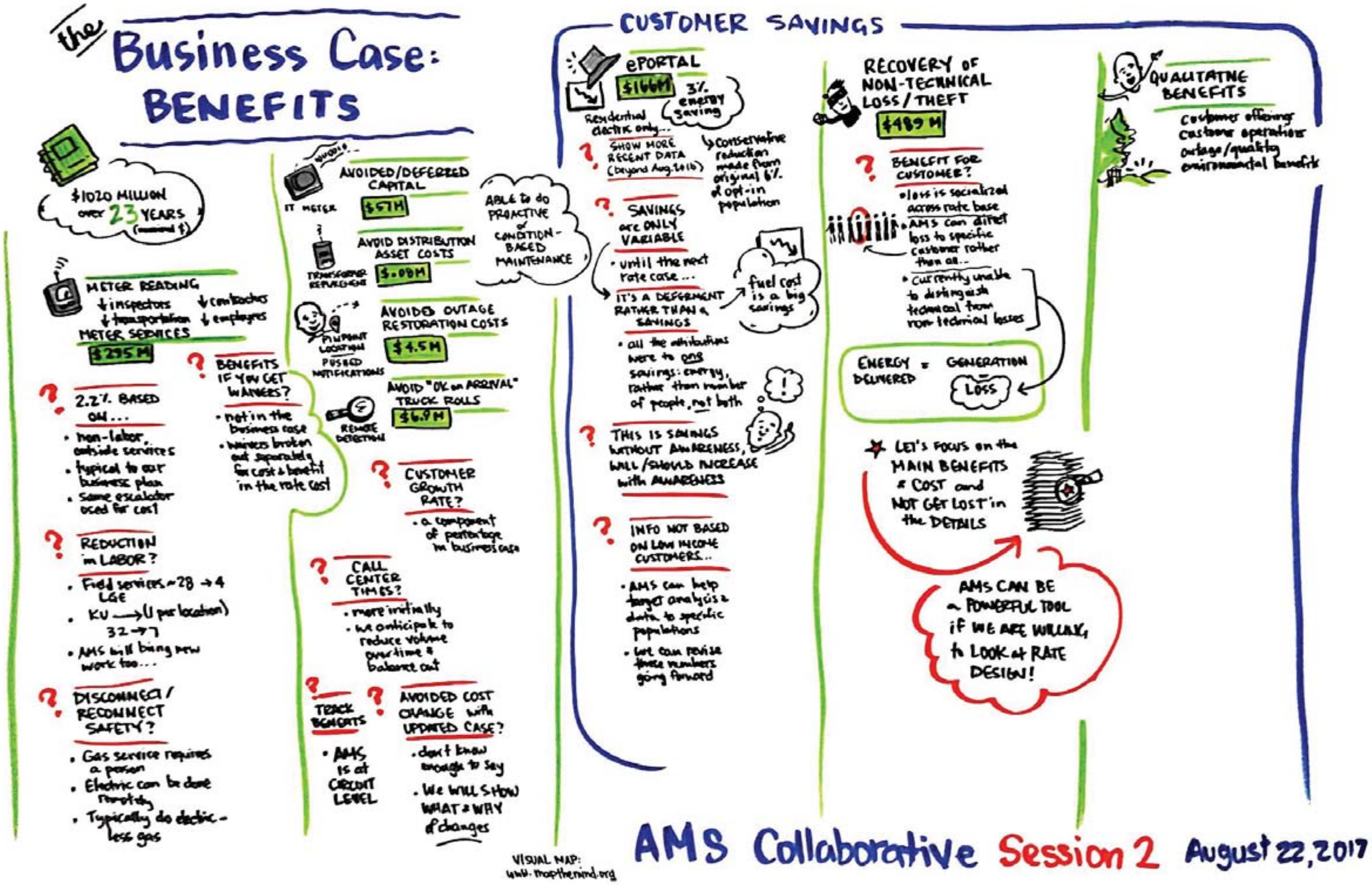


Session 3 will reserve time for additional business case discussion for any unanswered questions

AMS Collaborative
Session #2 Visual Map



AMS Collaborative Session #2 Visual Map (con't)



AMS Collaborative
Upcoming Session Dates

FUTURE MEETINGS

- Meetings to be held in Frankfort, KY
- Meeting times will adjust to 8:30 a.m. to 4:00 p.m. to allow for all materials to be covered and provide ample time for discussion and questions

SEP 20	OCT 17	NOV 8 …
Data Privacy / Sharing & Data Empowerment & Education	Remote Disconnect / Reconnect & New Services	Cost / Benefit - Recap

AMS Collaborative
Session 3 - September 20, 2017

PPL companies

Exhibit DEH-3
Page 1 of 79
Huff

Safety Moment

EXITS and EVACUATION ROUTES

- Exits
  - Main entrance

- If evacuation is required
  - Go to the far end of the parking lot across from the main entrance of the building

- Restrooms
  - Down the hall

September is National Preparedness Month

With the recent damage of 2 major storms, we're reminded how devastating disasters can be and how quickly they can strip us of some of our most basic resources.

How to avoid being another victim:

1. Make a plan.
2. Stock up on emergency items.
3. Make a kit now- before an emergency.
4. Take your emergency planning on the go.
5. Keep informed.

LG&E KU
PPL companies

Agenda – Collaborative

Topic	Time	Host
Safety Moment, Agenda, Session 2 Review, Framework of Session 3, and Introductions	9:00 AM	Phyllis Goodson
Data Security & Privacy	9:30 AM	David Huff
Data Access	10:00 AM	David Huff
Break	10:30 AM	
Data Access Exercises	10:45 AM	Phyllis Goodson, Jamie Hart
Data Use and Empowerment	11:30 AM	Wendy Wagoner
Data Use and Empowerment Exercise	12:00 PM	Phyllis Goodson, Jamie Hart
Lunch	12:30 PM	
Education	1:00 PM	Wendy Wagoner
Education Exercises	1:30 PM	Phyllis Goodson, Jamie Hart
Recap Session 3 and next steps	2:00 PM	Phyllis Goodson
Break	2:15 PM	
Discuss any remaining business case questions	2:30 PM	David Huff

AMS Collaborative Objectives

OVERALL

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests

TODAY

- Review current policies and processes on privacy
- Discuss needs of constituency for data access
- Identify how users might be empowered with data and what steps are needed
- Seek to understand educational needs for users
- Discuss any open business case questions

AMS Collaborative Session 2 Review

AMS Collaborative Session #2

Approach:
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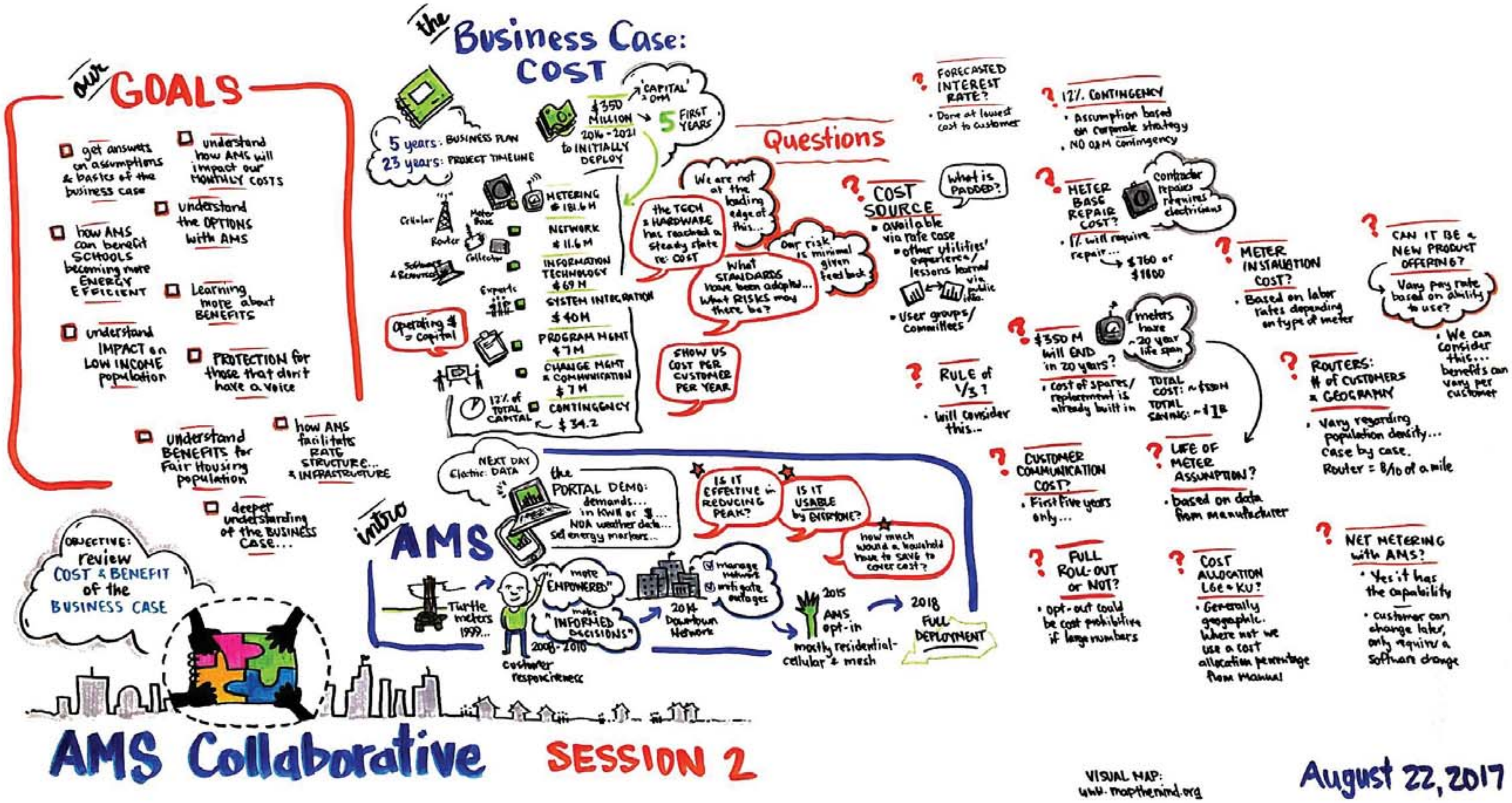
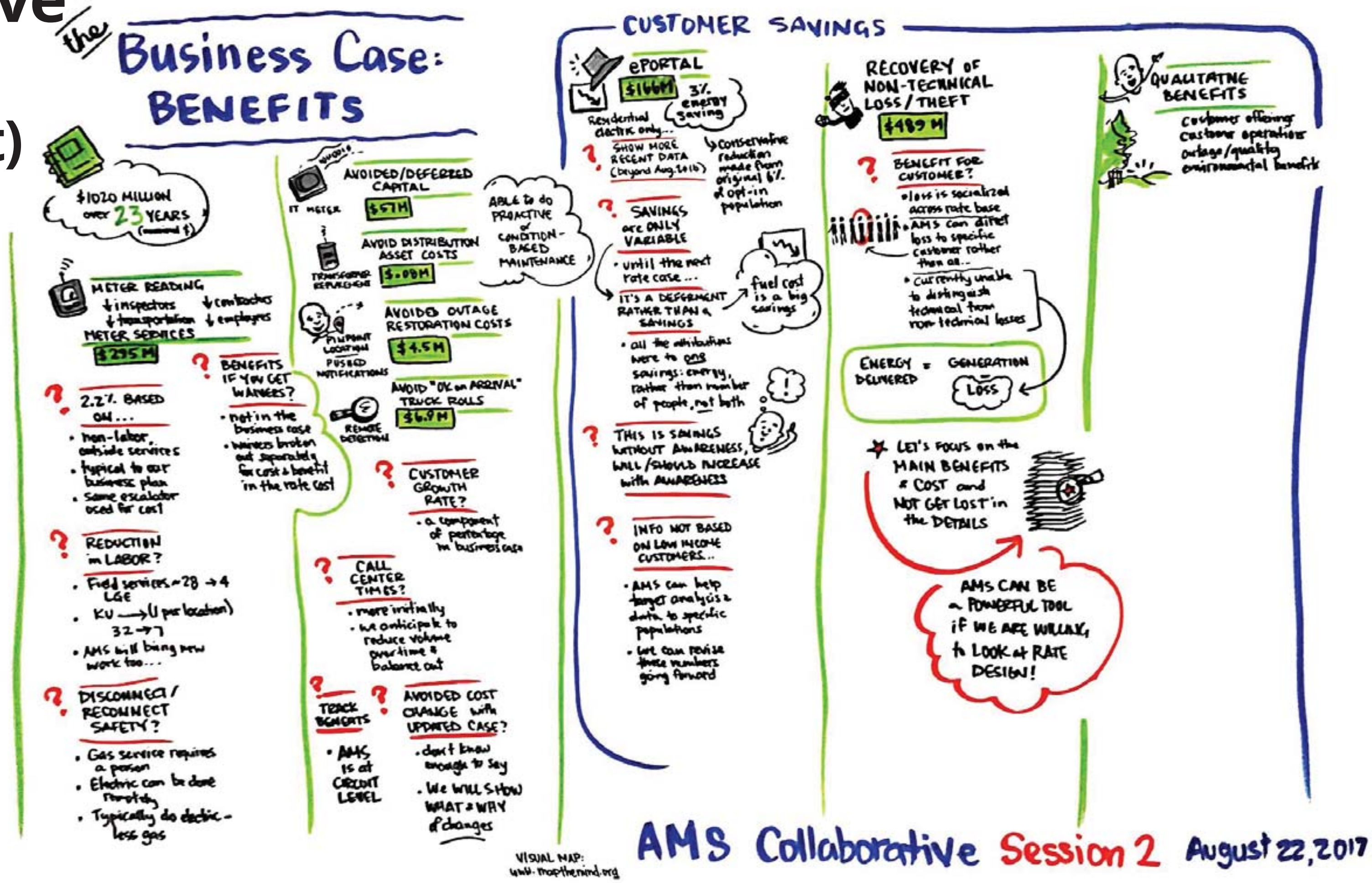
AMS Collaborative Session #2 Visual Map



AMS Collaborative Session #2 Visual Map (con't)



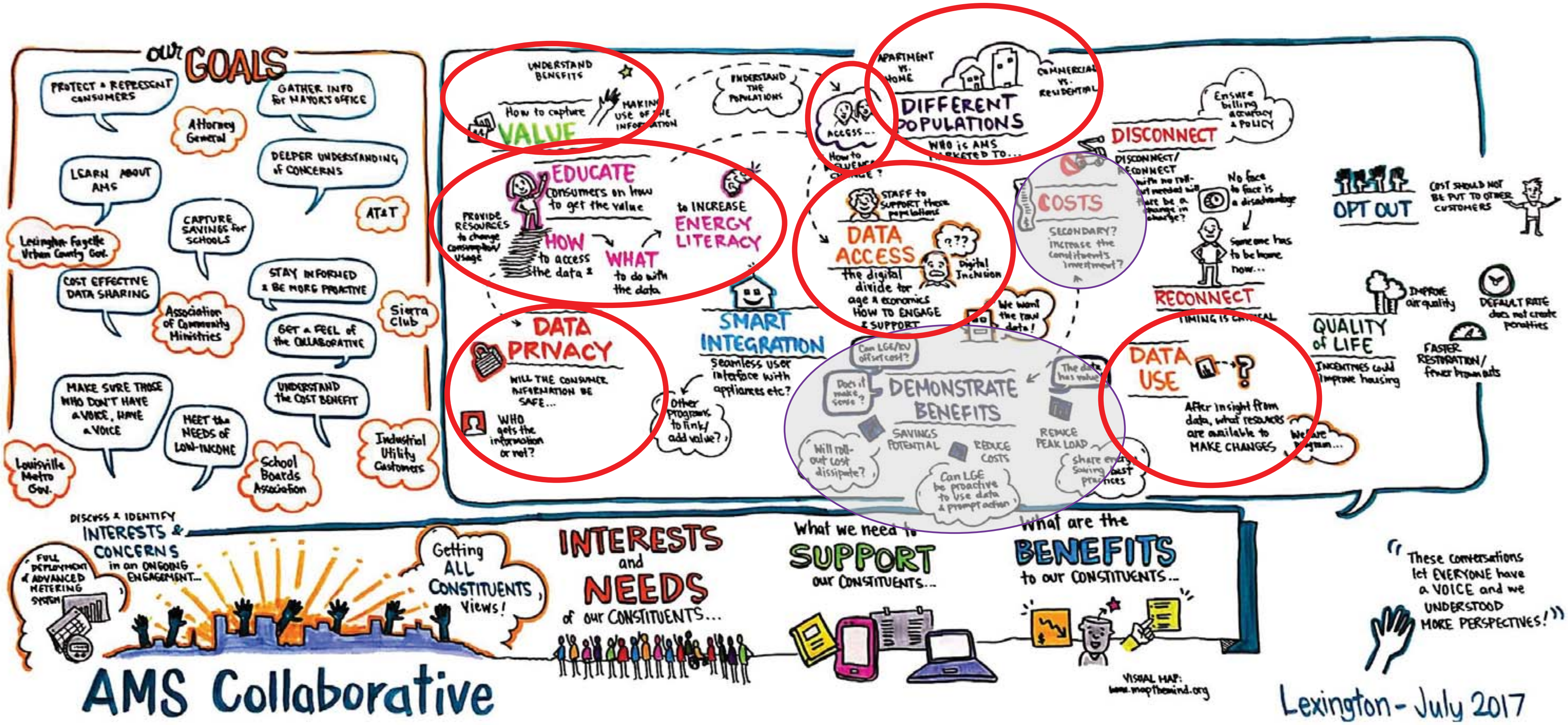
AMS Collaborative

Order	Theme	Summary Description	Estimated Duration	Planned Session
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day	2
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	1/3 Day	3
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	1/3 Day	3
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	1/3 Day	3
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	1/3 Day	4
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	1/3 Day	4
7	**Cost / Benefit Recap**	• Review of business case with adjustments	Full Day	5

SCHEDULE

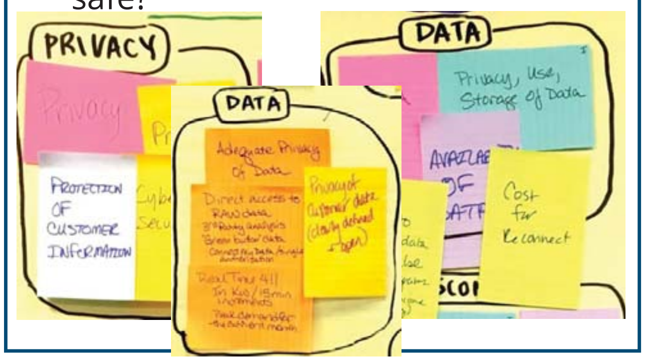
AUG 22	SEP 20	OCT 17	NOV 8 ...
Costs / Benefits - Baseline	Data Privacy & Data Empowerment & Customer Education	Opt-out, & Remote Disconnect / Reconnect & New Services	Cost / Benefit - Recap

AMS Collaborative Session #1 Visual Map

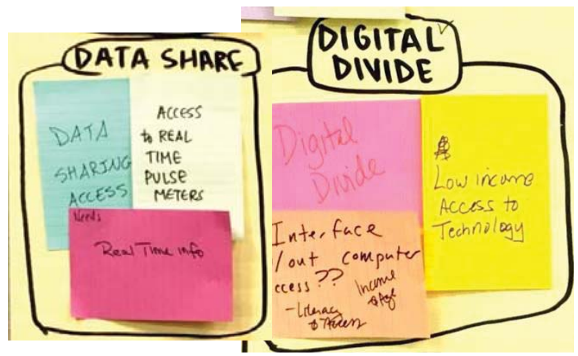


Session 3 Framework

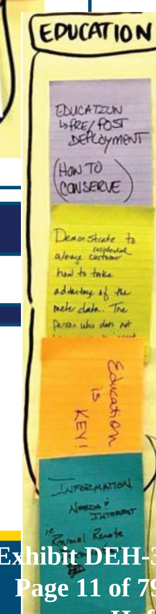
Data Security & Data Privacy
- How does LG&E/KU protect your data?
- How does LG&E/KU use your data?
- How can customers keep their data safe?



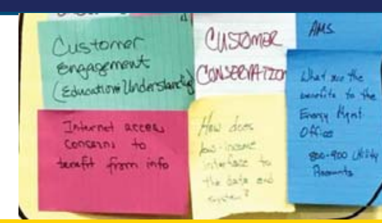
Data Access
- Types of data
- LG&E/KU access to customer data
- Customer access to data
- Third-party access to data



Data Use & Empowerment
- Data enabled by AMS
- How does AMS data drive informed energy saving decisions?



Customer Education
What is AMS? • Installation communications and information • Energy literacy



LG&E and KU
Data Security

Data Security at LG&E/KU

What it is…

Information Security is the collection of technologies, processes and practices coordinated to protect networks, hardware and software from attack, damage, or unauthorized access.

Corporate Information Security Strategy

Protect			
Network	Hardware	Software	Data
Through			
People	Technology	Processes	Practices

AMS Security

Information Security Corporate Strategy Summary

- Best practice cybersecurity programs include layered defenses; regulatory oversight; external third-party assessments; and internal governance.

- The industry is committed to the vigilance and investments necessary to provide the safe and reliable service its customers expect and deserve.

- All electric utilities have a common objective: Protecting the nation’s critical electric and gas infrastructures.

- Information security is an on-going journey with ever changing paths, modes, and terrain.

Partnerships and Intelligence / Information Gathering

LG&E and KU partner with a number of industry and governmental entities to ensure the most timely and robust intelligence is considered when developing security protocols

- National Cybersecurity and Communications Integration Center (NCCIC) United States Computer Emergency Readiness Team (US-CERT)
- Cyber Risk Information Sharing Program (CRISP)
- Electricity Sector Information and Analysis Center (ES-ISAC)
- North American Transmission Forum (NATF)
- Louisville offices of the DHS and the Federal Bureau of Investigation (FBI)
- Local law enforcement and emergency management agencies

AMS-Specific Security

Benefits of Meter and Network Infrastructure Advanced Security

- ✓ Align with current regulatory technology standards and guidelines from NERC and NIST that evolves with changing requirements.
- ✓ Provide immediate, tangible security for data in transit through the network.
- ✓ Enable Corporate IT to incorporate world-class encryption and authentication solutions into the AMS network without significant software customization expense.

LG&E and KU will continue to assess and maintain the cybersecurity framework for the AMS program to align with standards, regulations, and industry best-practices

1: Section 4.1.3, Pg. 219, NISTIR 7628).

Examples of AMS-Specific Security

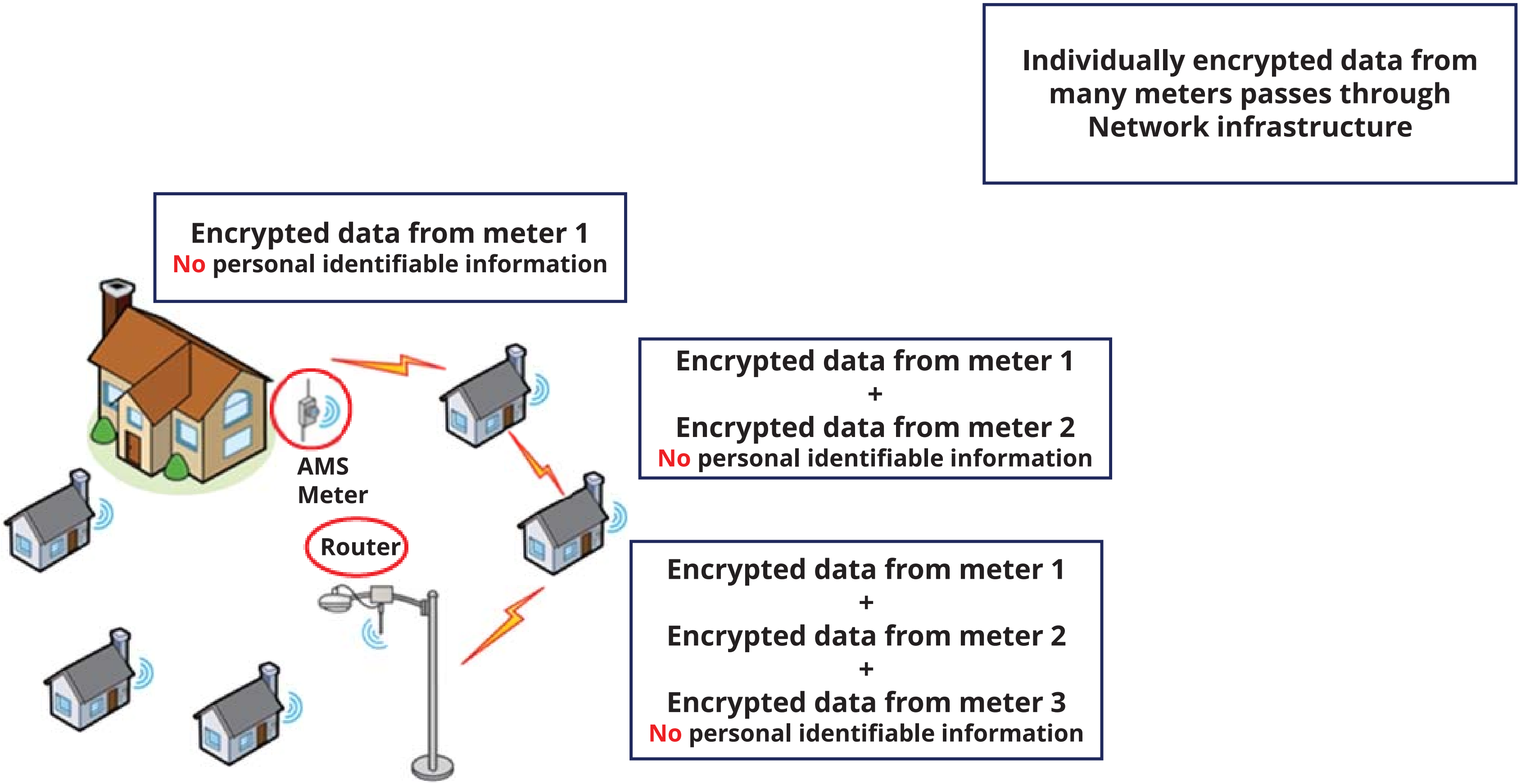
National Institute of Standards and Technology[1]: "[A] meter, collector, or other power system device should not be subject to a break-once break-everywhere scenario, due to the use of one secret key or a common credential across the entire infrastructure. Each device should have unique credentials or key material such that compromise of one device does not impact other deployed devices. "

✓ **Device Specific Encryption Keys**
Each device is provisioned with unique encryption keys used to protect the privacy and integrity of data and commands sent to and from the device.

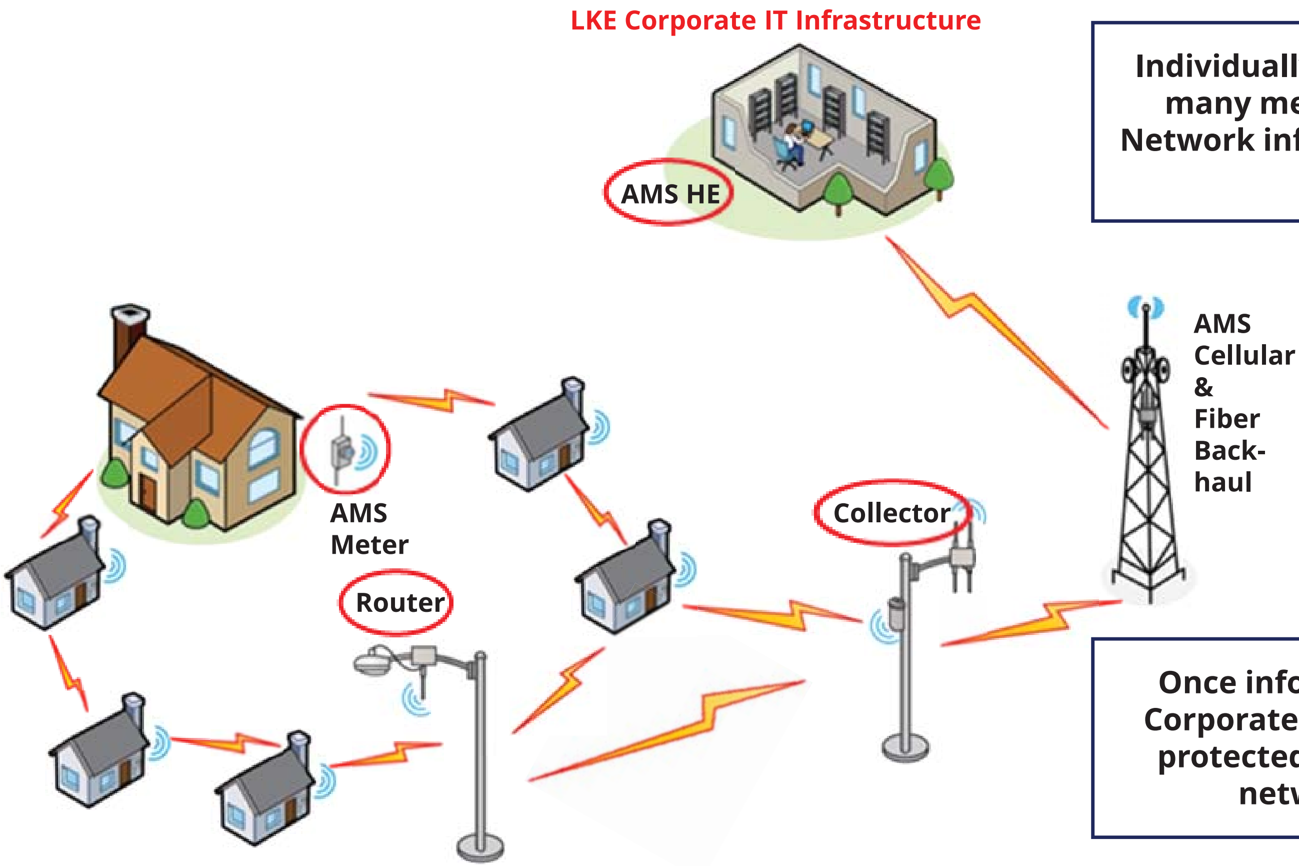
✓ **Downstream Message Authentication**
Verify messages using a digital signature to ensure commands originated from a trusted source.

1: Section 4.1.3, Pg. 219, NISTIR 7628).

Data security through AMS communication systems



Data security through AMS communication systems



Individually encrypted data from many meters passes through Network infrastructure to the AMS Head End

Once information reaches the Corporate IT infrastructure, it is protected by our firewalls and network protection

Data Privacy

Privacy Policy [1] - How LG&E/KU protects

We will make every effort to protect and preserve customer account information and will not share specific information about your account with third parties, without written authorization or unless we are required to do so by a court order, subpoena or other compulsory process, or by operation of law.

Customer account information may be used by us in the following representative ways:

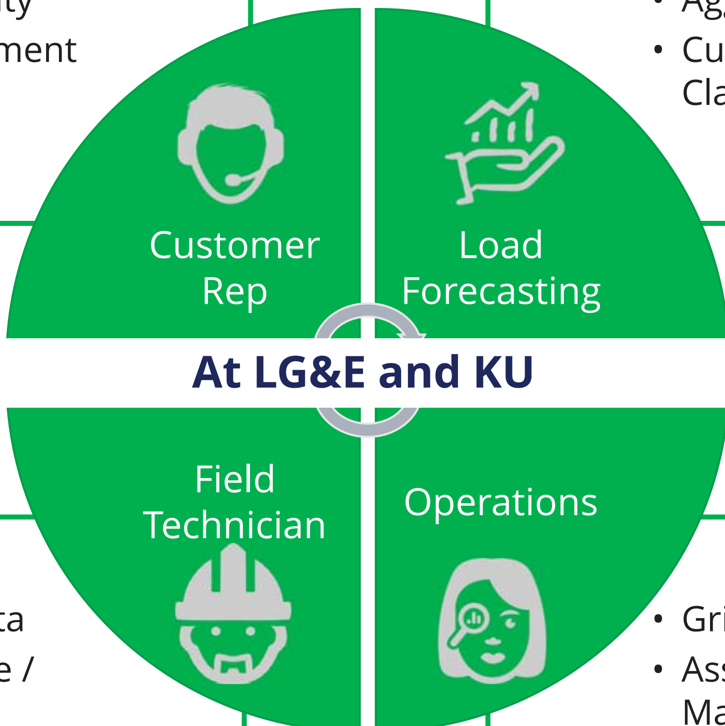
- To verify the existence of a customer's energy service;
- To communicate with a customer and handle customer requests;
- To compile information about how our Web site is reached and used;
- To compile research that does not identify the customer as an individual, group or entity other than age group and gender;
- To contact our customers about other products or services offered by our alliance partners; and
- To collect debts owed by a customer.

1) https://lge-ku.com/privacy

Access of customer data within the Company

- Billing Integrity
- Billing & Payment
- Advisory

- Aggregated Data
- Customer Classes (R, C, I)



- Location Data
- Maintenance / Service

- Grid Health
- Asset Management

Data is also shared with external parties in the following controlled scenarios…

- Contractor access to data is tightly controlled through confidentiality agreements, contractual specifications, access controls, etc.
- Response to data requests in aggregated format to government, research, energy efficiency agencies, etc.. The Companies ensure that data is not personally identifiable
- As directed by the customer

How can customers keep their data safe?
Registration Information and Requirements, and Privacy[1]

- When you register for with LG&E and KU, we may ask you to give us certain identifying information ("Registration"). You agree to provide true, accurate, current and complete information about yourself. You also agree not to impersonate any person or entity, misrepresent any affiliation with another person, entity or association, use false headers or otherwise conceal your identity from LG&E or KU for any purpose. We agree to treat with care the information you entrust to us, in accordance with the disclosures we give during the Registration process and in our privacy policy.

- For your protection and the protection of **our other customers and Web site users**, we ask you not to share your Registration information (including passwords, usernames, and screen names) with another person for the purpose of facilitating their access and unauthorized with LG&E and KU. You alone are responsible for all messages posted, statements made, or acts or omissions that occur with LG&E and KU through the use of your Registration information.

1) https://lge-ku.com/terms

Data privacy – registration and verification guidelines

Customer Access

- Registration requires the new account holders to provide legal name and at least one full personal identifier (e.g. SSN, driver's license #).
- Customers can access their account through multiple channels (Customer Call Center, MyAccount) only after they provide personal identifying information (e.g. name and last 4 of SSN, name and driver's license) or by presenting picture ID or a bill when accessing account in person at a Customer Service Center.
- Customers can provide account access to others:
  - To provide full account access, account holder must call and provide identifying information for new access holder. This gives access holder ability to obtain account information via web, email, IVR (all channels).
  - Account holder can provide all necessary information for additional people to set up MyAccount access to the account. This allows access holder to view account information and make web-available changes, but cannot access information via IVR.

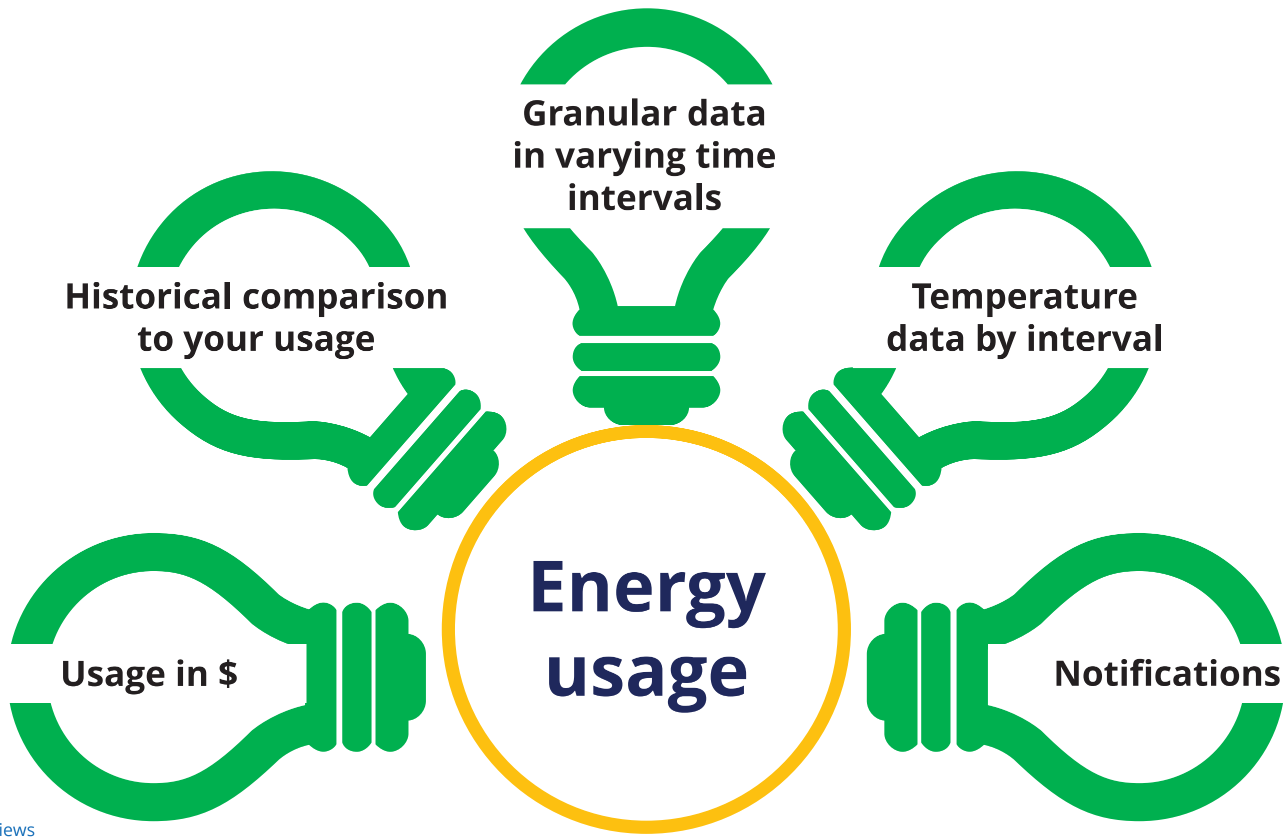
Customer-enabled Third Party Access

- **EDI (commercial)** - Commercial customer must contact third party, which then contacts LG&E/KU for setting up EDI account.
- **Low-income portal** – Residential customers can request that a low-income agency have access to their accounts by providing personal identifiable information to the agencies for validation.
- **Green Button Data –** All customers have access to downloading their energy consumption data in a standard format that can be shared at will with external parties. The Green Button Data export does **not** contain personal identifiable information about the customer.

Data Access

AMS-enabled data

AMS provides more detailed consumption data



https://lge-ku.com/mymeter/additional-views

AMS-enabled data

Currently available

Total monthly consumption comparisons are displayed on customer bills, along with average daily use for the given month.

BILLING PERIOD AT-A-GLANCE

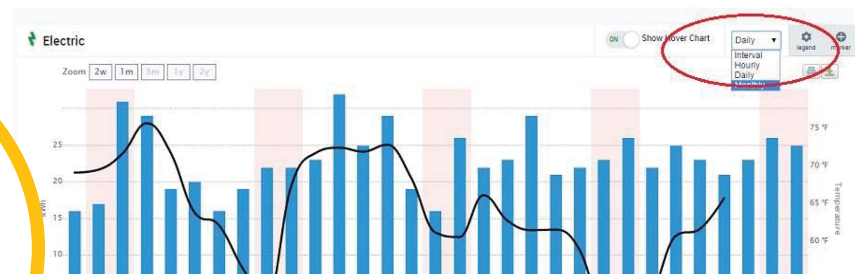
	THIS YEAR	LAST YEAR
Average Temperature	53°	49°
Number of Days Billed	29	29
Avg. Electric Charges per Day	$1.86	$2.08
Avg. Gas Charges per Day	$1.85	$2.10
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97

Granular data in varying time intervals

Energy usage

Added by AMS

MyMeter
Customers may choose to view information by 15-minute increments, day, week, month or year.

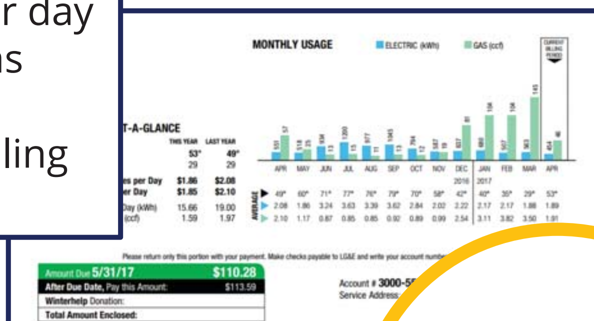


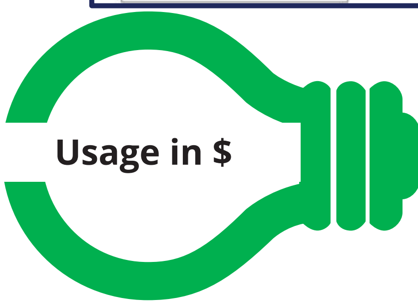
https://lge-ku.com/mymeter/additional-views

AMS-enabled data

Currently available

Customers can see monthly total bill, monthly total consumption charge, as well as the average charge per day in $, which is calculated as total monthly bill by the number of days in the billing month.





Energy usage

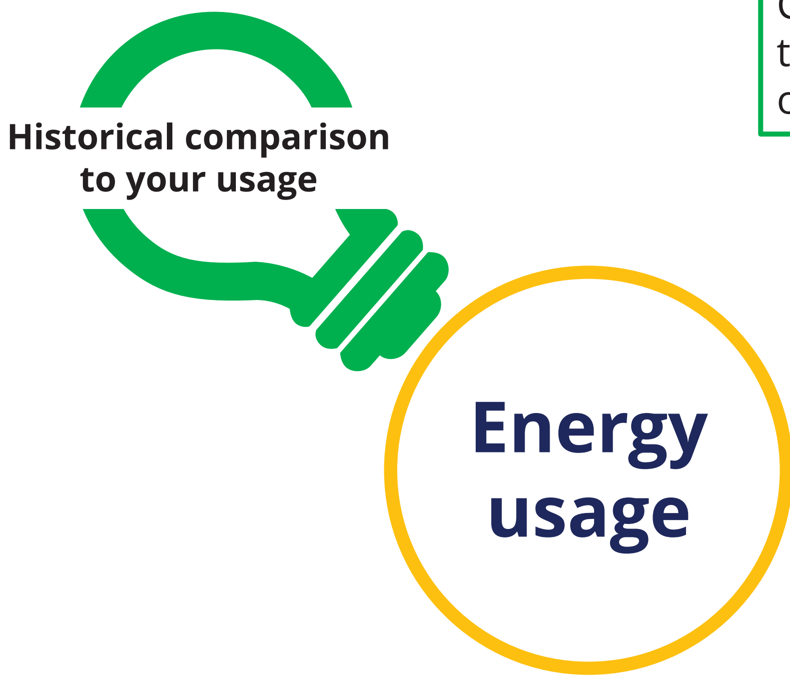
Added by AMS

Customers can view consumption data in **$ down to 15-minute intervals.** This does not equate to a customer's bill – it is the calculation of the energy usage multiplied by the rate in which the customer is enrolled.

https://lge-ku.com/mymeter/additional-views

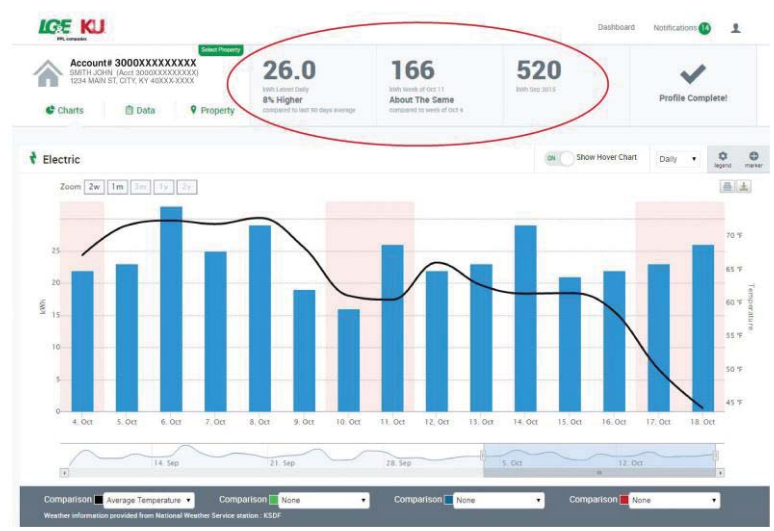
AMS-enabled data

No like comparison currently available...



Added by AMS

MyMeter
Customers will have the ability to compare their energy usage to previous time periods or specifically marked periods.



https://lge-ku.com/mymeter/additional-views

AMS-enabled data

Currently available

Customers can see monthly average temperature for their location on their bill.

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**53°**	**49°**
Number of Days Billed	29	29
Avg. Electric Charges per Day	**$1.86**	**$2.08**
Avg. Gas Charges per Day	**$1.85**	**$2.10**
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97

https://lge-ku.com/mymeter/additional-views

Added by AMS

Energy usage

Temperature data by interval

Customers will have the ability to view their energy usage with the average daily temperature superimposed on the charts.

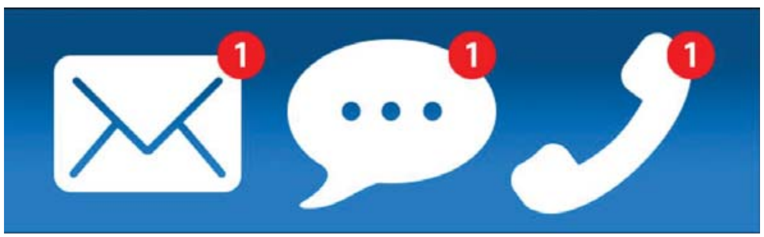
AMS-enabled data

Currently available

Customers can select when they want to be notified about their bills – when **bill is ready to view**, **five days before payment is due**, or **one day past the due date.**
They can be notified via **text**, **phone**, **email**, or any **combination** of the three.

Added by AMS

By setting threshold limits on their **energy consumption**, customers can request and receive a MyMeter notification when they have reached a desired threshold **(in kWh and / or $).** Notifications can be sent via **text** or **email,** and the frequency of notifications can be specified (daily, weekly, monthly)**.**



Energy usage

https://lge-ku.com/mymeter/additional-views

Channels for Accessing Data

Customers have multiple options for accessing their data

Personal channels

- Mobile (phones, tablets)
- Computers

- Access MyMeter portal via mobile-friendly web browser to view energy consumption data, either on a computer or on-the-go.
- Receive email notifications that can be viewed on computers or mobile on energy consumption.

Company channels

- Customer Call Center
- Customer Service center

- Call Customer Call Center for detailed information on energy consumption.
- Use laptop available at Customer Service Center to log into MyMeter and view energy consumption.
- Request that Customer Service Center representative set notification preferences for direct text / email notifications through mobile.

Community channels

- Libraries
- Community Centers

- Access MyMeter portal in community locations that provide internet access free of charge.

Additional support for internet and cellular access

There are also Federal and State programs designed to facilitate access to internet and cellular

Mobility Fund program: Allocates up to $4.53 billion over the next decade to advance 4G LTE service, with the majority of the funding going to rural areas that would not be served in the absence of government support.
Lifeline program: Directly subsidizes broadband and mobile access for low income families through its Lifeline program. After establishing eligibility, which is needs-based, a person can purchase phone or internet services at a discount.

Connect America Fund: Provides an additional $2 billion for rural fixed broadband over the next decade.
E-Rate funding program: Makes telecommunications and information services more affordable for schools and libraries across America.
KentuckyWired: Helps bring fast and reliable broadband access to underserved and unserved parts of Kentucky.

Third-Party Access

Low Income Portal

Overview of Low Income Portal

Who

- Low-income advocacy groups that have signed Confidentiality Agreements and adhere to all procedural requirements can obtain access to the portal

How

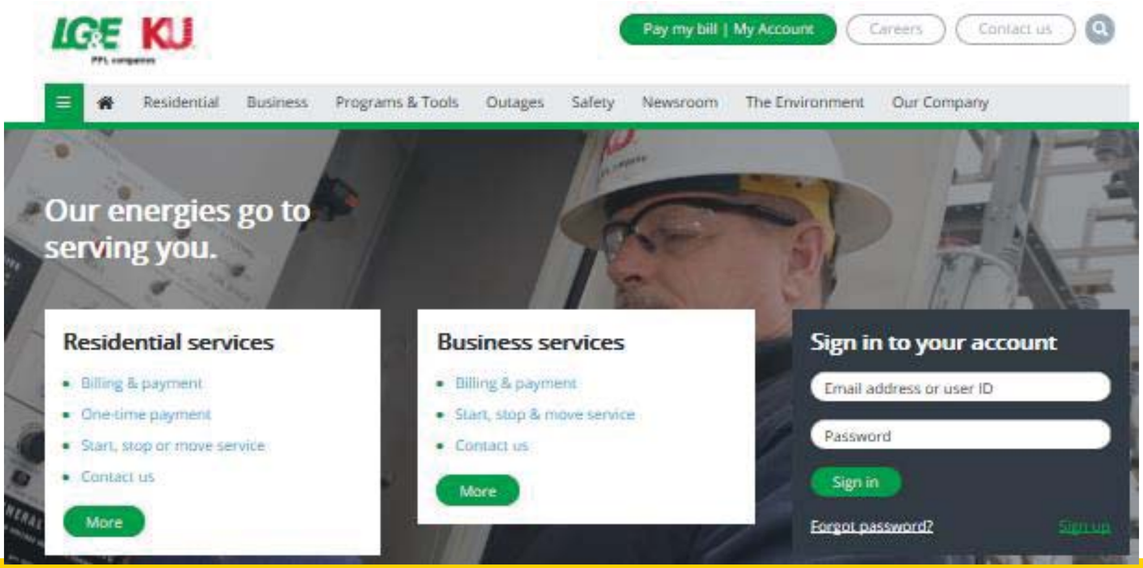
- Agency representatives will be assigned an ID and password. There is no limit to how many representatives can log on at one time.

What

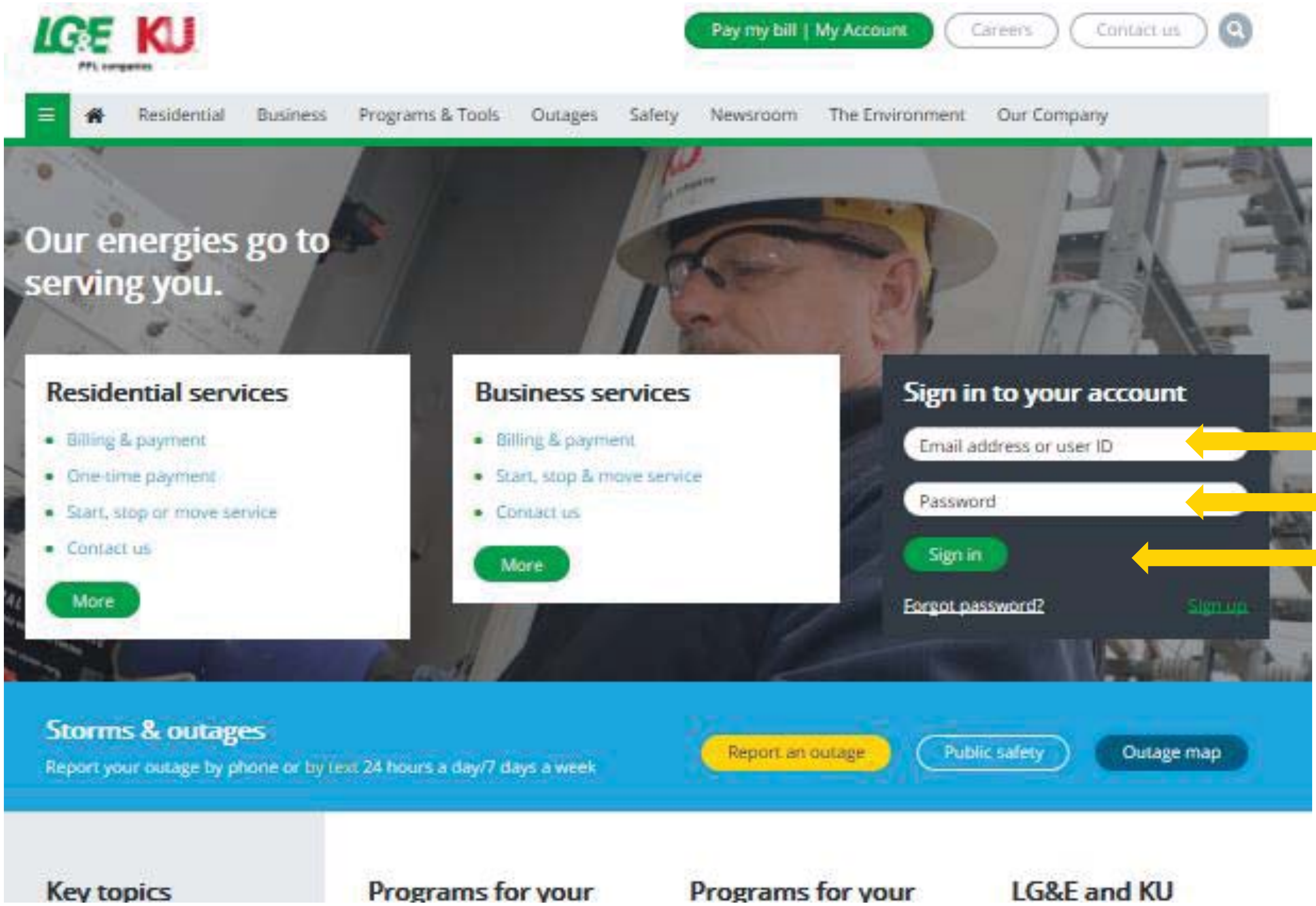
- Find how much your client owes to LG&E and KU
- View the customer’s gas and electric usage and bill amounts for the last 12 months
- View previous pledges and payments
- Enter a pledge

Why

To provide low-income agencies the tools to support their constituencies, facilitating the access to customer data and the ability to support their needs.



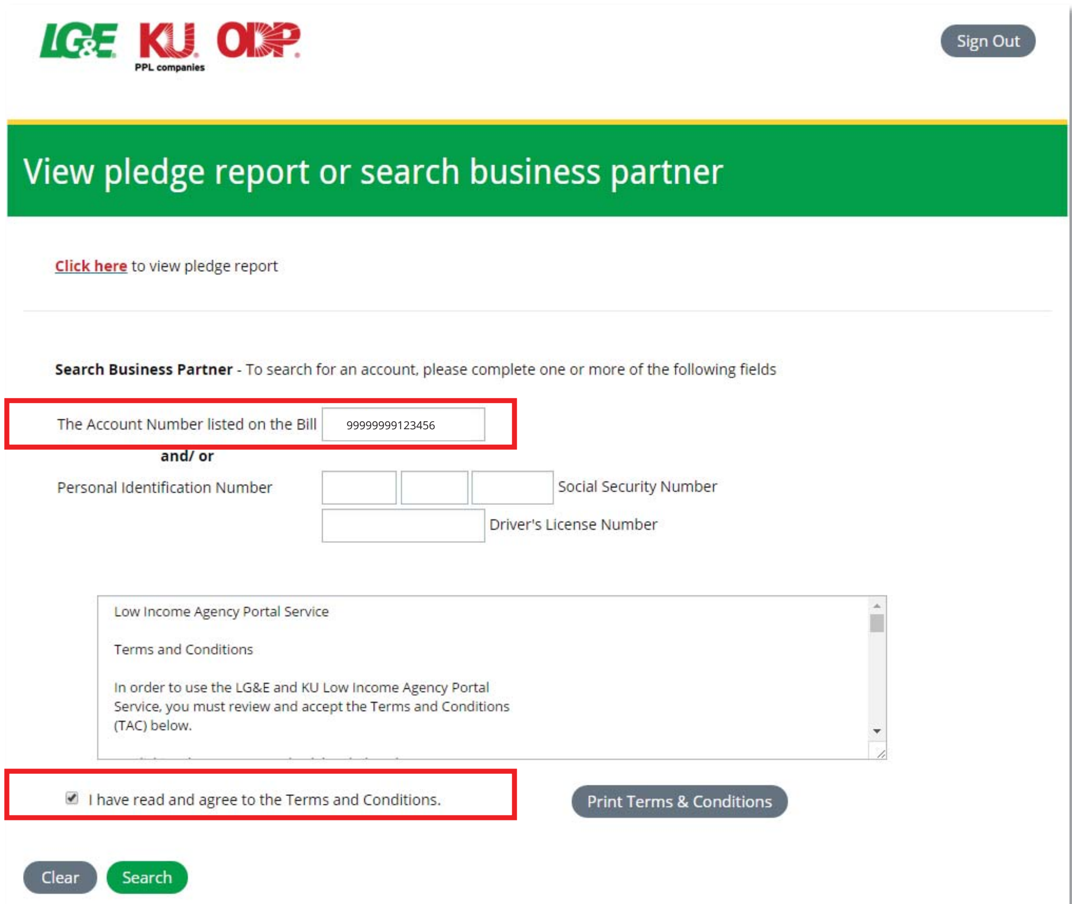
Home Screen



Type your Agency's User ID and Password

Click the ***Sign In*** button

Enter Account Number/Agree to Terms



View Customer's information

Sign Out

Pledge Entry

99999999123456 – JOHN DOE, 1234 Right Way, KY 40202, Jefferson

Current Balance:	$869.27	Last Hardship Reconnect:	00/00/0000
Payment Plan Balance:	$0.00	Budget Billing:	No
Past Due Balance:	$684.65	Late Payment Charge Waiver:	No
Delinquent Due Date:	08/22/2017	CFN Expiration Date:	00/00/0000
Delinquent Amount:	$684.65	Medical Expiration Date:	00/00/0000
Disconnect Amount:	$684.65	50% Pledge Expiration Date:	00/00/0000
Amt. to Prevent Disconnection:	$342.33	WeCare Date:	00/00/0000

Request WeCare

All services are currently connected.

Payment and Pledge Information

Date	Amount	Type	Pledge Id	Agency
07/25/2017	$308.00	Paymentus		
07/25/2017	$150.00	Paymentus		

More Payments

Previous

View Usage History

Displays 12 Months of Usage History

Sign Out

View Usage History

99999999123456 – JOHN DOE, 1234 Right Way, KY 40202, Jefferson

Electric consumption

Meter Reading Date	Consumption	Amount
08/03/2017	1671.0	$167.72
07/06/2017	1597.0	$156.74
06/06/2017	1591.0	$155.06
05/02/2017	1434.0	$141.19
04/04/2017	1927.0	$184.86
03/02/2017	1854.0	$180.69
02/01/2017	2666.0	$252.75
01/03/2017	3112.0	$283.07
12/01/2016	2018.0	$189.38
10/31/2016	1894.0	$177.50
09/30/2016	1787.0	$169.25
09/01/2016	1944.0	$186.74
08/02/2016	1876.0	$179.69

Export Data

Gas consumption

Meter Reading Date	Consumption	Amount

Previous

BREAK

Solutioning Exercise

Data Access

Generating Solutions for Stakeholders

What?

- Gathering your input regarding potential solutions how to make the most out of AMS
- Thinking about it from the perspective of customer personas – in their shoes

How?

- For each session, your table will be assigned a customer persona
- Put yourself in their shoes based and address a series of questions for the associated topic
- Capture your ideas on post-it notes (color-coded by persona)
- Represent your customer persona in the large group debrief

Representative Customer Personas

Low Income	Resi-dential	Care-giver	Non-Resi-dential	Seniors
• Receive assistance • Do not request assistance	• Renters • Environmentalist • Young families (time / capacity) • Empty nesters / no children	• To elderly • To children (e.g. students) • To others needing support (disabilities)	• Schools • Metro / Cities / Public Authorities • Small commercial	• Tech-savvy • Technophobe • Snowbirds

Breakout Solutioning Activity: Data Access

At your tables…

- Put yourself in the shoes of the persona assigned to your group
- Generate response to the following questions:
  1. What tools / channels (existing or new) that LG&E/KU can provide do you need to overcome today's challenges?
  2. What other mechanisms would you like in the future for accessing the data? Do you have examples of data access from other industries?
  3. Who needs access to your data that does not have it today?
  4. Where would you go to access information? (i.e. library, business centers, kiosks at grocery store, etc.).

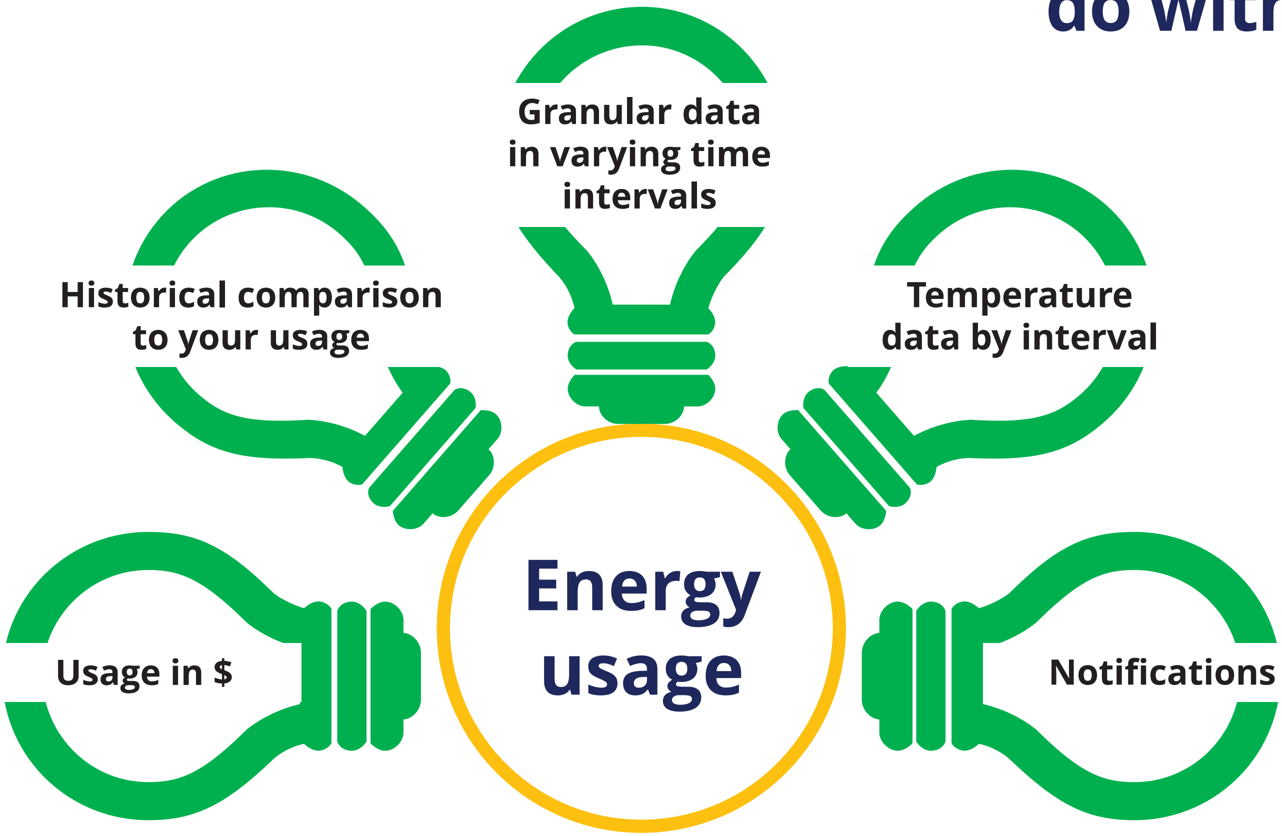
20 min discussion
10 min debrief

Data Use & Empowerment

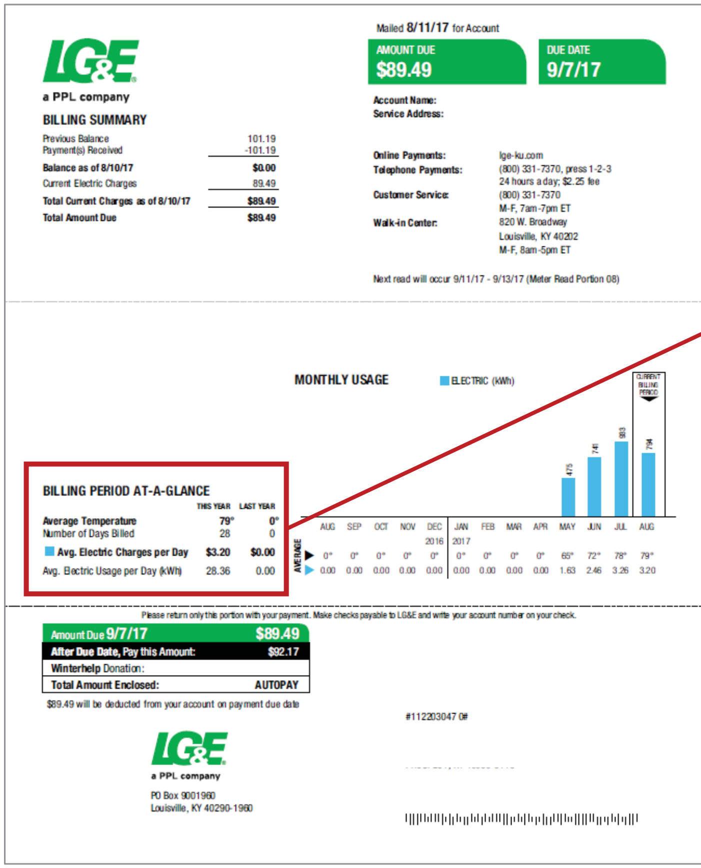
AMS-enabled data

Remember the data we now have access to…

Now, what can we do with it?



Powering Informed Decisions



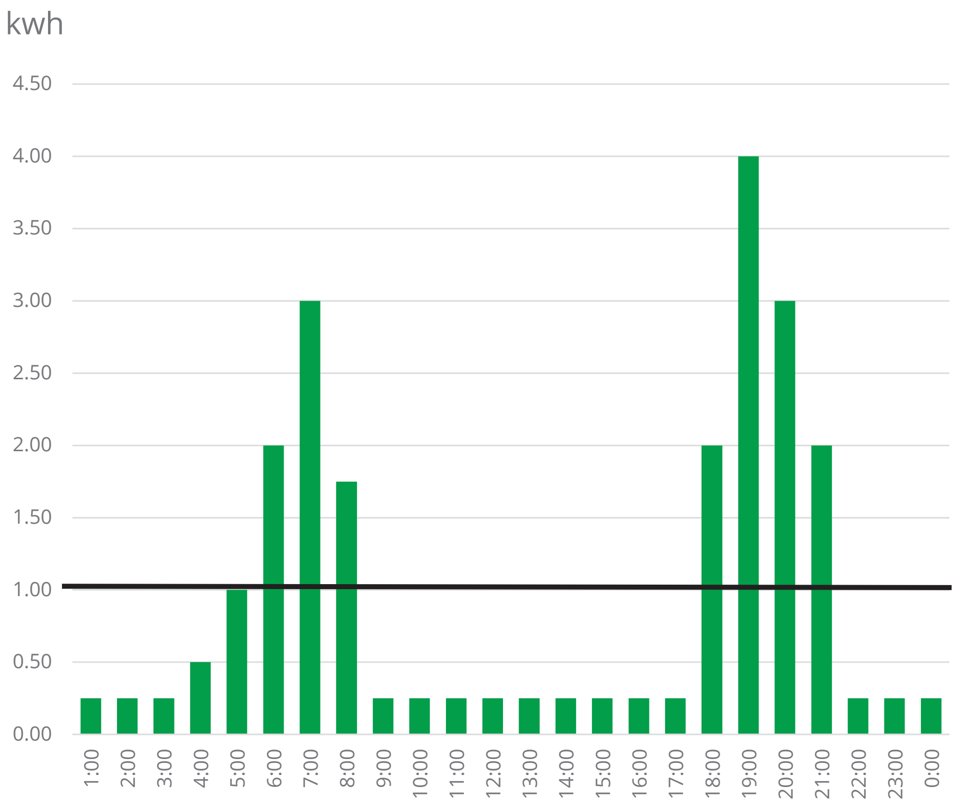
BILLING PERIOD AT-A-GLANCE

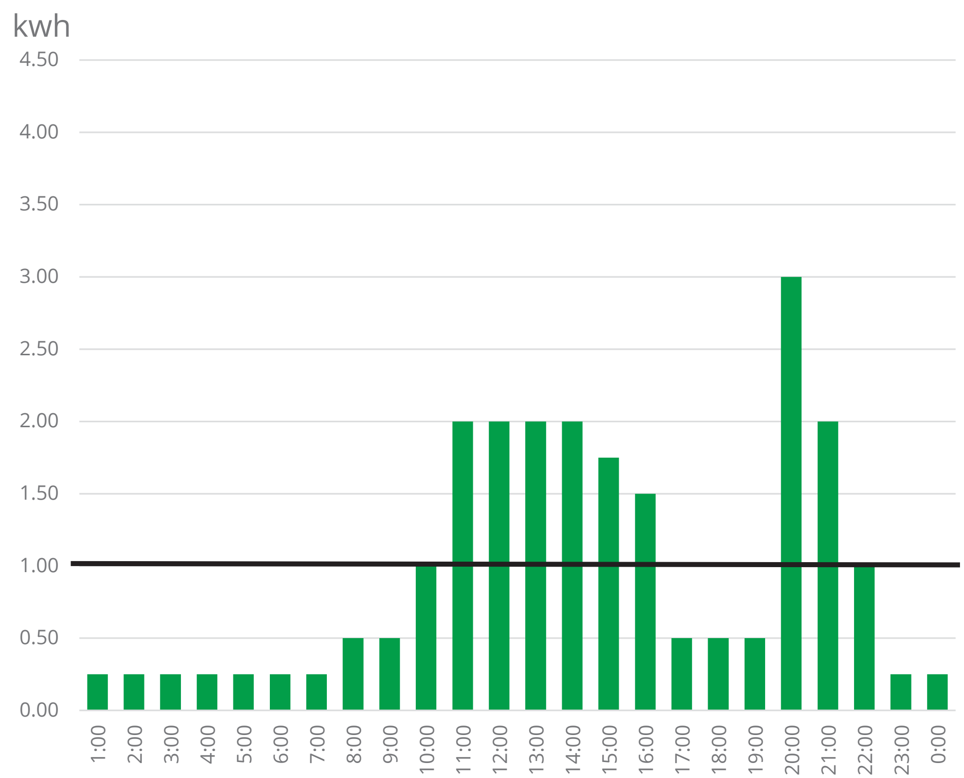
	THIS YEAR	LAST YEAR
Average Temperature	**79°**	**0°**
Number of Days Billed	28	0
Avg. Electric Charges per Day	**$3.20**	**$0.00**
Avg. Electric Usage per Day (kWh)	28.36	0.00

"Notify me when my daily usage reaches 20 kWh (~$3.00 for the day)"

Data to empower decisions

Daily consumption is the same but patterns are different



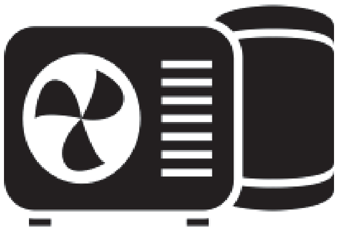


LG&E KU
PPL companies

Data empowerment examples

Setup a **notification** for a preset daily energy usage to **manage my monthly budget**.

Checked my usage online to **verify** the adjustment to my thermostat was really **reducing my energy consumption.**



Checked my energy usage while I was **on vacation** and noticed increase. **Identified a problem** with the HVAC system.

Accessed my **college student's** energy patterns to ensure they were **reducing their energy consumption while at class.**

Solutioning Exercise

Data Use & Empowerment

Breakout Solutioning Activity: Data Empowerment

At your tables…

- Put yourself in the shoes of the persona assigned to your group
- Generate response to the following questions:

1. Based on the data available, what changes to your energy use would you make?
2. What additional data or tools would you need to make decisions?
3. What benefits would you expect to achieve?

20 min discussion
10 min debrief

LUNCH

Consumer Education

Customer Education Objectives

Creating awareness of AMS program & what is in it for the customer

Facilitating customer through installation process / timing

Developing understanding of how to use new information and tools to achieve potential benefits

Multi-Channel
Surround Sound

Targeted Outreach

Customer Education: Installation [1]

6 weeks prior	4 weeks prior	2 weeks prior	Installation Week
Stakeholder Communications – AMS Collaborative – KYPSC – Local Officials – Low Income Agencies – Medical Alerts – Special Needs – Major Accounts – Media	**Customer Notification**	**Customer Notification**	**Customer Notification** **Meter Installed**

Customer Experience Surveys

LG&E/KU Walk-in Center Communications — *Launch* — *Support Meter Installations* — *Customer Education Series Begins*

[1] *Illustrative view*

Example: LG&E Gas Riser Project

Customer Notification

LG&E
a PPL company

Louisville Gas and Electric Company
Customer Service
820 West Broadway
PO Box 32010
Louisville, KY 40232
www.lge-ku.com

T 502-589-1444
Toll-Free 1-800-331-7370

March 2013

A Change to Your Natural Gas Service

Dear Valued Customer:

On January 1, 2013, LG&E assumed responsibility for installing, maintainin repairing and replacing gas service piping for all our natural gas customers, where previously this was the customer's responsibility. The gas service piping is the portion of the gas service line that extends from your property line or the utility easement to the LG&E gas meters. (See the diagram on the back of this letter for details.)

As a result of this new responsibility, we began a five-year inspection program in April 2013. Our LG&E employees and contractor crews will inspect and, where necessary, repair or replace the piping and riser components of the service line. Over time, the industry has seen deterioration in certain types of service risers throughout the U.S., resulting in gas leaks. LG&E has seen a small percentage of these leaks on customers' piping on its system.

If any deficiencies are noted during our inspections, LG&E will make any needed repairs or upgrades, including necessary replacements of service risers. In the meantime, as always we urge you to pay attention to signs of potential gas leaks and report those to us immediately. Please visit our website at lge-ku.com/rac.lge.gas_safety.asp to review our Family Guide to Gas Safety for important information about natural gas safety.

You do not need to take any action regarding our ongoing inspection program at this time. We will provide more detailed information to you when the inspections are ready to begin in your neighborhood.

We also want to take this opportunity to advise you of a few additional points now that LG&E has responsibility for installing, maintaining, repairing and replacing gas service piping:

- LG&E will install (and be responsible for) **new** gas service piping up to and including the gas meter. See the diagram on the back of this letter to see the piping customers will continue to own and be responsible for maintaining.

A Change to Your Natural Gas Service
March 2013

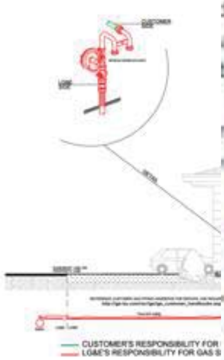
Page – 2 –

- LG&E will repair or replace existing gas service pipin meter loop if a leak occurs. This means customers will to hire a plumber to make the repairs or replace the ser
- LG&E will relocate existing gas service piping at the c request. Before performing the work, LG&E will prov of any charges the customer will be required to pay.

Thank you for taking the time to read this important informati

Sincerely,

Paul Stratman
Manager, Gas Construction



Q. What if LG&E finds a leak on my natural gas "house line"?

A. LG&E will always perform a safety check on the "house lines" after the riser replacement and before the natural gas appliances are relit. If a leak is detected on your "house lines", we will turn off your natural gas and let you know what steps you need to take to have the leak repaired. LG&E cannot make the necessary repairs on your "house lines". Maintenance and repairs of the "house lines" are the customer's responsibility. After you have made the repairs, call LG&E and we will send a crew as quickly as possible to perform the safety check to confirm the "house lines" are no longer leaking and then turn on your natural gas service.

Q. Will I need to contact LG&E to schedule an appointment to have the work done on my property?

A. No appointments are needed from April through November. Our crews will leave a notice on your door letting you know we are in the area doing inspection work. During the colder weather months (December through March), we will contact you to schedule an appointment to perform the work if an interruption to your gas service is necessary. If you receive a notice asking you to contact us to schedule an appointment, please call us at the number provided to schedule the work for your home or business.

Q. Will I have to be home when the work is performed?

A. No. You will not need to be home during the actual inspection and construction work. However, if we turn off your gas service, someone age 18 or older must be present to allow our crews to access your home or business to restore your service and relight your natural gas appliances.

Q. Will traffic on my street be blocked?

A. Not likely. Most of the work will be performed near your natural gas meter. As a result, we will not have to block the street or impede traffic flow. If there is a time, however, when our trucks or heavy equipment need to block the street, our crews will be onsite and can move to allow you to pass or access your driveway. Just let us know what you need.

Q. Will my street be torn up?

A. Not likely. Because most of the work will be performed near your natural gas meter, it is not likely we will need to do any work on the street.

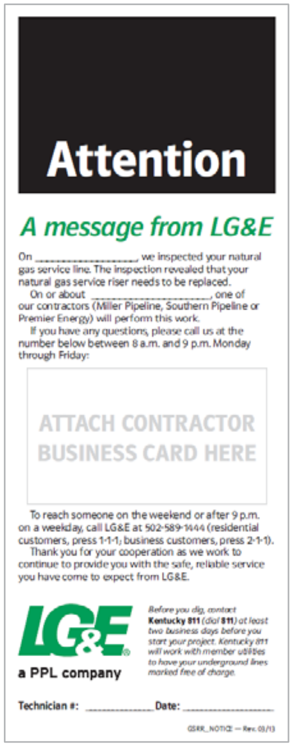
Q. Will my yard and/or landscaping be affected?

A. Possibly. Our crews work in as small an area as possible and try to minimize any disruption to your yard or landscaping. The work will primarily affect the area around your natural gas meter, but some small excavation work will be required if we have

Example: LG&E Gas Riser Project

Door Hangers

Winter



Attention

A message from LG&E

On ____________________, we inspected your natural gas service line. The inspection revealed that your natural gas service riser needs to be replaced.

On or about ________________________, one of our contractors (Miller Pipeline, Southern Pipeline or Premier Energy) will perform this work.

If you have any questions, please call us at the number below between 8 a.m. and 9 p.m. Monday through Friday:

ATTACH CONTRACTOR BUSINESS CARD HERE

To reach someone on the weekend or after 9 p.m. on a weekday, call LG&E at 502-589-1444 (residential customers, press 1-1-1; business customers, press 2-1-1).

Thank you for your cooperation as we work to continue to provide you with the safe, reliable service you have come to expect from LG&E.

LG&E a PPL company

Before you dig, contact **Kentucky 811** *(dial* **811***) at least two business days before you start your project. Kentucky 811 will work with member utilities to have your underground lines marked free of charge.*

Technician #: ______________ Date: __________________

GSRR_NOTICE — Rev. 03/13

Summer

Important!

We recently inspected and performed some work on your natural gas service line. This work requires us to check the gas lines inside your home/business prior to relighting your natural gas appliances.

Our representative stopped by to discuss this with you, but no one answered the door at the time. Please contact our representative at the number below to schedule a time when someone age 18 or older will be there to let us in and complete the check.

ATTACH CONTRACTOR BUSINESS CARD HERE

If we do not hear from you by __________, it may be necessary for us to turn off your natural gas to do this. Your natural gas service will be off until we can come inside and check the lines and relight the appliances. We hope to hear from you soon!

Thank you for your cooperation as we work to continue to provide you with the safe, reliable service you have come to expect from LG&E.

LG&E a PPL company

Before you dig, contact **Kentucky 811** *(dial* **811***) at least two business days before you start your project. Kentucky 811 will work with member utilities to have your underground lines marked free of charge.*

Technician #: ______________ Date: __________________

GSRR_CHECK — Rev. 03/13

Completed

Attention

An important message from LG&E

On ____________________, we inspected your natural gas service line. Our inspection indicated no work is required on your gas service, and you do not need to take any action at this time.

If you have any questions about the inspection, please call us at the number below between 8 a.m. and 9 p.m. Monday through Friday:

ATTACH CONTRACTOR BUSINESS CARD HERE

If you have questions or need to speak with someone after 9 p.m. or on weekends, please contact LG&E at 502-589-1444 (residential customers press 1-1-1; business customers press 2-1-1).

Thank you for allowing us to continue to provide you with the safe and reliable natural gas service you have come to expect from us.

LG&E a PPL company

Before you dig, contact **Kentucky 811** *(dial* **811***) at least two business days before you start your project. Kentucky 811 will work with member utilities to have your underground lines marked free of charge.*

Technician #: ______________ Date: __________________

GSRR_FIN — Rev. 03/13

How did we do?

Telephone Survey

Customer Education: General Awareness & Energy Literacy

Multi-Channel Approach

Awareness: When you're interacting across multiple channels, customers recognize the messages easier and awareness increases.

Engagement: Being available via a customer's chosen channel directly results in higher levels of engagement.

Change: More opportunities to engage across channels means customers will participate more and begin to adopt new behaviors.

Measure: Measuring customer awareness and engagement provides the ability to target messaging and increase participation.

Example: Energy Efficiency Programs

Multi-Channel Approach

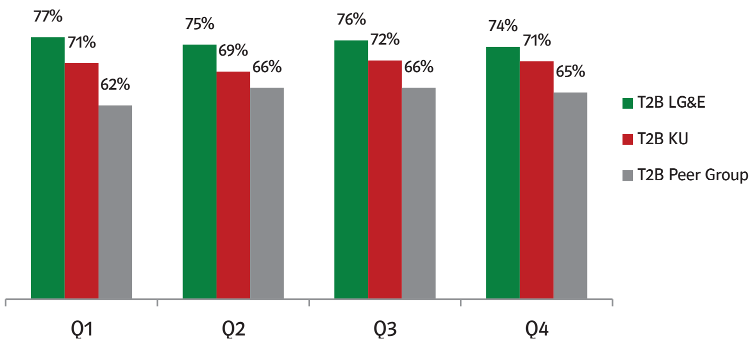
Awareness: When you're interacting across multiple channels, customers recognize the messages easier and awareness increases.

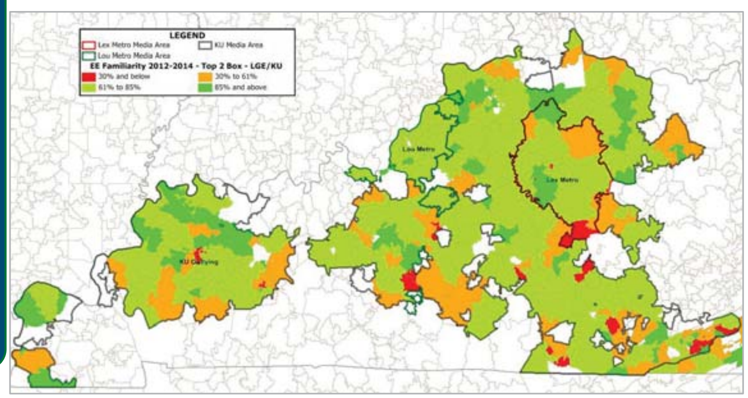
1. Measure effectiveness of mass media campaigns.
2. Benchmark against a peer set of utilities.
3. Map awareness by media market.
4. Identify low awareness areas.

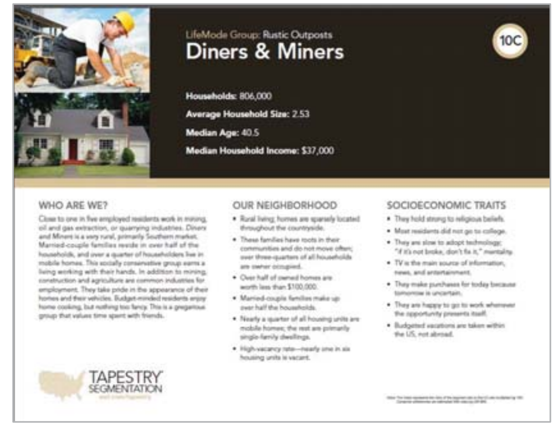
Engagement: Being available via a customer's chosen channel directly results in higher levels of engagement.

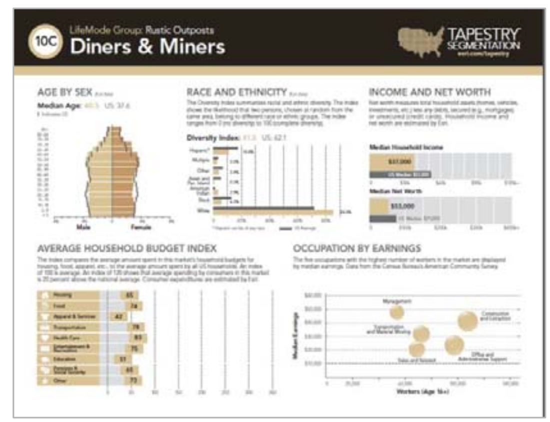
1. Identify characteristics of targeted locations.
2. Develop and launch targeted campaign.

Familiarity with Energy Efficiency Programs









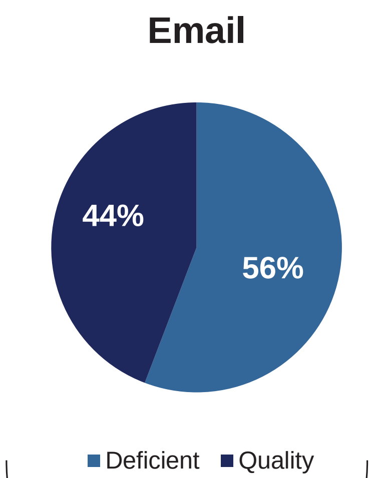
Example: Energy Efficiency Programs

Multi-Channel Approach

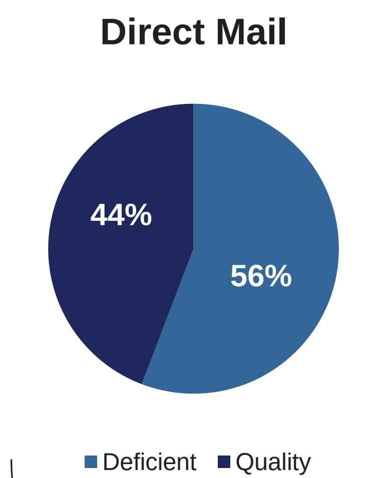
Change: More opportunities to engage across channels means customers will participate more and begin to adopt new behaviors.

Measure: Measuring customer awareness and engagement provides the ability to target messaging and increase participation.

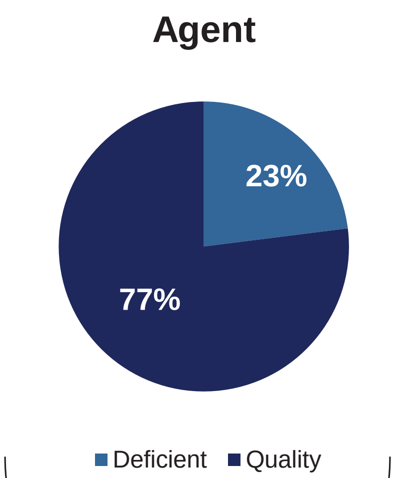
1. Measure participation via marketing channel.
2. Identify issues related to unsuccessful leads.
3. Refine processes and messaging.



Deficient enrollments primarily driven by **renters failing to return Landlord Consent form**.



Deficient enrollments primarily driven by **renters failing to return Landlord Consent form**.



Deficient enrollments primarily driven by **equipment condition or no outside disconnect.**

Deficient = Ineligible, Cancelled, Landlord Consent or Contact Attempted.
Quality = Completed

Solutioning Exercise

Customer Education

Breakout Solutioning Activity: Education

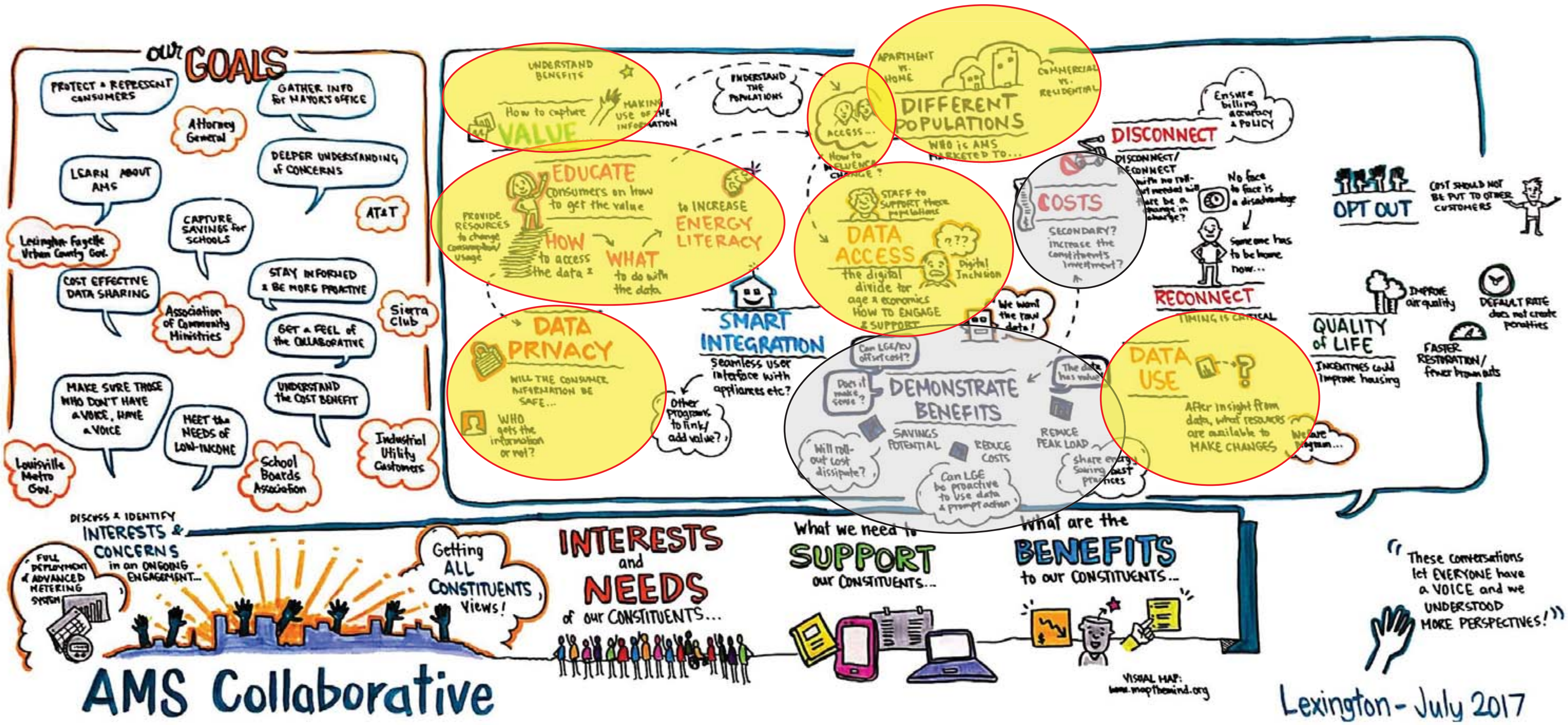
At your tables…

- Put yourself in the shoes of the persona assigned to your group
- Generate response to the following questions:

1. What channels are most effective for you to receive information and educational information?
2. What approaches would work well for you to learn more about how to manage your energy?
3. What topics are most important for you to learn more about?

20 min discussion
10 min debrief

AMS Collaborative Session #1 Visual Map



AMS Collaborative Future Sessions

Order	Theme	Summary Description	Estimated Duration
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	½ Day
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	½ Day
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	½ Day
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	½ Day
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	½ Day
7	**Cost / Benefit Recap**	• Review of business case with adjustments	½ Day

SCHEDULE

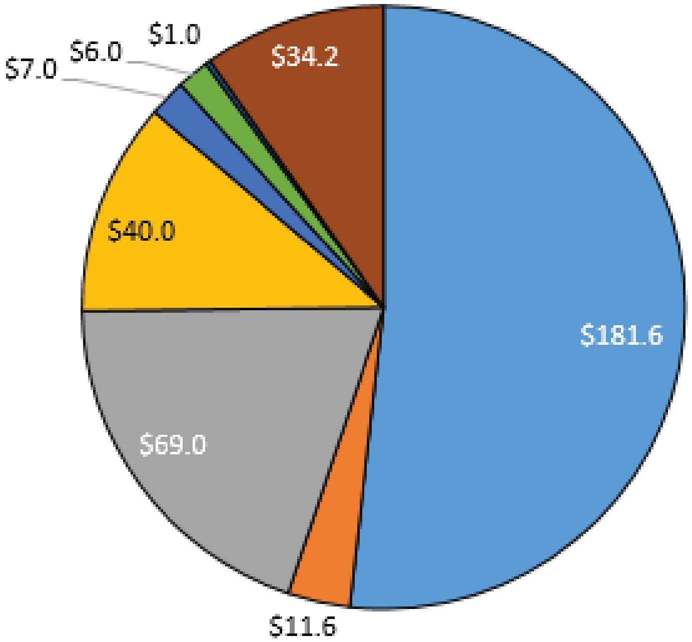
AUG 22	SEP 20	OCT 17	NOV 8 …
Costs / Benefits - Baseline	**Data Privacy / Sharing & Data Empowerment & Education**	**Opt-out, & Remote Disconnect / Reconnect & New Services**	**Cost / Benefit - Recap**

Kentucky Chamber of Commerce

BREAK

Business Case Follow-up

Gross AMS implementation costs are ~$350 Million for 2016 – 2021

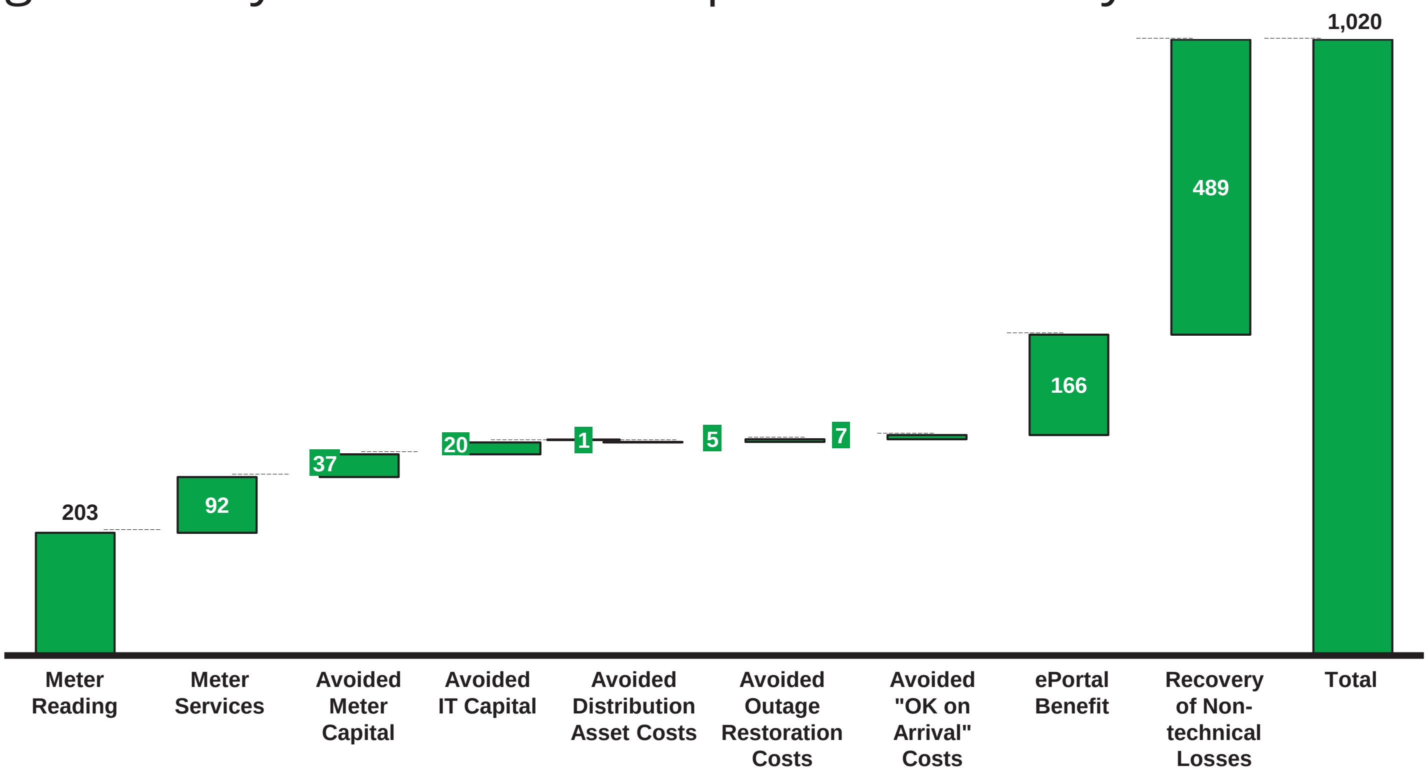


Project Costs 2016 – 2021 $ Millions

Category	Capex	OpEx	Total
Meters	167.0	14.6	**181.6**
Network & Network Management	10.4	1.2	**11.6**
Information Technology	56.7	12.3	**69.0**
Systems Integration	40.0	-	**40.0**
Program Management	5.1	1.9	**7.0**
Communications	6.0	-	**6.0**
Change Management	1.0	-	**1.0**
Contingency	34.2	-	**34.2**
Total	**320.4**	**30.0**	**350.4**

AMS Benefits Summary

- Total savings of nearly $1020 Million are possible over 20 years



Reference: Page 67, Case 2016-00370 10_-_KU_Testimony_and Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf and Case 2016-00371 10_-_LGE_Testimony_and_Exhibits_-_Malloy_to Spanos_-_FINAL.pdf.

THANK YOU

AMS Collaborative
September 20 Session Summary

AMS Collaborative Session #3 – Logistics

Tuesday, September 20, 2017
9:00 AM – 4:00 PM ET
Kentucky Chamber of Commerce

Collaborative Objectives:

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests and questions

Session #3 Objectives:

- Review current policies and processes on privacy
- Discuss needs of constituency for data access
- Identify how users might be empowered with data and what steps are needed
- Seek to understand educational needs for users
- Discuss any open business case questions

PARTICIPANTS

Participant	Organization
James Bush	LFUCG
Kent Chandler	OAG
Marlon Cummings	Association of Community Ministries
Richard Dugas	LFUCG
Cathy Hinko	MHC
Lisa Kilkelly	Association of Community Ministries
Chris Seidt	LMG
Melissa Tibbs	CAC
Ron Willhite	KSBA
Barry Zalph	Sierra Club
David Huff Wendy Wagoner Tim Melton Rick Lovekamp Allyson Sturgeon Lora Aria Cheryl Williams Joni Votaw	LG&E / KU
Jamie Hart Phyllis Goodson	Accenture
Julie Gieseke	Accenture / Map the Mind

AGENDA

Topic	Time	Host
Safety Moment, Agenda, Session 2 Review, Framework of Session 3, and Introductions	9:00 AM	Phyllis Goodson
Data Security & Privacy	9:30 AM	David Huff
Data Access	10:00 AM	David Huff
Break	10:30 AM	
Data Access Exercises	10:45 AM	Phyllis Goodson, Jamie Hart
Data Use and Empowerment	11:30 AM	Wendy Wagoner
Data Use and Empowerment Exercise	12:00 PM	Phyllis Goodson, Jamie Hart
Lunch	12:30 PM	
Education	1:00 PM	Wendy Wagoner
Education Exercises	1:30 PM	Phyllis Goodson, Jamie Hart
Recap Session 3 and next steps	2:00 PM	Phyllis Goodson
Break	2:15 PM	
Discuss any remaining business case questions	2:30 PM	David Huff

Personas

Exploring AMS from different perspectives

Data Access

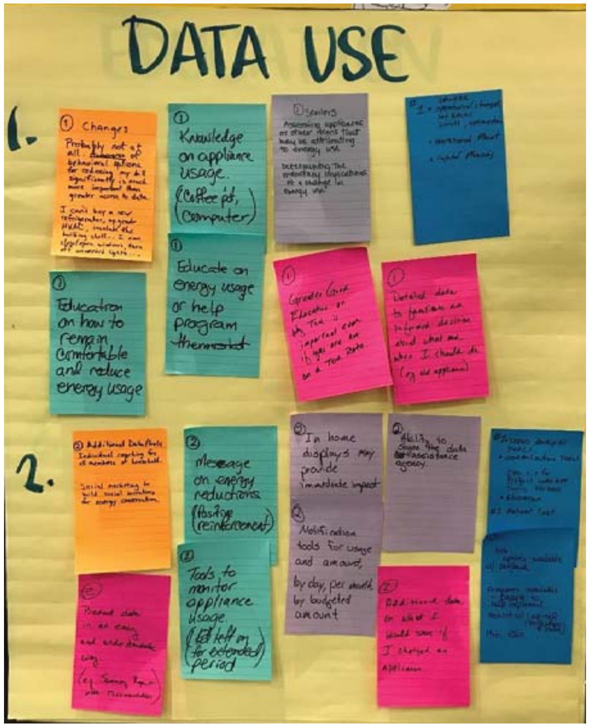
1. What tools / channels (existing or new) that LG&E/KU can provide do you need to overcome today's challenges?
2. What other mechanisms would you like in the future for accessing the data? Do you have examples of data access from other industries?
3. Who needs access to your data that does not have it today?
4. Where would you go to access information? (i.e. library, business centers, kiosks at grocery store, etc.).

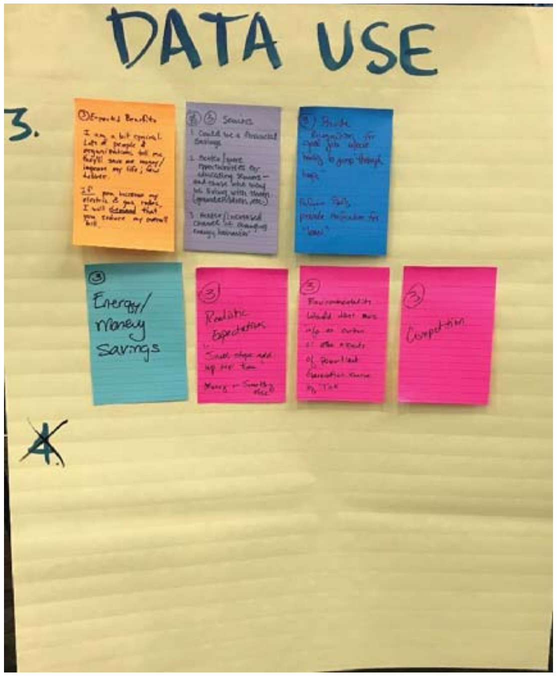
Data Use

1. Based on the data available, what changes to your energy use would you make?

2. What additional data or tools would you need to make decisions?

3. What benefits would you expect to achieve?



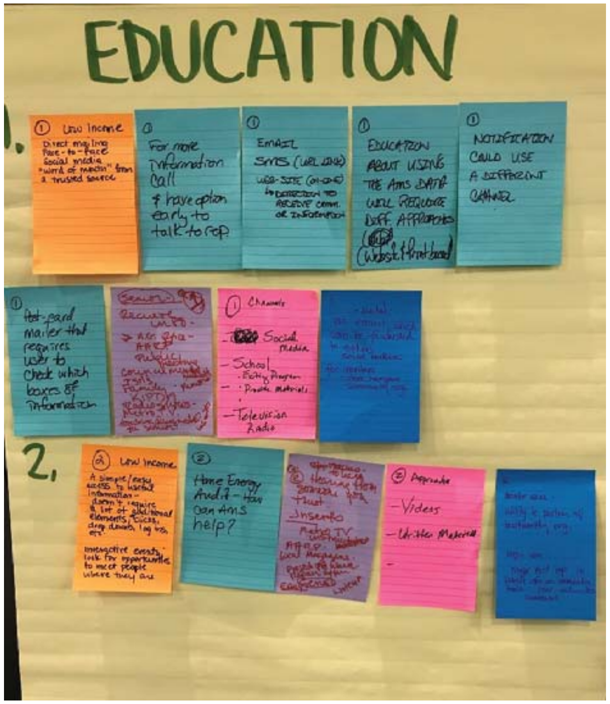


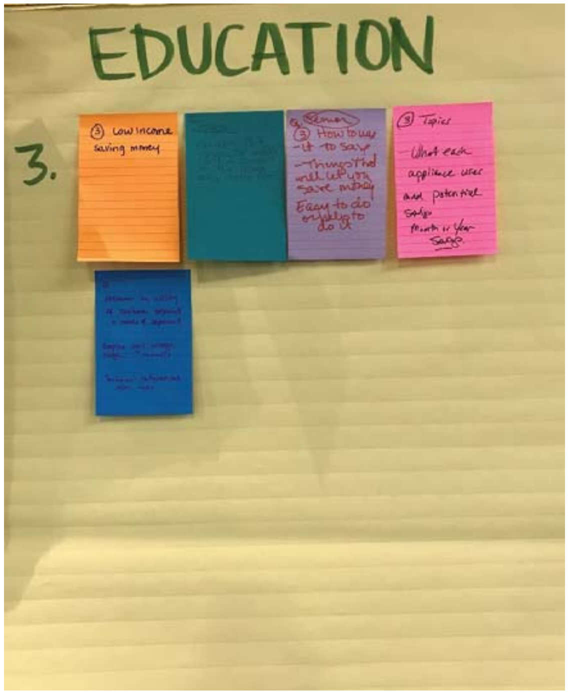
Education

1. What channels are most effective for you to receive information and educational information?

2. What approaches would work well for you to learn more about how to manage your energy?

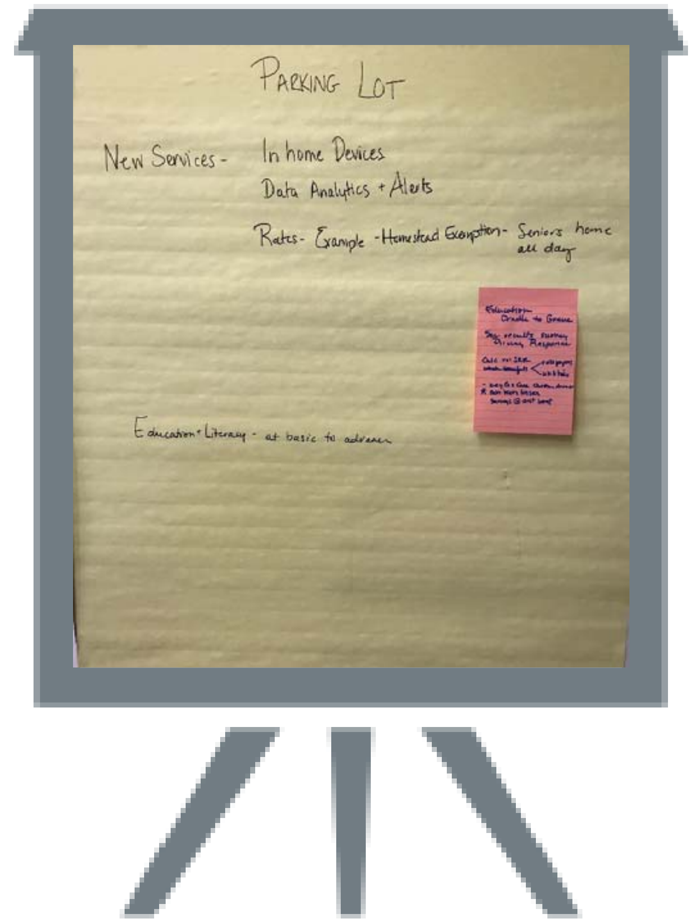
3. What topics are most important for you to learn more about?





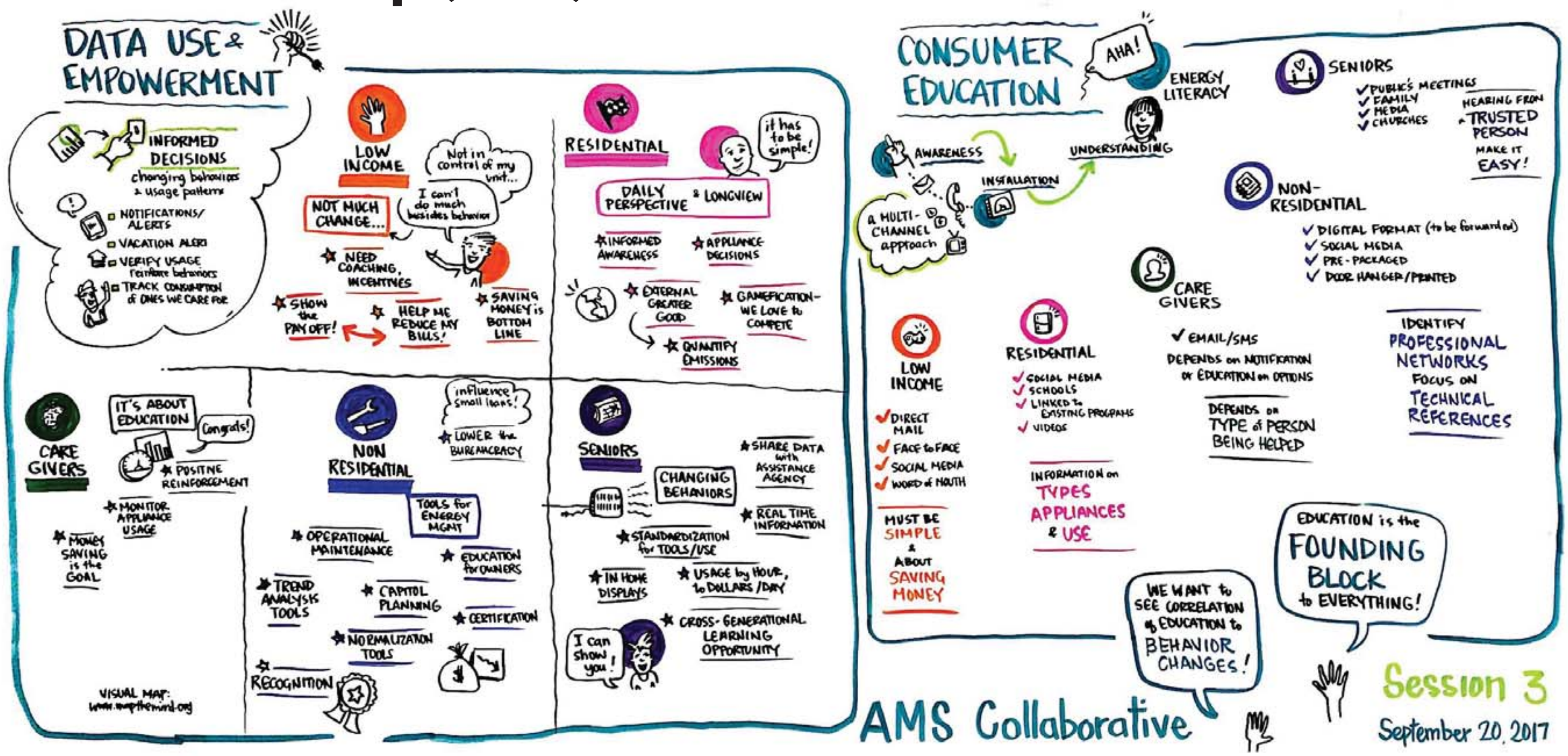
Parking lot

- Discuss under new services
  - In home devices
  - Data analytics and alerts
  - Rates – Example homestead exemption for seniors at home
- Education
  - Cradle to grave and how this transitions to benefits
- Calculation of IRR for benefits
  - Rate payers
  - Utilities
- Looking for more detail on non-technical losses – public studies



AMS Collaborative
Session #3 Visual Map

AMS Collaborative
Session #3 Visual Map (con't)



AMS Collaborative
Upcoming Session Dates

FUTURE MEETINGS

- Meetings to be held in Frankfort, KY if possible
- Meeting times will adjust to 9:00 a.m. to 4:00 p.m. to allow for all materials to be covered and provide ample time for discussion and questions

- Next Meeting:

  October 17, 2017, 9:00 a.m. @

  Kentucky Chamber of Commerce

OCT 17 | **NOV 8** | **...**

Opt Out
&
Remote Disconnect / Reconnect
&
New Services

Cost / Benefit - Recap

AMS Collaborative
Session 4 - October 17, 2017

PPL companies

Safety Moment

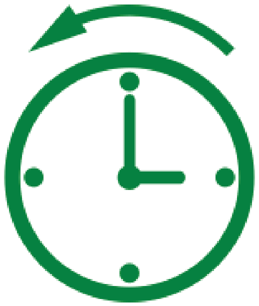
EXITS and EVACUATION ROUTES

- Exits
  - Main entrance and directly across on opposite end of hall
  - Through boardroom to outside door

- If evacuation is required
  - Go to the far end of the parking lot across from the main entrance of the building

- Restrooms
  - Down the hall

Fall Safety Reminders



Daylight Saving Time ends the first Sunday in November, which is a good trigger for a few safety reminders:

1. Be aware that it will get darker even earlier – keep an eye out for pedestrians
2. Take the opportunity to check the batteries in your smoke alarms and carbon monoxide detectors
3. Check your fire extinguishers
4. Refresh and rehearse your household emergency action plan

Agenda – Collaborative

Topic	Time	Host
Safety Moment, Agenda, Session 3 Review, and Framework of Session 4	9:00 AM	Phyllis Goodson
Opt-out	9:30 AM	Wendy Wagoner
Opt-out Discussion	10:00 AM	Facilitated
Break	10:30 AM	
Remote Service Switch	10:45 AM	Shannon Montgomery
Remote Service Switch Discussion	11:15 AM	Facilitated
Lunch	12:00 PM	
New Services Discussion	12:30 PM	Facilitated
Break	2:00 PM	
Collaborative Journey	2:15 PM	David Huff
Session 4 Recap and upcoming Session 5	2:45 PM	David Huff

AMS Collaborative Objectives

OVERALL

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests

TODAY

- Discuss options for customer opt-out of AMS
- Review current policies and processes on service disconnection today
- Discuss needs and solutions of customers and advocacy groups that encounter service interruptions for non-payment
- Identify new services that could be enabled through AMS and AMS provided data

AMS Collaborative Session 3 Review

Data Access

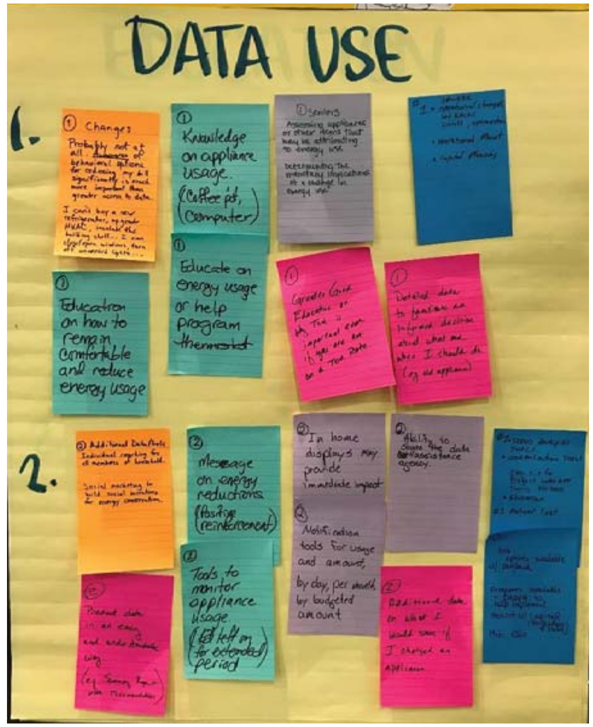
1. What tools / channels (existing or new) that LG&E/KU can provide do you need to overcome today's challenges?
2. What other mechanisms would you like in the future for accessing the data? Do you have examples of data access from other industries?
3. Who needs access to your data that does not have it today?
4. Where would you go to access information? (i.e. library, business centers, kiosks at grocery store, etc.).

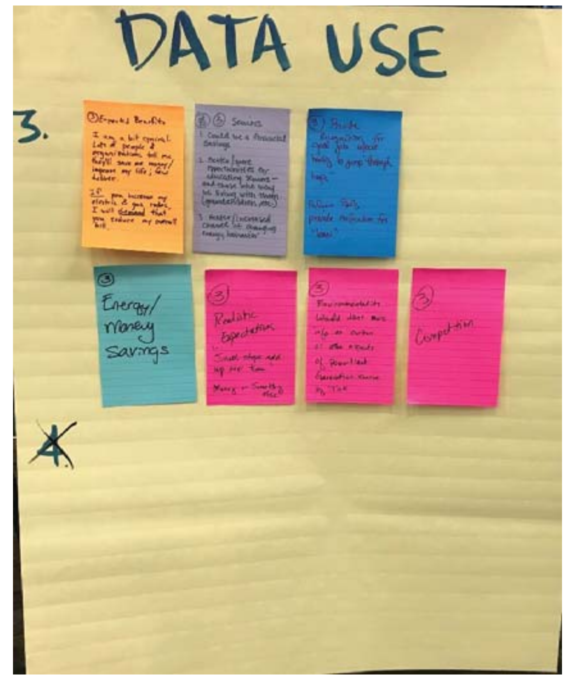
Data Use

1. Based on the data available, what changes to your energy use would you make?

2. What additional data or tools would you need to make decisions?

3. What benefits would you expect to achieve?





Education

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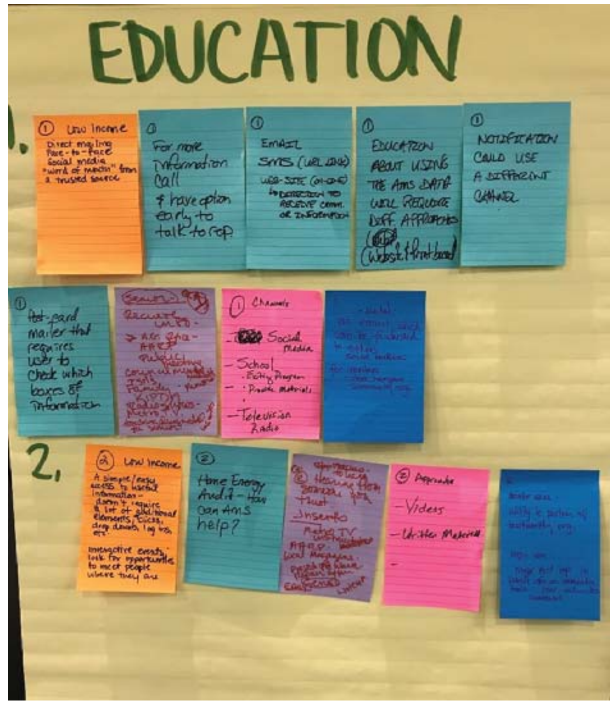
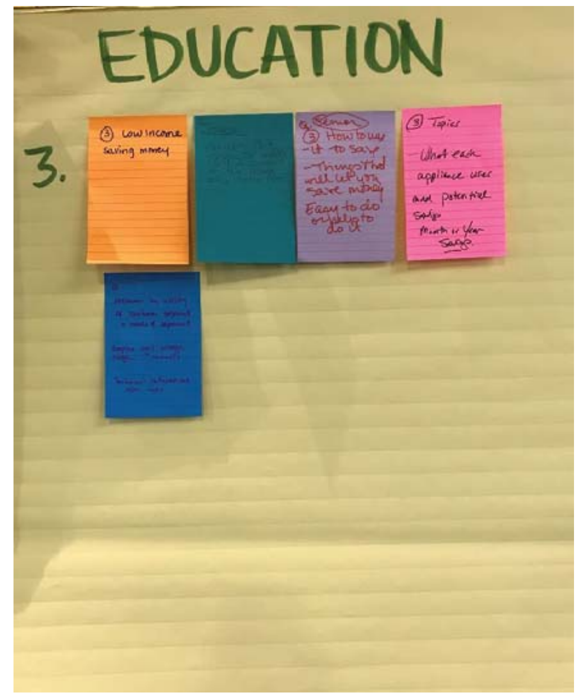
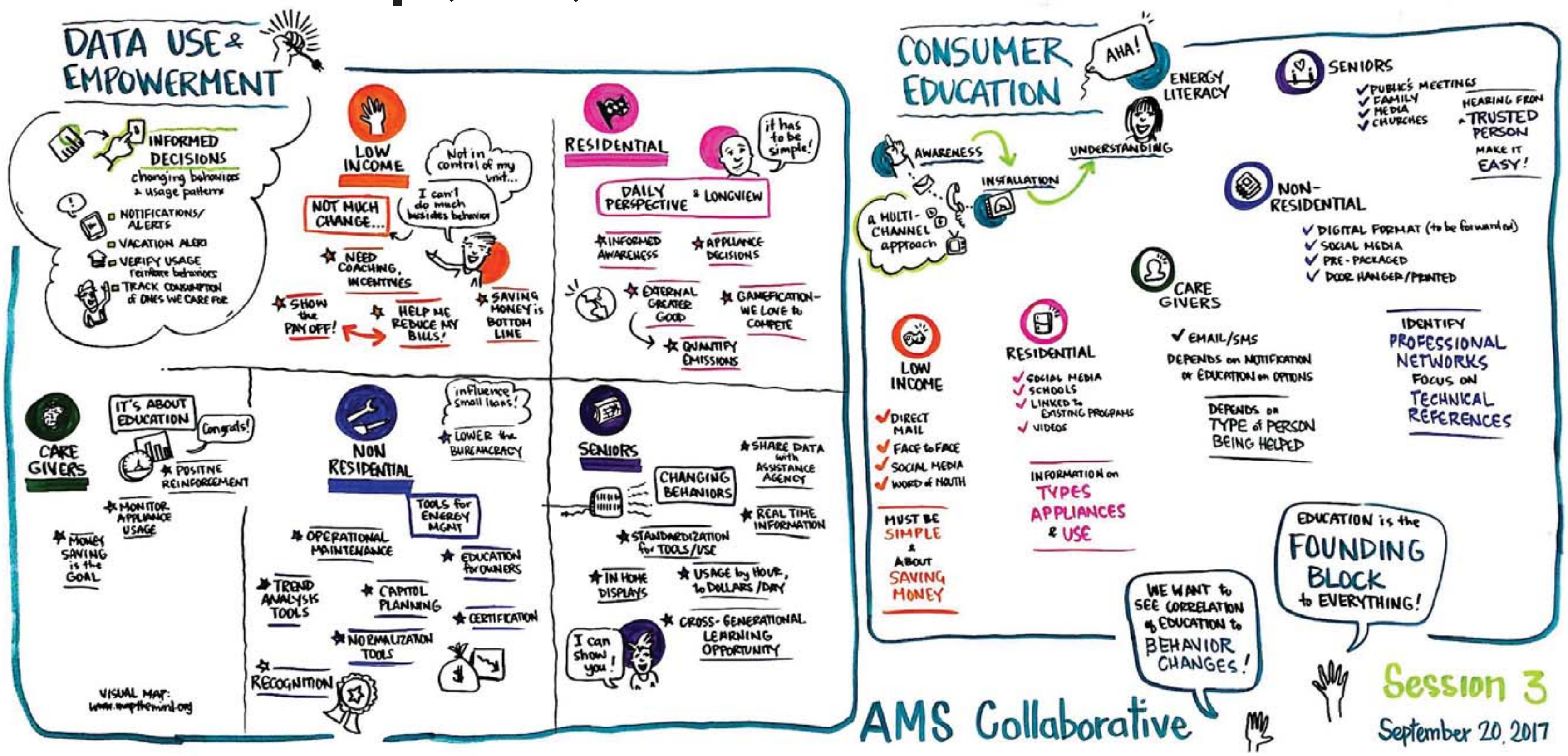




AMS Collaborative
Session #3 Visual Map

AMS Collaborative
Session #3 Visual Map (con't)



AMS Collaborative

Order	Theme	Summary Description	Estimated Duration	Planned Session
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day	2
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	1/3 Day	3
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	1/3 Day	3
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	1/3 Day	3
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	1/3 Day	4
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	1/3 Day	4
7	**Cost / Benefit Recap**	• Review of business case with adjustments	Full Day	5

SCHEDULE

AUG 22 — Costs / Benefits - Baseline

SEP 20 — Data Privacy & Data Empowerment & Customer Education

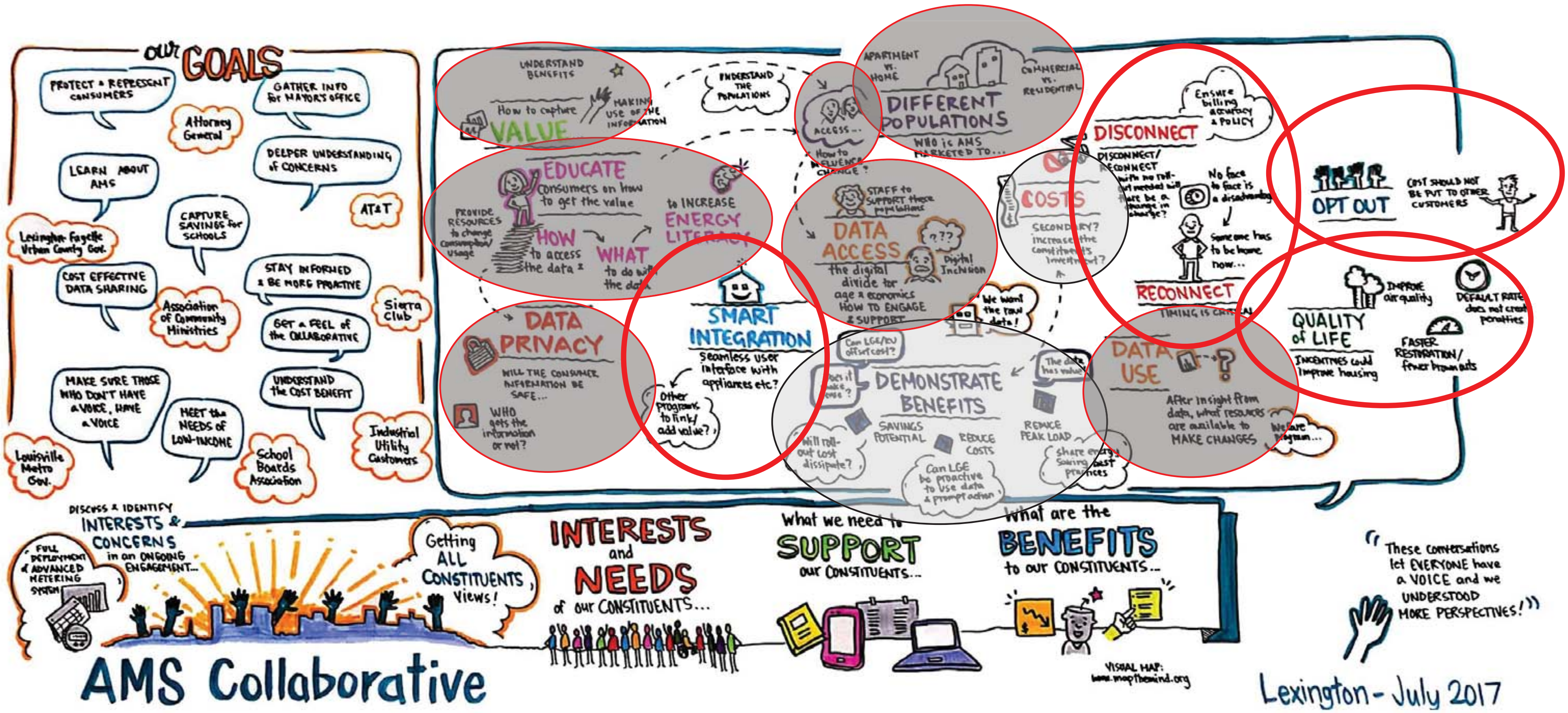
OCT 17 — Opt-out, & Remote Disconnect / Reconnect & New Services

and Education

NOV 8 — Cost / Benefit - Recap

...

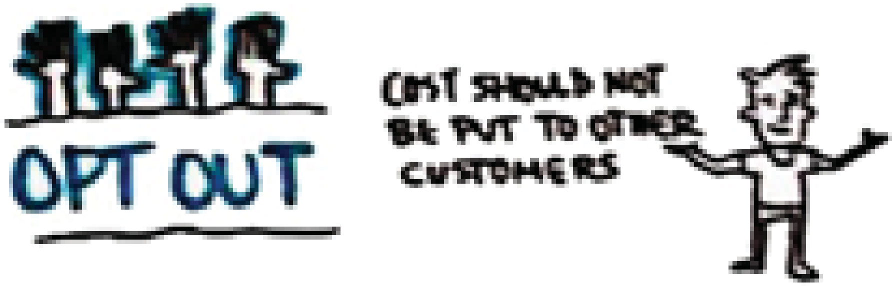
AMS Collaborative Session #1 Visual Map



Opt-out

Opt-out

- Concerns that cost of opt-out will be applied to all



Opt-out

- Initial filing did not include an Opt-out
  - November 2016 filing did not include an Opt-out provision
    1. AMS benefits are greater without an Opt-out. Opt-out is detrimental to maintaining and running the system
    2. Calculating Opt-outs is challenging (financial dilemma - costs spread across group but not knowing size of group – will require assumptions and adjustments)
    3. Case 428 was not supportive of Opt-out provisions primarily because maximum benefits are derived with maximum participation

Case 428:
"If the utility chooses to allow opt-outs, the PSC said, the program should be structured in a way that any additional costs – such as having to read meters directly, rather than remotely – be borne by the individual customers choosing to opt out."

Reference: Page 14-17, Case 2012-00428 PSC Order https://psc.ky.gov/PSCSCF/2012%20Cases/2012-00428/20160413_PSC_ORDER.pdf Filing date 4/13/2016

Question for the Collaborative

- Case 428 states that opt-out customers cover any additional costs – such as having to read meters directly, rather than remotely – be borne by the individual customers choosing to opt out.

- Should customers have the ability to opt-out of the program?

YES UNSURE NO

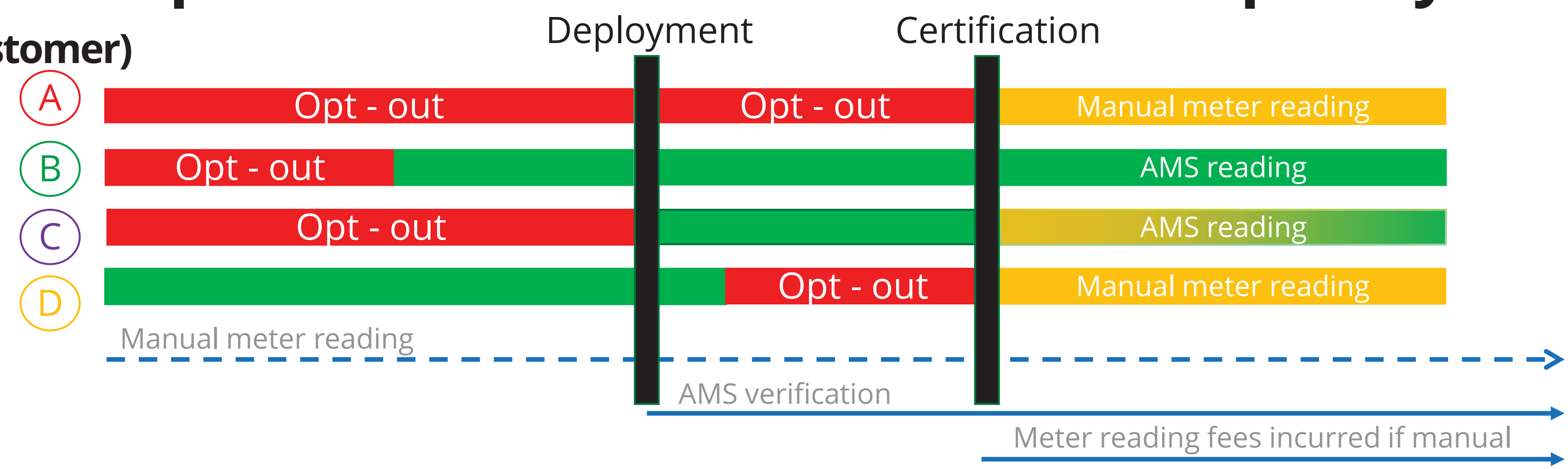
Opt-out Fees

- Opt-out Set-up Fee
  - Fee to set up and administer the Non-Standard Meter Option for each customer. This includes the overall work management of the installation/removal of the non-standard meter, if necessary.

- Monthly Fee
  - Fees to manually read the meter and maintain the systems and processes needed to support the non-standard option.

Customer Opt-out Scenario Timelines and Complexity

(same customer)



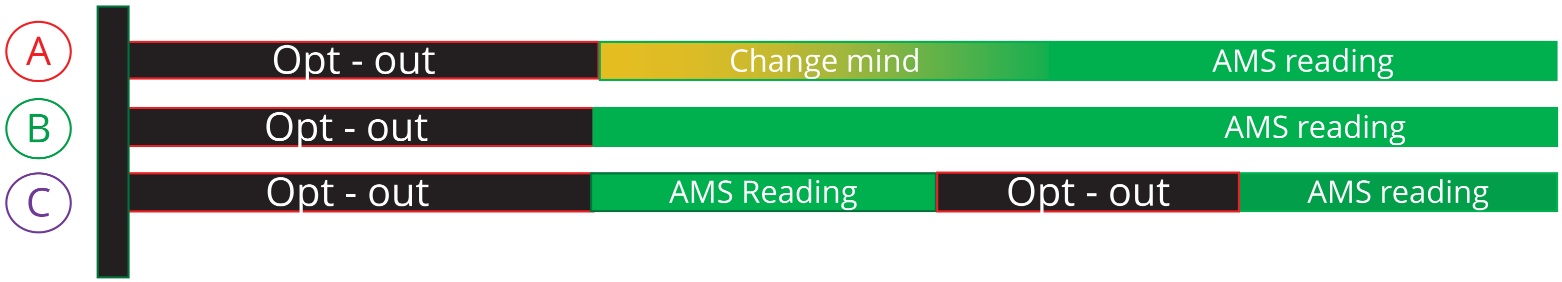
	Description	Opt-out Set-up Fee	Monthly Fees
A	Opt-out prior to deployment, and remain opt-out post AMS project completion. (Non-AMS remains.)	**Yes**	**Yes**
B	Opt-out prior to deployment, and opt back in prior to deployment (Non-AMS to AMS.)	**No** *	**No**
C	Opt-out prior to deployment, and opt back in after deployment has covered the territory but before business area certification. (Non-AMS to AMS).	**Yes**	**No** **
D	Opt-out after deployment. (AMS to non-AMS.)	**Yes**	**Yes**

*Possible fee at time of opt-out and refundable at opt-in if prior to deployment

**Monthly fees will be incurred between Business Area certification until Opt-in in the future.

Long-term Customer Opt-out Complexities

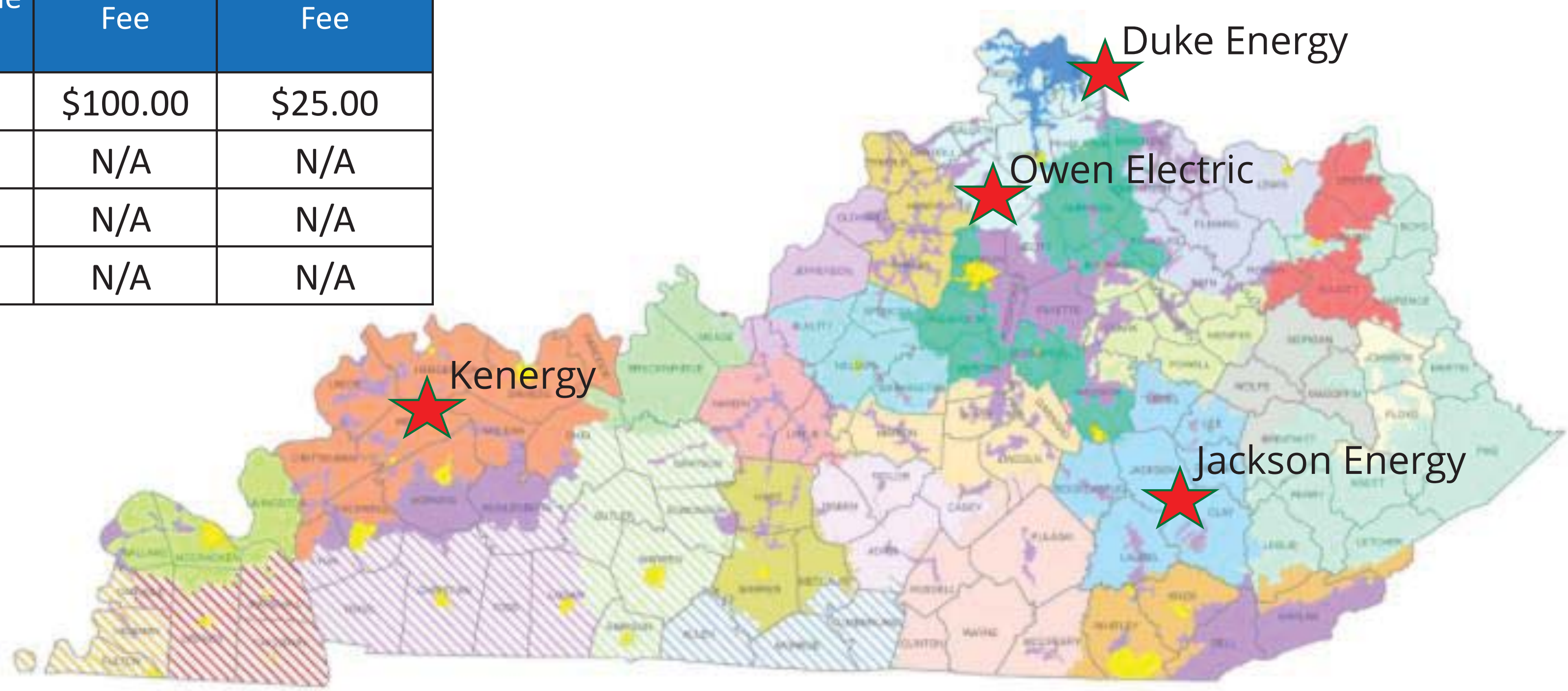
AMS fully functioning



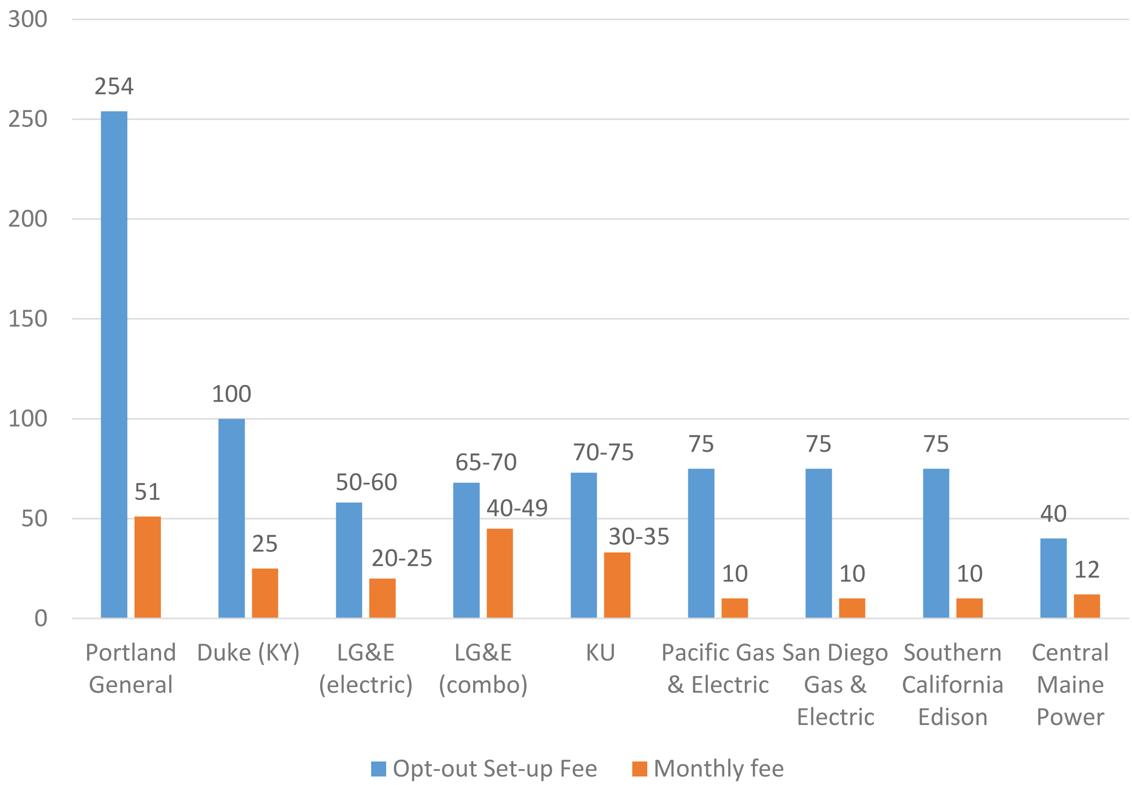
	Description	Complexities
A	Current opt-out customer decides to join program	Monthly fees will be required until meter change can be made
B	Previous customer opted-out, new customer defaults to AMS program	Who should be responsible for the opt-out set-up fee?
C	Previous customer opted-out, each tenant makes a different choice	Landlord concerned for wear and tear, request for AMS to transition property between tenants, tenant wants something else

AMI in Kentucky

Utility	Opt-out available	Opt-out Set-up Fee	Monthly Opt-out Fee
Duke	Yes	$100.00	$25.00
Kenergy	No	N/A	N/A
Owen Electric	No	N/A	N/A
Jackson Energy	No	N/A	N/A



Comparison of Opt-out Set-up and Monthly Fees



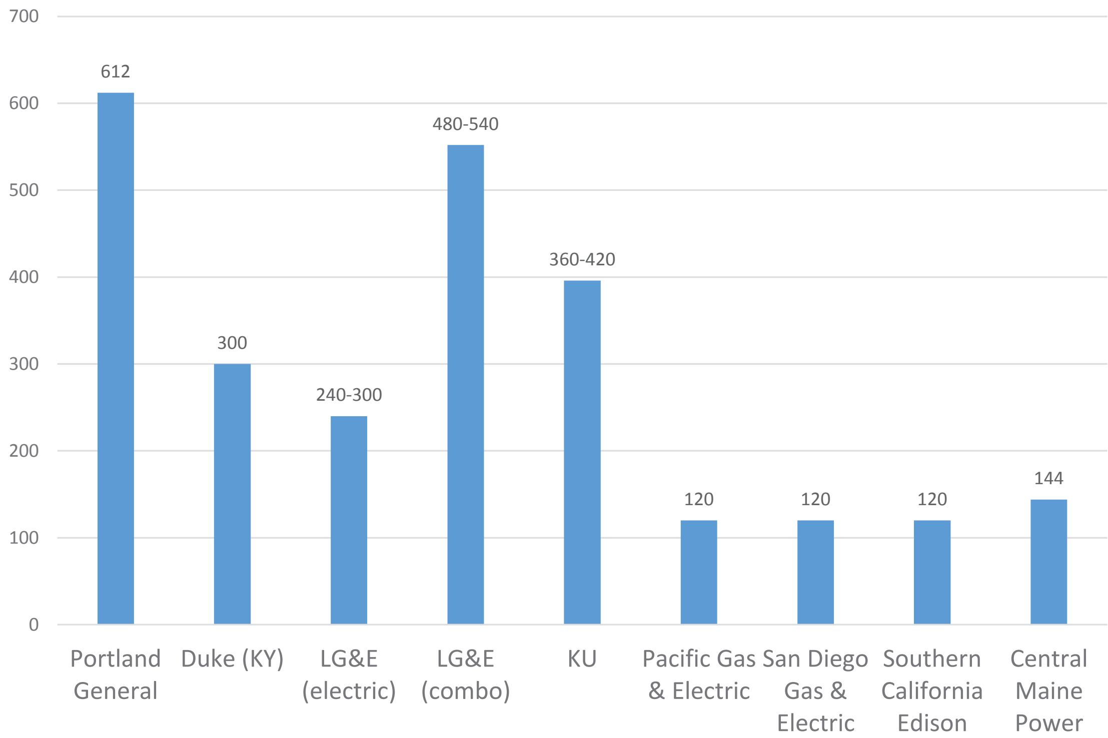
Opt-out Set-up Fee (estimated*)

— LG&E (electric) $50 - $60
— LG&E (combo) $65 - $70
— KU $70 - $75

Monthly Fee (estimated*)

— LG&E (electric) $20 - $25
— LG&E (combo) $40 - $49
— KU $30 - $35

Annualized Monthly Fees



Annualized Monthly Fees
- LG&E (electric) $240-300*
- LG&E (combo) $480-540*
- KU $360-420*

Question for the Collaborative

- Case 428 states that opt-out customers cover any additional costs – such as having to read meters directly, rather than remotely – be borne by the individual customers choosing to opt out.
- Should customers have the ability to opt-out of the program

YES

UNSURE

NO

Customer Communication (for Opt-out)

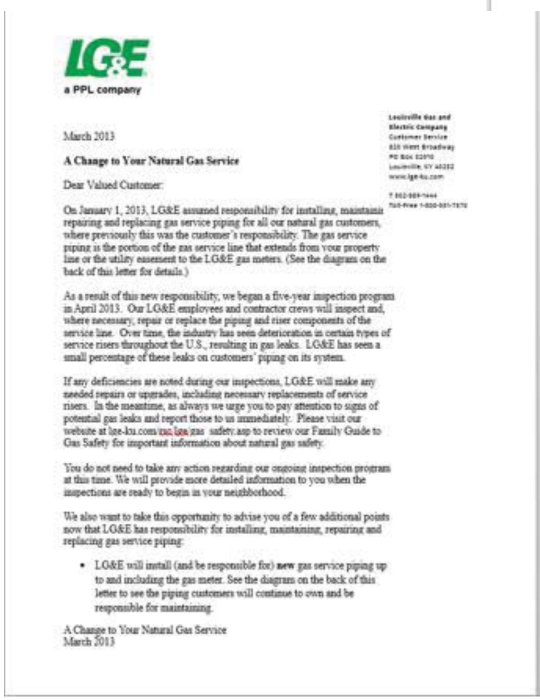
Prior to install	Prior to install	Working in area	After team has left area
Customer Notification	**Customer Notification**	**Customer Notification**	**Customer Notification**
LETTER 1 – Coming to install – Details of program and description of fees if Opt-out	LETTER 2 – Coming to install – Details of program and description of fees if Opt-out – Ombudsmen in area	LETTER 3 – Coming to install – Details of program and description of fees if Opt-out – Verification that choice is still Opt-out *"Are you still out?"*	LETTER 4 – Details on fees
Customer Service	**Customer Service**	**Customer Service**	**Customer Service**
– Specialized team	– Specialized team	– Specialized team	– Specialized team
	Ombudsmen	**Ombudsmen**	**Communication on bill**
	– Team canvassing area prior to deployment	– Team working area	– Message on bill each month with details

GOAL:
- Raise awareness
- Get objections early

Illustrative view

Example: LG&E Gas Riser Project

Customer Notification


LG&E
a PPL company

Louisville Gas and Electric Company
Customer Service
820 West Broadway
PO Box 32010
Louisville, KY 40232
www.lge-ku.com

T 502-589-1444
Toll-Free 1-800-331-7370

March 2013

A Change to Your Natural Gas Service

Dear Valued Customer:

On January 1, 2013, LG&E assumed responsibility for installing, maintaining, repairing and replacing gas service piping for all our natural gas customers, where previously this was the customer's responsibility. The gas service piping is the portion of the gas service line that extends from your property line or the utility easement to the LG&E gas meters. (See the diagram on the back of this letter for details.)

As a result of this new responsibility, we began a five-year inspection program in April 2013. Our LG&E employees and contractor crews will inspect and, where necessary, repair or replace the piping and riser components of the service line. Over time, the industry has seen deterioration in certain types of service risers throughout the U.S., resulting in gas leaks. LG&E has seen a small percentage of these leaks on customers' piping on its system.

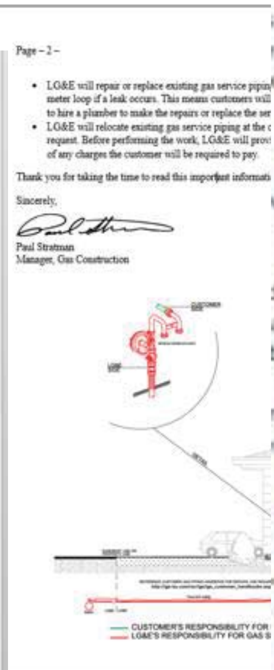
If any deficiencies are noted during our inspections, LG&E will make any needed repairs or upgrades, including necessary replacements of service risers. In the meantime, as always we urge you to pay attention to signs of potential gas leaks and report those to us immediately. Please visit our website at lge-ku.com/cus_lge/gas_safety.asp to review our Family Guide to Gas Safety for important information about natural gas safety.

You do not need to take any action regarding our ongoing inspection program at this time. We will provide more detailed information to you when the inspections are ready to begin in your neighborhood.

We also want to take this opportunity to advise you of a few additional points now that LG&E has responsibility for installing, maintaining, repairing and replacing gas service piping:

- LG&E will install (and be responsible for) **new** gas service piping up to and including the gas meter. See the diagram on the back of this letter to see the piping customers will continue to own and be responsible for maintaining.

A Change to Your Natural Gas Service
March 2013


Page – 2 –

- LG&E will repair or replace existing gas service pipin[g] meter loop if a leak occurs. This means customers will to hire a plumber to make the repairs or replace the ser[vice]
- LG&E will relocate existing gas service piping at the c[ustomer's] request. Before performing the work, LG&E will prov[ide] of any charges the customer will be required to pay.

Thank you for taking the time to read this important informati[on]

Sincerely,

Paul Stratman
Manager, Gas Construction


your home or business to relight your natural gas appliances. Someone must be present to grant access to your home or business.
lines" (the pipes that run from the gas meter to your appliances) must re your gas service is turned back on. If a leak is detected on your house service must remain off for safety reasons until you can complete the irs. This work is not something LG&E can perform because the customer sponsible for the natural gas "house lines." In some situations, we will o pavement or sidewalks. When we do, we will place a temporary fill or over the hole as a safety precaution. We will bring in our "hard surface" he work is finished to restore the pavement or sidewalk ndition.
lig into grass, we will level the ground, sow grass seed In these situations, we will need your help watering the ss will grow properly. It can take several weeks for the s.
, don't hesitate to contact the on-site foreman to ask any s you may have. It is our goal for you to be pleased with vice lines and the restoration of the surrounding property.

Q. What if LG&E finds a leak on my natural gas "house line"?

A. LG&E will always perform a safety check on the "house lines" after the riser replacement and before the natural gas appliances are relit. If a leak is detected on your "house lines", we will turn off your natural gas and let you know what steps you need to take to have the leak repaired. LG&E cannot make the necessary repairs on your "house lines". Maintenance and repairs of the "house lines" are the customer's responsibility. After you have made the repairs, call LG&E and we will send a crew as quickly as possible to perform the safety check to confirm the "house lines" are no longer leaking and then turn on your natural gas service.

Q. Will I need to contact LG&E to schedule an appointment to have the work done on my property?

A. No appointments are needed from April through November. Our crews will leave a notice on your door letting you know we are in the area doing inspection work. During the colder weather months (December through March), we will contact you to schedule an appointment to perform the work if an interruption to your gas service is necessary. If you receive a notice asking you to contact us to schedule an appointment, please call us at the number provided to schedule the work for your home or business.

Q. Will I have to be home when the work is performed?

A. No. You will not need to be home during the actual inspection and construction work. However, if we turn off your gas service, someone age 18 or older must be present to allow our crews to access your home or business to restore your service and relight your natural gas appliances.

Q. Will traffic on my street be blocked?

A. Not likely. Most of the work will be performed near your natural gas meter. As a result, we will not have to block the street or impede traffic flow. If there is a time, however, when our trucks or heavy equipment need to block the street, our crews will be on-site and can move to allow you to pass or access your driveway. Just let us know what you need.

Q. Will my street be torn up?

A. Not likely. Because most of the work will be performed near your natural gas meter, it is not likely we will need to do any work on the street.

Q. Will my yard and/or landscaping be affected?

A. Possibly. Our crews work in as small an area as possible and try to minimize any disruption to your yard or landscaping. The work will primarily affect the area around your natural gas meter, but some small excavation work will be required if we have

Exercise

Opt-out

Questions

- Group Discussion
  - Why do you think you constituents would opt out of a standard AMS meter?
  - What may influence the decisions your clients make on accepting the new AMS meter?
  - Is this fee something you would cover in assistance?
  - Fee timing- How will this impact you?
    - Opt-out Set-up fee
    - Reading fee (in the initial stages)

BREAK

Remote Service Switch (RSS)

Remote Service Switch

- Disconnects and Reconnects
  - Will this change the fees for disconnection and reconnection?
  - Will the lack of human interaction be a disadvantage?
  - Is someone required to be at home for a disconnection or reconnection?
  - What does the timing of disconnections and reconnections look like?

LG&E / KU Mission Values

Mission

- To provide reliable, safe energy at a reasonable cost to our customers and best-in-sector returns to our shareowners.

Values:

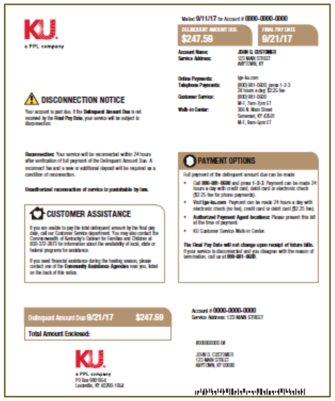
- Safety - We do not compromise on safety and health. Our objective is very simple: zero accidents and no adverse impact on the public, employees or contractors.
- Customer Focus - We provide the highest quality, safe, reasonably-priced service to all our customers, improving quality of life in the areas we serve. We anticipate and meet the needs of both our external and internal customers.
- Diversity and Engagement - We are committed to an inclusive, respectful and diverse workplace that rewards performance, enables professional development and encourages employee engagement. Employees take responsibility for results and are committed to diversity and to continual improvement.
- Performance Excellence - We have a personal commitment to excellence in all we do, taking great pride in our professionalism, attention to details and continual improvement. Each employee understands that excellent day-to-day performance and a personal focus on results are essential to producing superior results.
- Integrity and Openness - We act honestly and ethically in everything we do, adhering to the highest standards of integrity. We honor our commitments, take personal responsibility for our actions and communicate openly.

Remote Service Switch Capabilities

- Remote Connect for Move-Ins
- Remote Connect after Payment
- Remote Disconnect for Move-Out
- Remote Disconnect for Non-payment
- Remote Disconnect for some Safety Issues/Responses

Current Disconnection Notice Process

This is an automated process

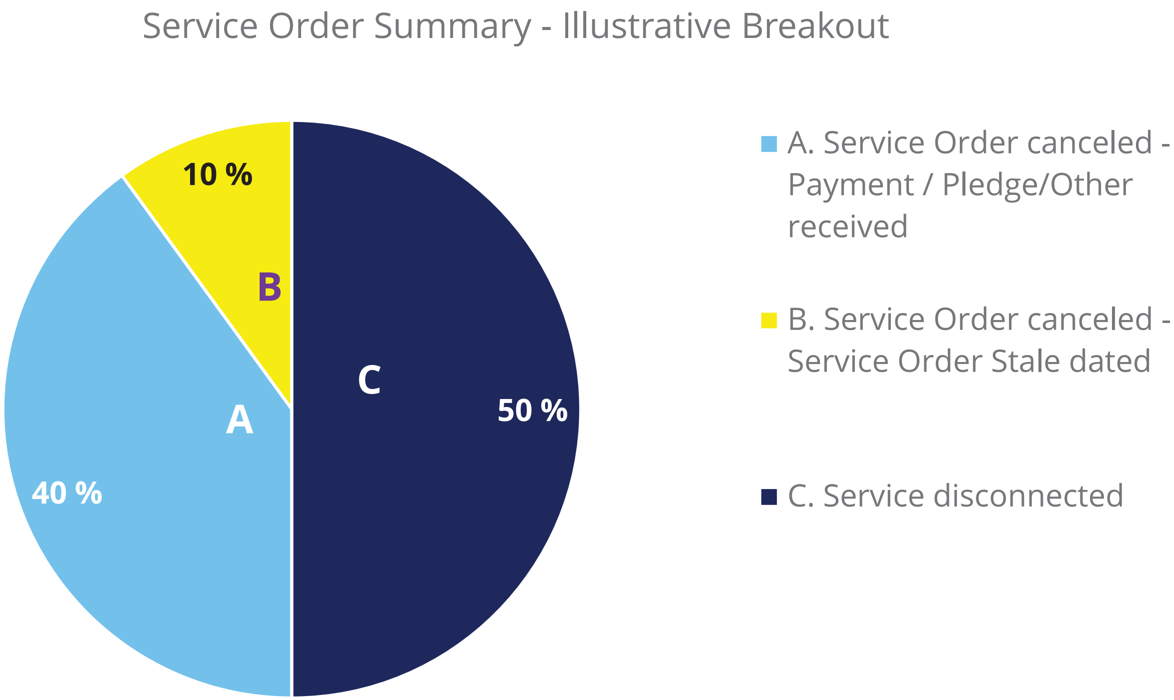
Bill is generated in CIS Bill is sent to Customer	16 business days	10 days later	Outcomes
Bill is generated in Customer Information System based on the customer's billing cycle. Bill is sent to Customer.	If payment is not received within 16 days, a Brown Bill is sent out.  *As soon as the brown bill is received - Best time to reach out to advocacy groups	If payment has not been received, create service order to disconnect service for the following business day.	A. If payment or pledge is made before service technician gets to the disconnection location, service order is removed and disconnection is canceled. B. Service technician disconnects service for non-payment. C. Service technician does not get to account within 4 day window, service order becomes stale and is removed from work queue and cycle begins again the following month

LKE Disconnect Service Orders – Illustrative Breakout

A. If payment or pledge is made before service technician gets to the disconnection location, service order is removed and disconnection is canceled.

B. Service technician disconnects service for non-payment.

C. Service technician does not get to account within 3 day window, service order becomes stale and is removed from work queue and cycle begins again the following month



Based off data from 2016

Practices

Today

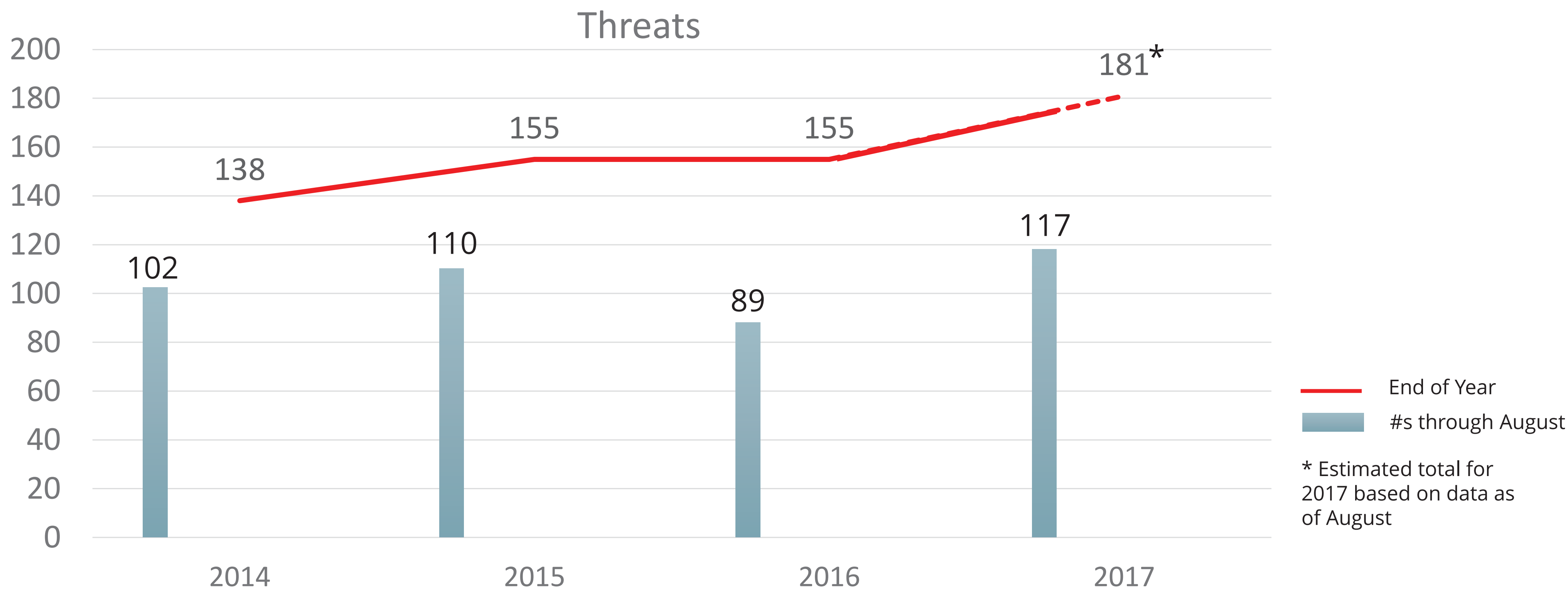
- Electric Service
  - Technician required to access the meter (including indoor meters)
  - No one is required to be at the premise for service connection or disconnection
- Gas Service
  - Technician required to access the meter
  - Mandatory for someone to be at the premise for service reconnection
- Note
  - During extreme temperatures, electric and gas service will not be disconnected

Remote Service Switch

- Electric Service
  - Service can be turned on and off remotely and does not require physical access to the premise
  - No one is required to be at the premise for service connection or disconnection
- Gas Service – Not impacted by RSS
  - Technician required to access the meter
  - Mandatory for someone to be at the premise for service reconnection
- Note
  - During extreme temperatures, electric and gas service will not be disconnected

Threats to Employees

Threats are Increasing



Exercise

Remote Service Switch

Questions

- Timing
  - When should disconnects occur?
  - Should they be at once or spread out?
  - Should move-ins or reconnections occur anytime
  - What impacts may the timing of disconnections have on our services?

- Notification
  - When should notifications of service change be communicated?
  - What type of notifications would be best received?

LUNCH

New Services

New Services:
Your perspective

Once AMS is fully installed and meter data is available, what new services can you imagine?

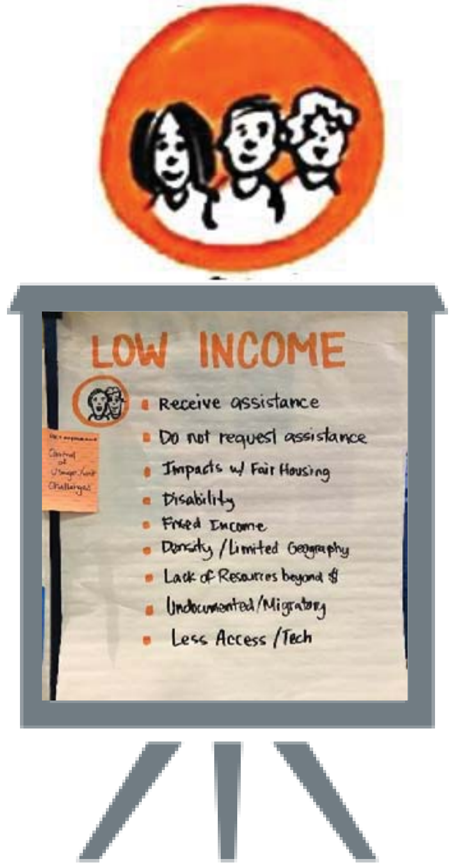
What new services do you need to take advantage of the new data that will be available through AMS?

New Services:
Customer Focused

- New rates
- Analytics and Loss detection
- Platform for future products
- Green Button Initiatives
- Distributed Energy Resources
- Monitoring and Notification

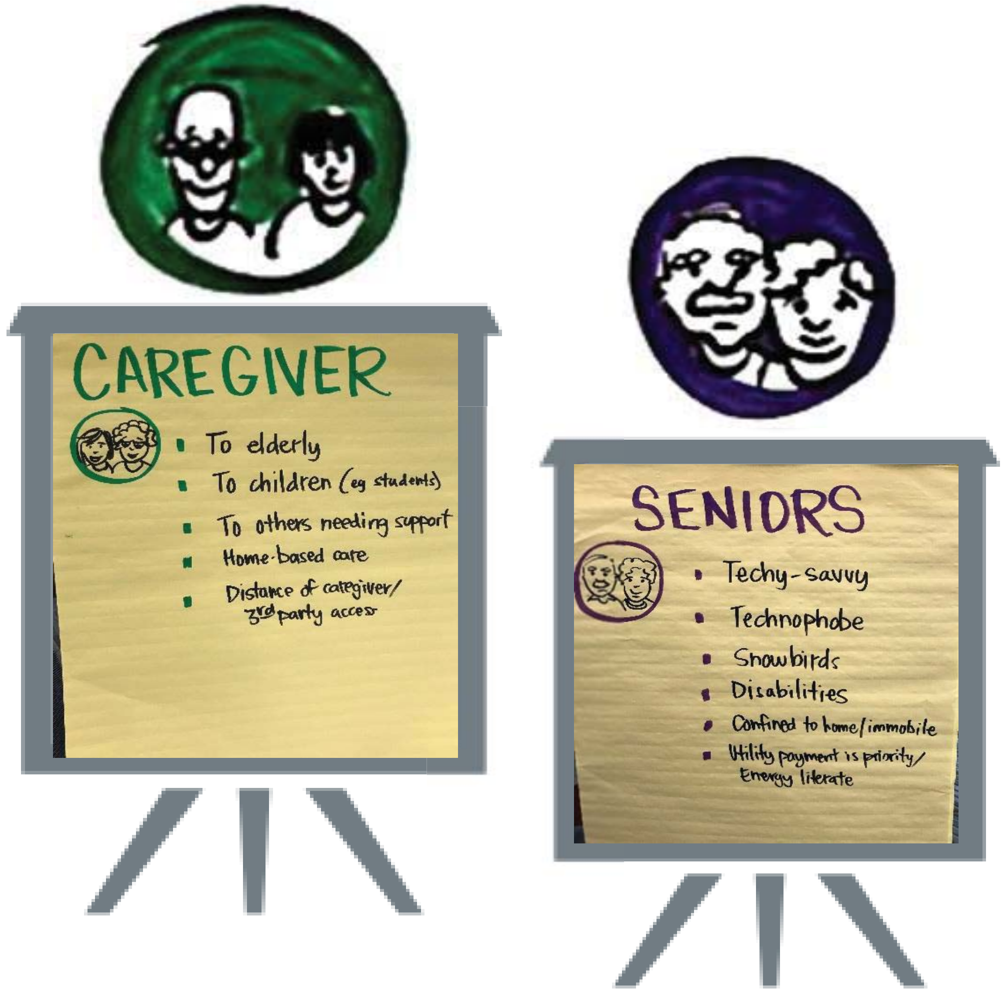
New Services: Persona based

Based on data from AMS , what new services might benefit this persona



New Services: Persona based

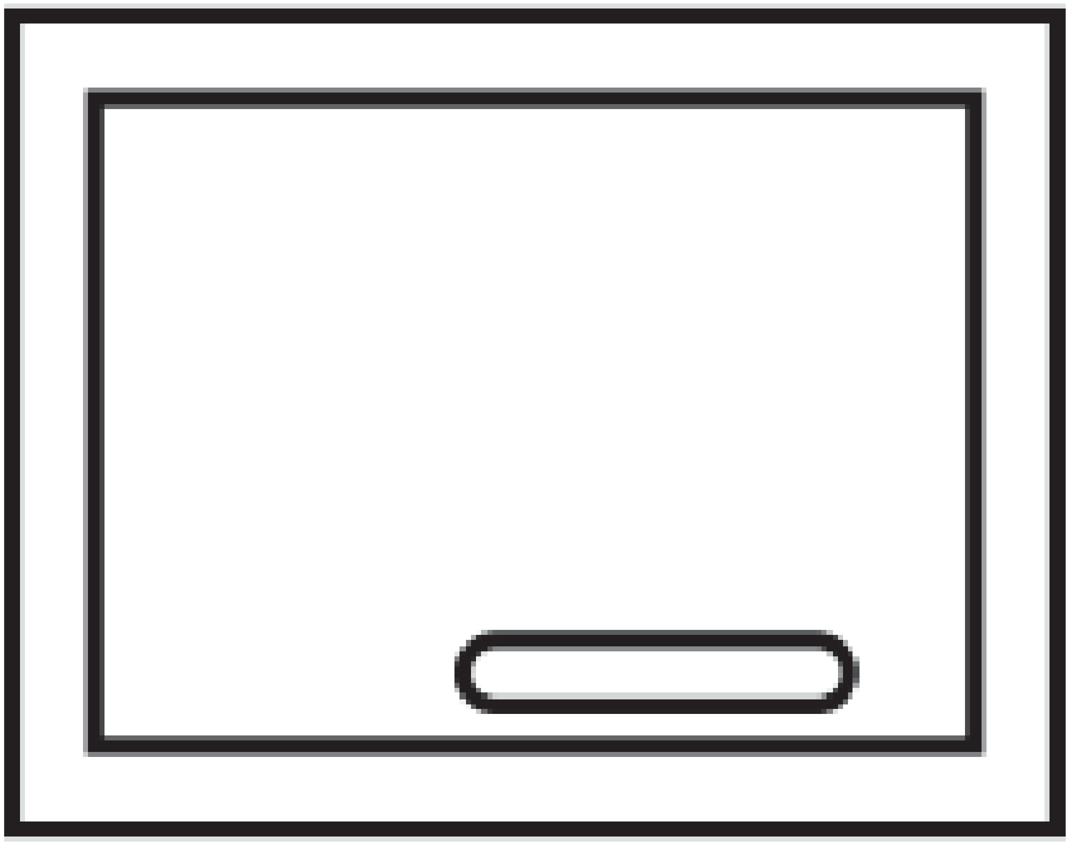
Based on data from AMS , what new services might benefit this persona



New Services: Persona based

Based on data from AMS , what new services might benefit this persona

What have we missed?



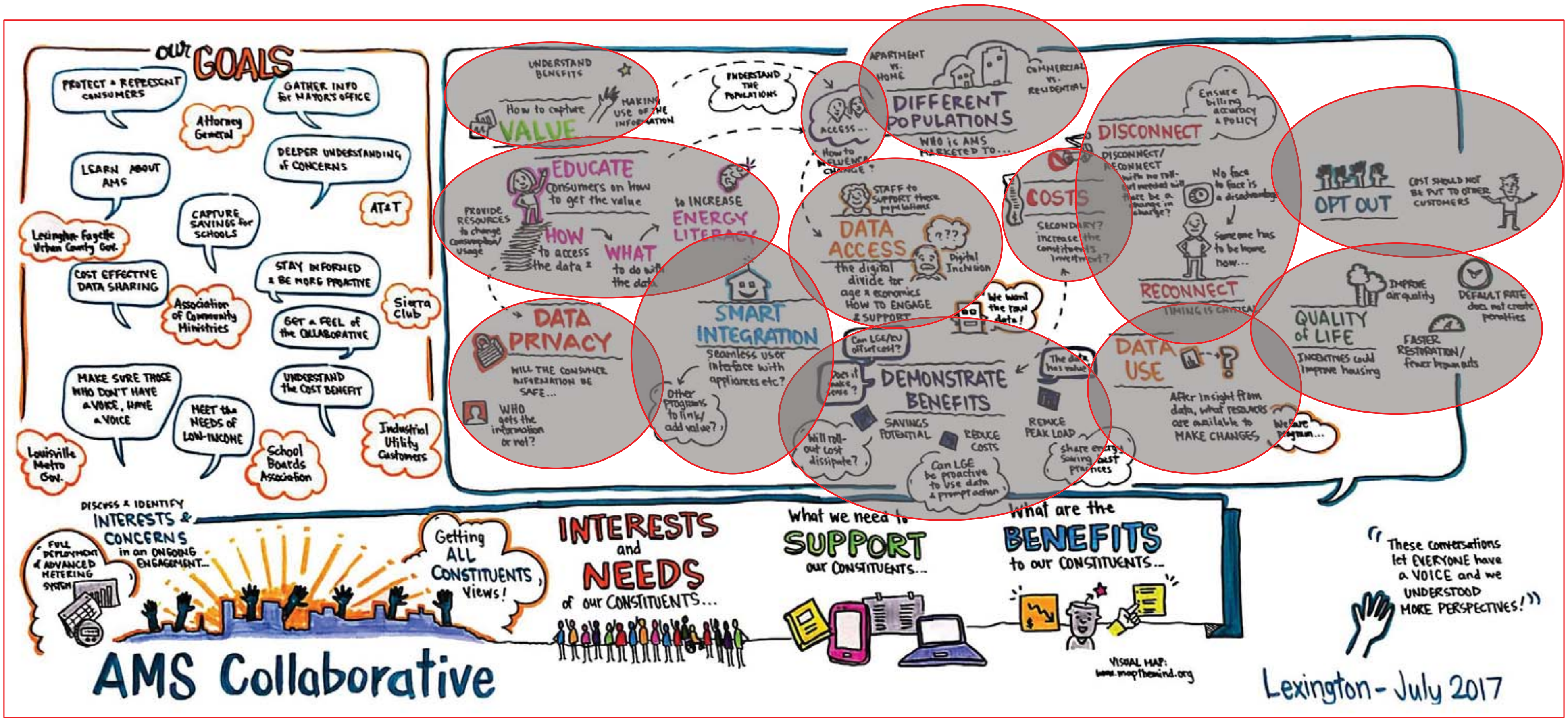
Education

- What more are you wanting to see from an education perspective?

BREAK

COLLABORATIVE CHECK POINT

AMS Collaborative Session #1 Visual Map



FORWARD

AMS Collaborative

Order	Theme	Summary Description	Estimated Duration	Planned Session
1	**Cost / Benefit Baseline**	• Review upfront to provide baseline; re-visit in each topic, as needed	Full Day	2
2	**Data Privacy / Sharing**	• Protections for consumer data and potential opportunities for sharing to gain further value from AMS	1/3 Day	3
3	**Data Empowerment**	• How to use data to make better decisions and achieve benefits of energy management	1/3 Day	3
4	**Education**	• Pre-implementation information / installation process and timing and post-implementation education on how to find, use data and available resources to take action	1/3 Day	3
5	**Remote Disconnect / Reconnect**	• Current practices / fees and potential changes for AMS • Opportunities / challenges due to remote service capability	1/3 Day	4
6	**New Services**	• Rate options, tools to use / interpret data, notifications, etc.	1/3 Day	4
7	**Cost / Benefit Recap**	• Review of business case with adjustments	Full Day	5

SCHEDULE

AUG 22	SEP 20	OCT 17	NOV 8 ...
Costs / Benefits - Baseline	**Data Privacy & Data Empowerment & Customer Education**	**Opt-out, & Remote Disconnect / Reconnect & New Services** and Education	**Cost / Benefit - Recap**

THANK YOU

AMS Collaborative
October 17 Session Summary

LG&E KU
PPL companies

AMS Collaborative Session #4 – Logistics

Tuesday, October 17, 2017
9:00 AM – 4:00 PM ET
Kentucky Chamber of Commerce

Collaborative Objectives:
- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests and questions

Session #4 Objectives:
- Discuss options for customer opt-out of AMS
- Review current policies and processes on service disconnection today
- Discuss needs and solutions of customers and advocacy groups that encounter service interruptions for non-payment
- Identify new services that could be enabled through AMS and AMS provided data

PARTICIPANTS

Participant	Organization
James Bush	LFUCG
Richard Dugas	LFUCG
Cathy Hinko	MHC
Lisa Kilkelly	Association of Community Ministries
Melissa Tibbs	CAC
Ron Willhite	KSBA
Barry Zalph	Sierra Club
David Huff Wendy Wagoner Shannon Montgomery Sara Judd Lora Aria Cheryl Williams Joni Votaw	LG&E / KU
Jamie Hart Phyllis Goodson Maria Ferreira-Cesar	Accenture
Julie Gieseke	Accenture / Map the Mind

AGENDA

Topic	Time	Host
Safety Moment, Agenda, Session 3 Review, and Framework of Session 4	9:00 AM	Phyllis Goodson
Opt-out	9:30 AM	Wendy Wagoner
Opt-out Discussion	10:00 AM	Facilitated
Break	10:30 AM	
Remote Service Switch	10:45 AM	Shannon Montgomery
Remote Service Switch Discussion	11:15 AM	Facilitated
Lunch	12:00 PM	
New Services Discussion	12:30 PM	Facilitated
Break	2:00 PM	
Collaborative Journey	2:15 PM	David Huff
Session 4 Recap and upcoming Session 5	2:45 PM	David Huff

Opt-out

1. Mixed opinions on desire for an opt-out program.

2. Discussion of opt-out set-up fee and monthly fees. Fees would be cost based. Discussion of challenges for estimating fees prior to knowing the actual number that may select opt-out.

3. Discussed complexities associated programmatically managing opt-outs. (i.e., Timing during deployment, changes between customers.)

4. Discussed current status of other AMI utilities in Kentucky regarding opt-out.

5. Communication of opt-out must be clearly explained for customer population (all levels).

Remote Service Switch

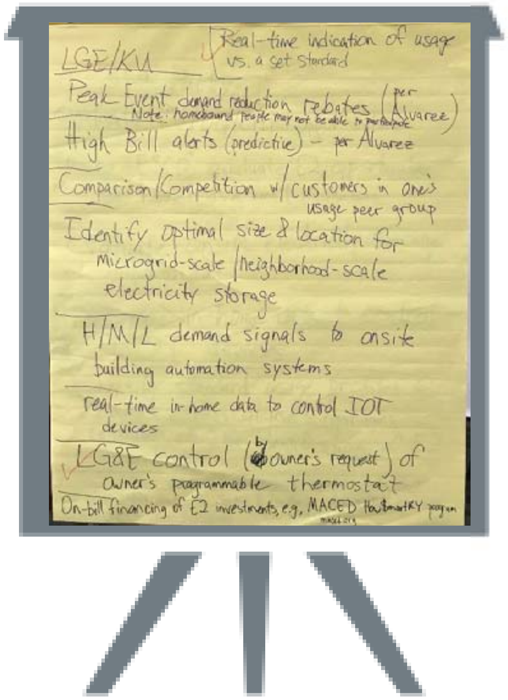
1. Discussed service disconnection and reconnection processes and practices in place today.

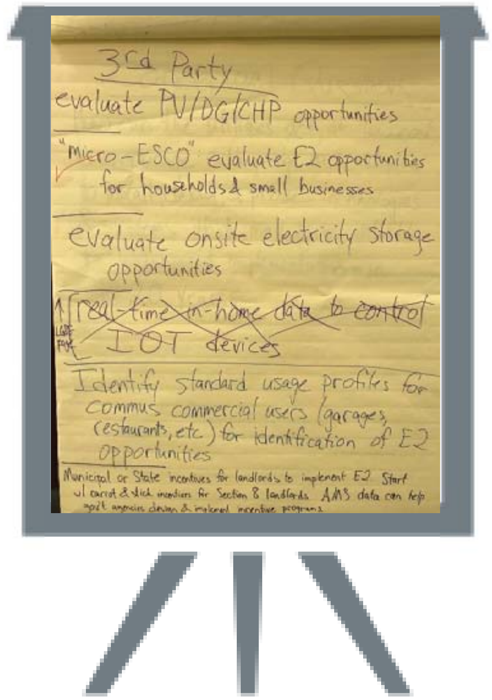
2. Provided break-out of disconnection service order outcomes (based on 2016 data). Current practices and policies for providing customer assistance will not change in the AMS environment.

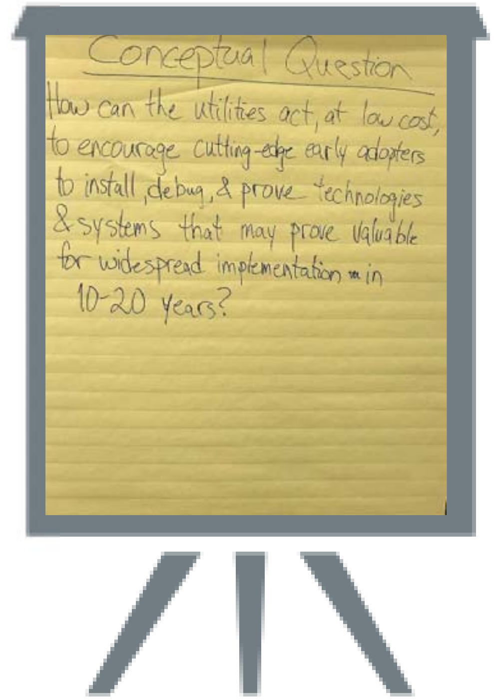
3. Discussed remote service switch facilitated multiple move-in and move-out as well as faster reconnection times for move–ins and reconnections.

New Services

What new services do you need to take advantage of the new data that will be available through AMS?







New Services

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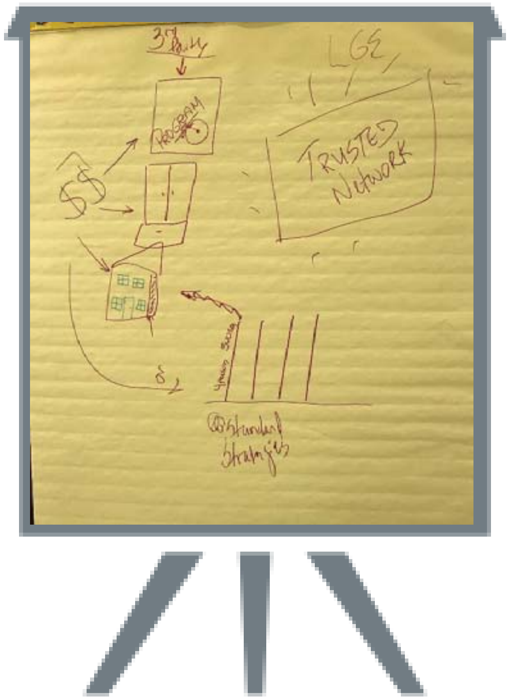
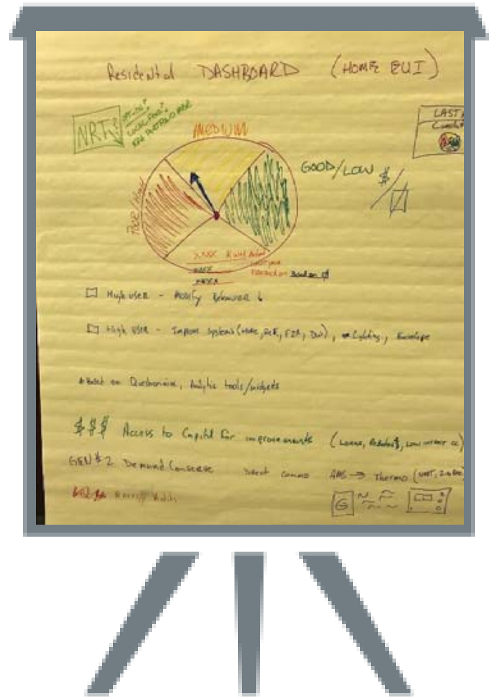
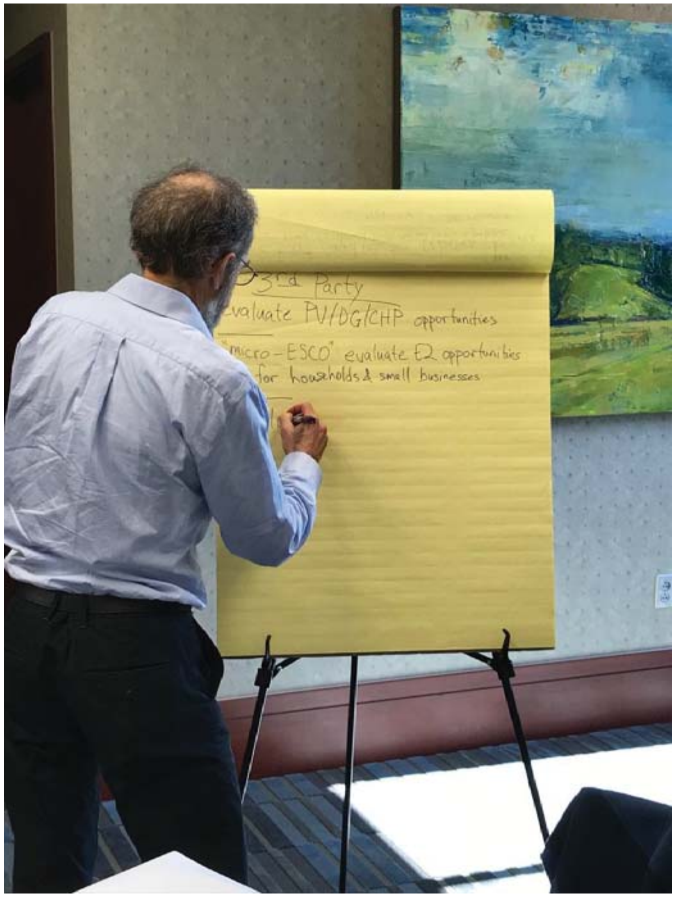
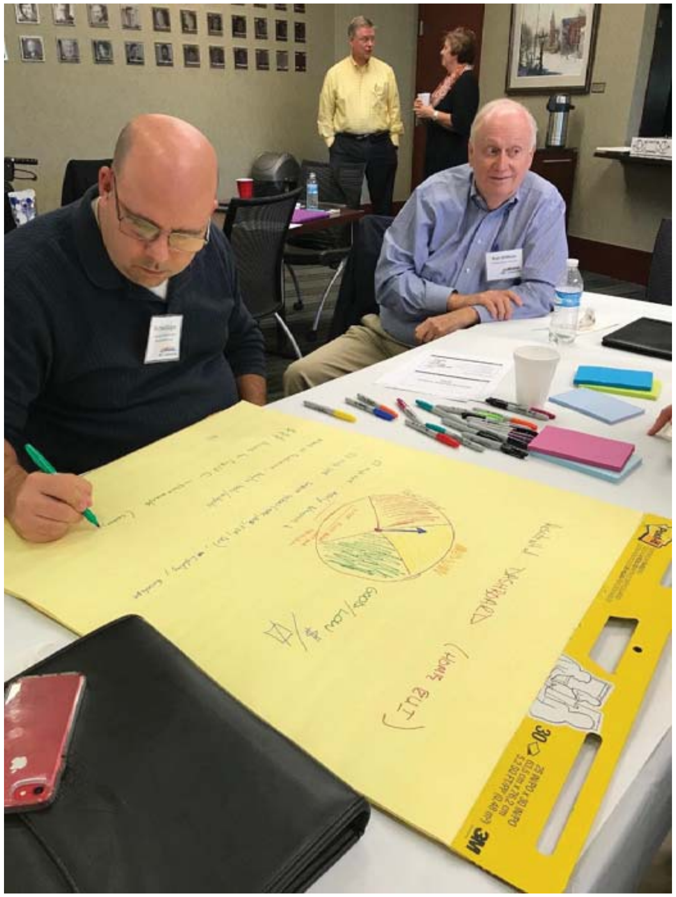




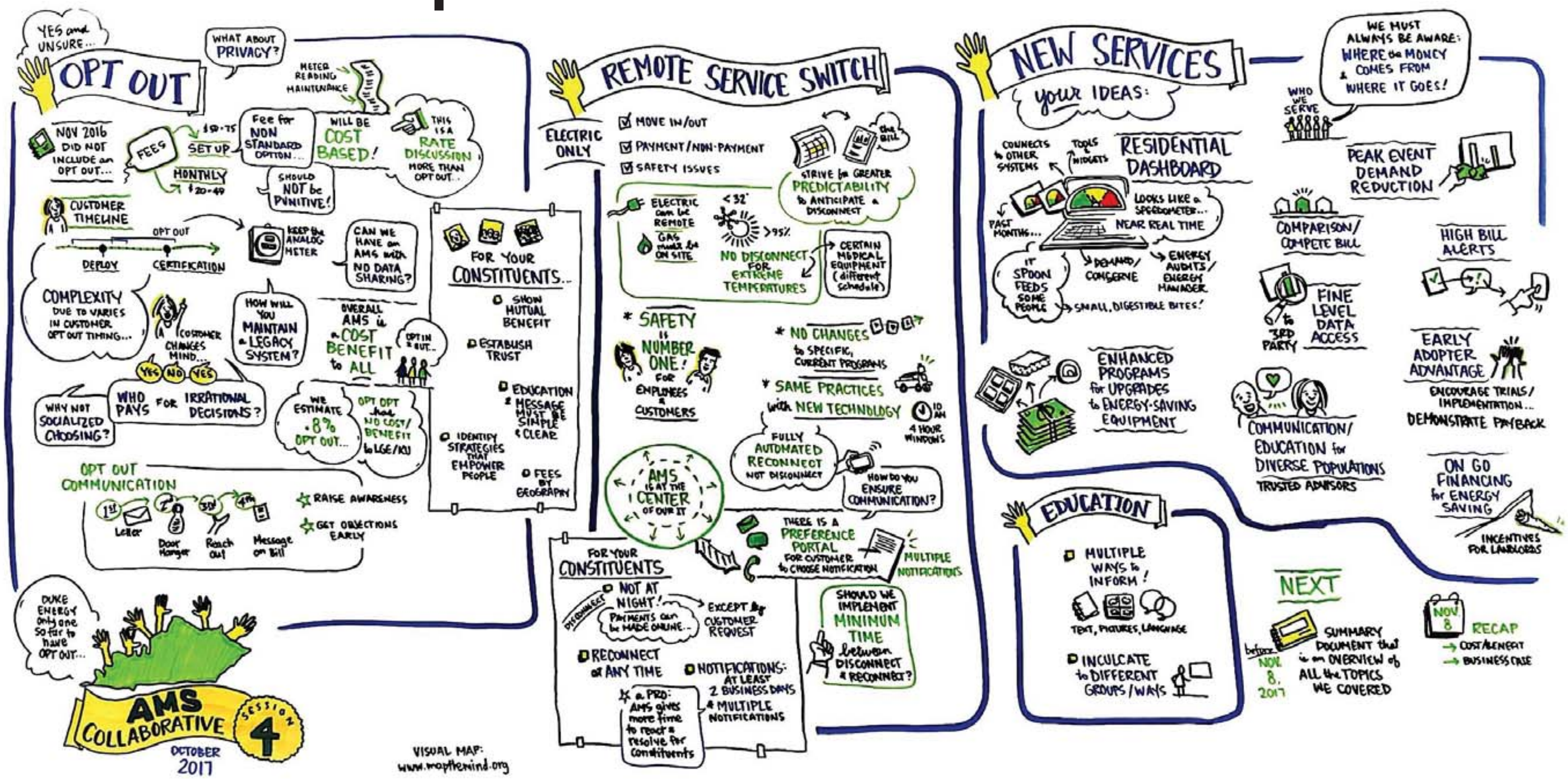
Collaboration





Everyone participates

AMS Collaborative
Session #4 Visual Map



AMS Collaborative Upcoming Session Dates

NEXT MEETINGS

- Meeting times are scheduled for 9:00 a.m. to 4:00 p.m. to allow for all materials to be covered and provide ample time for discussion and questions

- Next Meeting:

  November 8, 2017, 9:00 a.m. @

  Fairfield Inn & Suites

  40 Chenault Road, Frankfort KY

NOV 8 ...

Cost / Benefit - Recap

AMS Collaborative
Session 5 - November 8, 2017

PPL companies

Exhibit DEH-5
Page 1 of 43
Huff

Safety Moment

EXITS and EVACUATION ROUTES

- Exits
  - Main entrance and directly across on opposite end of hall
  - Through boardroom to outside door
- If evacuation is required
  - Go to the far end of the parking lot across from the main entrance of the building
- Restrooms
  - Down the hall

Fall Safety

5 tips for being safe

1. Have your furnace inspected by a qualified technician.
2. Inspect your chimney to make sure it is unobstructed.
3. Don't place a portable heater in high-traffic areas and keep away from curtains, beddings, clothes and furniture.
4. Keep dry leaves away from outdoor lighting, outlets and power cords.
5. When working with a ladder, always carry it parallel to the ground and be sure to look up and only stand it up in an area clear of overhead power lines.

Agenda – Collaborative

Topic	Time	Host
Safety Moment, Agenda, Session 4 Review, and Framework of Session 5	9:00 AM	Phyllis Goodson / David Huff
Business Case Costs	9:45 AM	Lora Aria
Break	10:45 AM	
Business Case Costs (continued)	11:00 AM	Lora Aria
Business Case Benefits	11:30 AM	Lora Aria
Lunch	12:30 PM	
Business Case Benefits (continued) and Summary	1:00 PM	Lora Aria
Break	1:45 PM	
Opt-Out	2:00 PM	Wendy Wagoner
Gallery Walk	2:30 PM	David Huff
Next Steps	3:15 PM	David Huff

AMS Collaborative Objectives

OVERALL

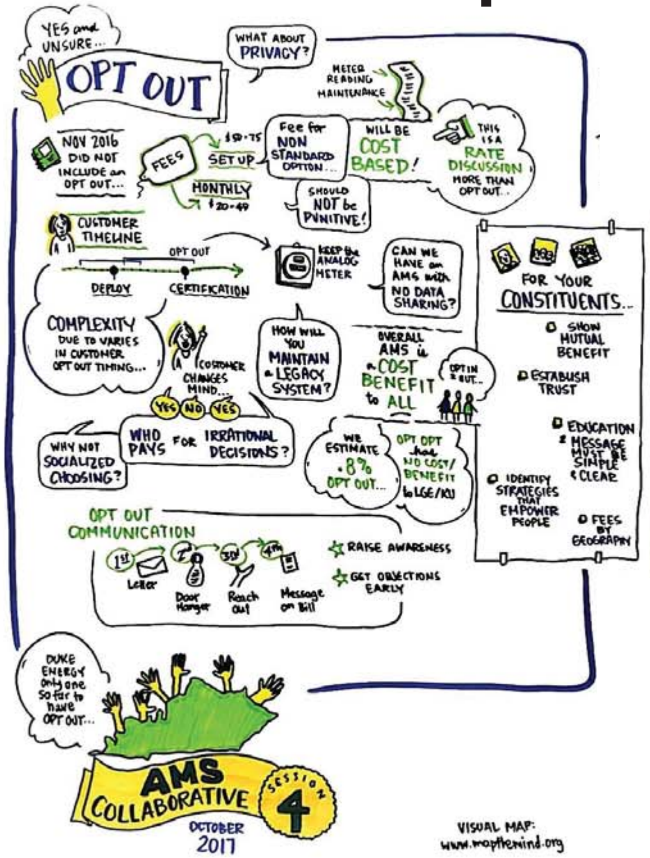
- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests

TODAY

- Review cost/benefit changes from previous business case
- Share additional information associated with Opt-out program fees
- Encourage discussion and questions to clarify updated information

AMS Collaborative Session 4 Review

AMS Collaborative
Session #4 Visual Map



AMS Collaborative Positioning for the Future

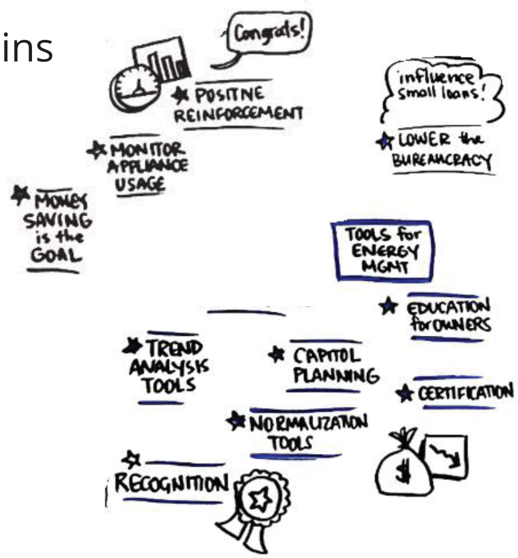
Potential Advantages of an AMS program

AMS allows customers to…

- Track usage consumption /patterns
- Change behaviors to save money
- Receive notifications / alerts
- Receive vacation alerts
- Greater predictability on disconnections
- Minimize utility presence on customer site
- Flexibility with move-ins and move-outs

New Tools later could…

- Monitor appliance usage
- Reduce operational maintenance
- Influence loans for improvements
- Provide positive reinforcement
- Encourage positive outcomes through awareness, certifications, and peer competition



New Services

- Residential dashboard for near real-time information
- Enhanced programs for upgrades to energy-saving equipment
- Tools to compare future variable rates
- High bill alerts
- Peak event demand reduction choices
- More data for future 3rd party service providers that customers initiate

LG&E KU PPL companies

Building a strong foundation for the future

Positioning for the future

Potential New Services

Customer Experience
- Cust. Service / Call Center Improvements
- Alternate Rate decisions
- Notifications – Disconnection / Outages
- Move-in and out experience
- Smart thermostats / appliances usage
- Minimize presence on private property

Future Customer Enhancements
- Smart thermostats / appliances capabilities
- Alternate rate decisions
- Bill projections
- Distributed generation integration
- Green button and Orange Button initiatives
- Data for 3rd party (loans, efficiency)
- Data to empower variable rate selection

Utility – Reliability / Operations
- Combined with ADMS, DA, and FLISR, monitor grid conditions and increase operators visibility
- Reliability of grid /DER /PEV/PV
- DLC
- Potential interactions with DR programs

Distribution Systems Integration

Meter Operations Center & Remote Service Switch Integration

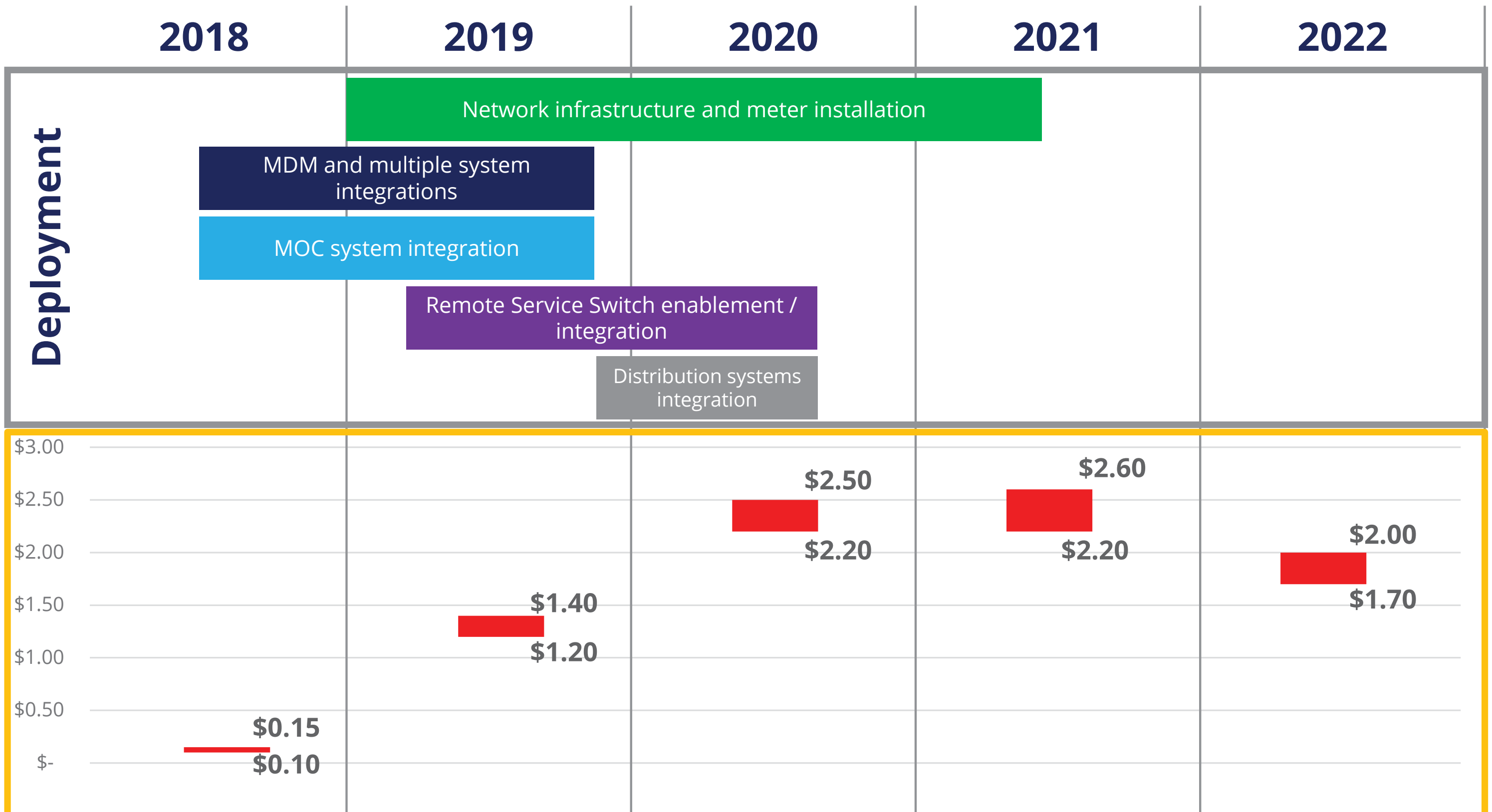
Full-scale ePortal data access

Meter Data Management System and Multiple System Integrations

Network Infrastructure & Meter Installation

3+ project years

Estimated bill impact



Illustrative of the estimated monthly average residential electric bill impact compared to 2017

$349.8M (nominal) spent in the first 5 years of the project translate to an estimated peak cost of $2.60 per month per customer

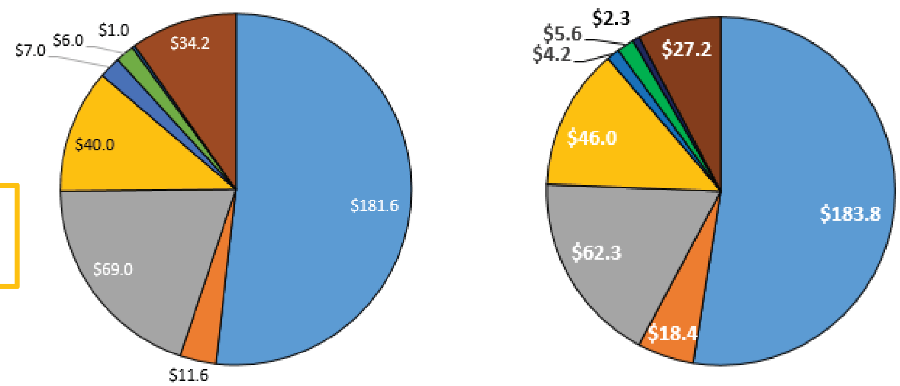
BUSINESS CASE COSTS

Comparison of original and refined business cases: 5-year view

Original: $350.4M 2016-2021

Refined: $349.8M 2018-2022

Total delta over 5-year view is -$0.6M



Category	Original Capital	Original O&M	Original Total	Refined Capital	Refined O&M	Refined Total	Delta Total
Meters	$167.0	$14.6	**$181.6**	$171.1	$12.7	**$183.8**	**$2.2**
Network	$10.4	$1.2	**$11.6**	$16.8	$1.6	**$18.4**	**$6.8**
Information Technology	$56.7	$12.3	**$69.0**	$52.1	$10.2	**$62.3**	**-$6.7**
Systems Integration	$40.0	$0.0	**$40.0**	$46.0	$0.0	**$46.0**	**$6.0**
Program Management	$5.1	$1.9	**$7.0**	$4.2	$0.0	**$4.2**	**-$2.8**
Communications	$6.0	$0.0	**$6.0**	$1.2	$4.4	**$5.6**	**-$0.4**
Change Management	$1.0	$0.0	**$1.0**	$1.4	$0.9	**$2.3**	**$1.3**
Contingency	$34.2	$0.0	**$34.2**	$27.2	$0.0	**$27.2**	**-$7.0**
Total	**$320.4**	**$30.0**	**$350.4**	**$320.0**	**$29.8**	**$349.8**	**-$0.6**

Metering

Description	Original	Refined	Delta	Explanation
Capital				
Metering equipment	$125.9M	$123.5M	- $2.4M	• Volume of gas modules increased by ~4%. • Reduced electric equipment cost. • Included sales tax on equipment.
Metering equipment installation	$32.6M	$31.7M	- $0.9M	• Reduced installation cost. • Included deployment vendor management.
Spare inventory and ancillary metering expenses	$8.5M	$15.9M	$7.4M	• Reduced spare inventory costs. • Included inventory carrying costs associated with new purchased equipment. • Reallocated labor associated with deployment readiness.
O&M				
Electric meter base repairs	$8.9M	$7.4M	- $1.5M	• Reduced meter base repair cost.
Testing of removed electric meters	$5.7M	$3.5M	- $2.2M	• Refined understanding of meter testing needs and requirements.
Warehousing, back-office support, etc.	$0.0M	$1.8M	$1.8M	• Included costs associated with warehousing removed meters. • Reallocated labor costs associated with maintaining an AMS engineering organization.
Total	$181.6M	$183.8M	$2.2M	

Network and Network Maintenance

Description	Original	Refined	Delta	Explanation
Capital				
Collector and router equipment	$4.8M	$7.6M	$2.8M	• Increased router and collector counts based on more detailed understanding of network needs.
Installation costs, planning and engineering, training, and testing	$4.9M	$8.8M	$3.9M	• Increased costs associated with increased equipment count.
Backhaul and miscellaneous equipment, and component replacement	$0.7M	$0.5M	- $0.2M	• Revised pricing estimates.
O&M				
Ongoing labor and maintenance to support network infrastructure	$1.2M	$1.5M	$0.3M	• Increased support and operating expenses associated with increased equipment count.
Total	$11.6M	$18.4M	$6.8M	

Information Technology

Description	Original	Refined	Delta	Explanation
Capital				
Software, hardware, licensing, IT developmental labor	**$56.7M**	**$52.1M**	**- $4.6M**	• Refined software, hardware, storage, licensing, labor needs.
O&M				
Maintenance, vendor support, ongoing internal IT resources costs	**$12.3M**	**$10.2M**	**- $2.1M**	• Refined maintenance and ongoing operating needs for software, hardware, and storage. • Re-allocated labor costs associated with maintaining a MOC organization.
Total	**$69.0M**	**$62.3M**	**- $6.7M**	

System Integrator

Description	Original	Refined	Delta	Explanation
Capital				
Integration across Company systems	**$40.0M**	**$46.0M**	**$6.0M**	• Refined system integrator support needs based on detailed scope and updated project timeline.
Total	**$40.0M**	**$46.0M**	**$6.0M**	

Program Management

Description	Original	Refined	Delta	Explanation
Capital				
Program management through deployment	**$5.1M**	**$4.2M**	**- $0.9M**	• Refined project management needs during deployment.
O&M				
Ongoing Program support beyond deployment	**$1.9M**	**$0.0M**	**- $1.9M**	• Program management costs beyond the deployment years have been moved to the MOC organization and AMS Engineering organization.
Total	**$7.0M**	**$4.2M**	**- $2.8M**	

Communications

Description	Original	Refined	Delta	Explanation
Capital				
Customer education	**$6.0M**	**$1.2M**	**- $4.8M**	• Customer education costs were removed from capital expenses and recategorized as O&M. Labor for the development of customer communications remains in capital.
O&M				
Customer education	**$0.0M**	**$4.4M**	**$4.4M**	• Revised the customer education plan.
Total	**$6.0M**	**$5.6M**	**- $0.4M**	

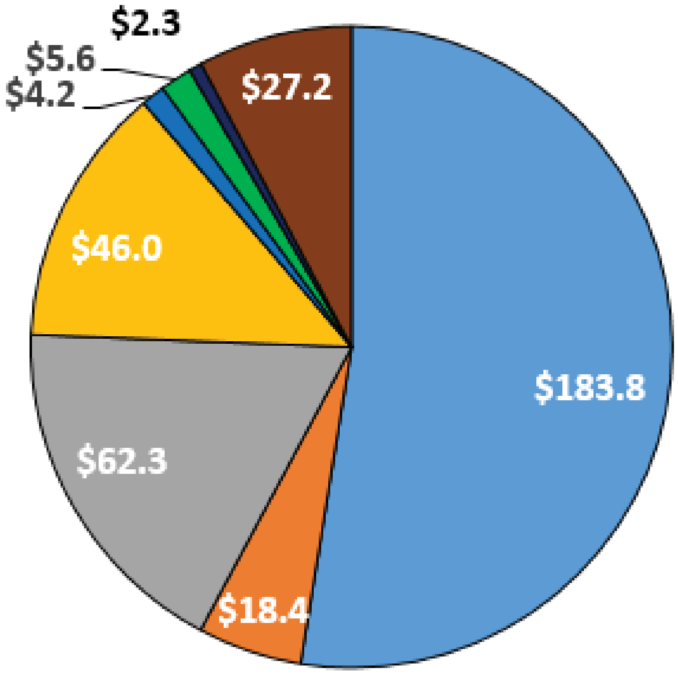
Change Management

Description	Original	Refined	Delta	Explanation
Capital				
Training	**$1.0M**	**$1.4M**	**$0.4M**	• Training development needs were reevaluated and refined.
O&M				
Training	**$0.0M**	**$0.9M**	**$0.9M**	• Training delivery costs were recategorized as O&M.
Total	**$1.0M**	**$2.3M**	**$1.3M**	

Contingency

Description	Original	Refined	Delta	Explanation
Capital				
Contingency	**$34.2M**	**$27.2M**	**- $7.0M**	• Contingency percentage was reduced from ~12% to ~9% to account for increased degrees of certainty.
Total	**$34.2M**	**$27.2M**	**- $7.0M**	

Refined gross AMS implementation costs are ~$350 Million for 2018 – 2022



Category	Capital	O&M	Total Nominal
Meters	$171.1	$12.7	**$183.8**
Network	$16.8	$1.6	**$18.4**
Information Technology	$52.1	$10.2	**$62.3**
Systems Integration	$46.0	$0.0	**$46.0**
Program Management	$4.2	$0.0	**$4.2**
Communications	$1.2	$4.4	**$5.6**
Change Management	$1.4	$0.9	**$2.3**
Contingency	$27.2	$0.0	**$27.2**
Total	**$320.0M**	**$29.8M**	**$349.8M**

BUSINESS CASE BENEFITS

AMS benefits comparison –original vs. refined business case

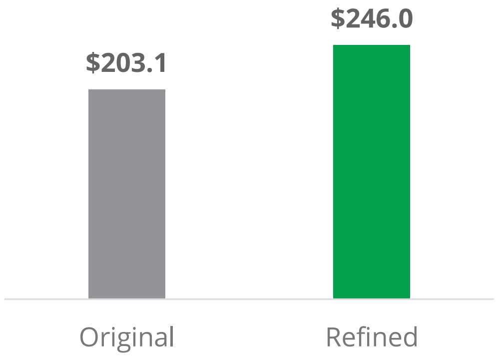
Total delta in benefits: - $34.2M

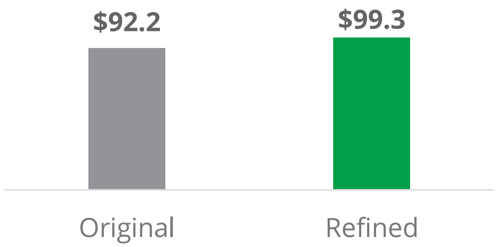
AMS benefits comparison – original vs. refined business case

Category	Original	Refined	Delta
Meter reading	$203.1	$246.0	$42.9
Meter services	$92.2	$99.3	$7.1
Avoided meter capital	$37.4	$55.6	$18.2
Avoided IT capital	$20.0	$11.8	-$8.2
Avoided distribution asset costs	$0.8	$0.8	$0.0
Avoided outage management costs	$4.5	$4.6	$0.1
Avoided "OK on arrival" costs	$6.9	$7.1	$0.2
ePortal benefits	$166.3	$158.1	-$8.2
Recovery of non-technical losses	$488.6	$402.3	-$86.3
Total	**$1,019.8M**	**$985.6M**	**-$34.2M**

Meter Reading & Meter Services

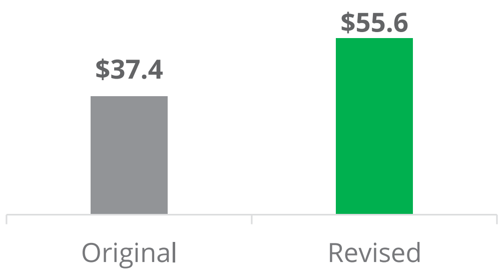
Description	Original	Refined	Delta	Explanation
Meter reading	**$203.1M**	**$246.0M**	**$42.9M**	• Reflects the compounded growth rate of labor due to shift in project timeline. • Included projected meter reading contract cost increase. • Updated PSC inspection needs to align to revised deployment and regulations. • Updated escalation assumption to align to contract labor escalations.
Meter services	**$92.2M**	**$99.3M**	**$7.1M**	• Reflects the compounded growth rate of labor due to shift in project timeline. • Reflects re-sequenced system installation and meter deployment plan
Total	**$295.3M**	**$345.3M**	**$50.0M**	

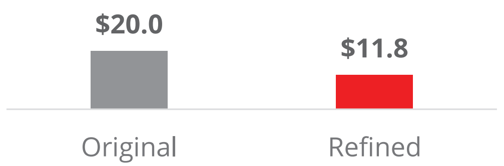




Avoided Meter & IT Capital

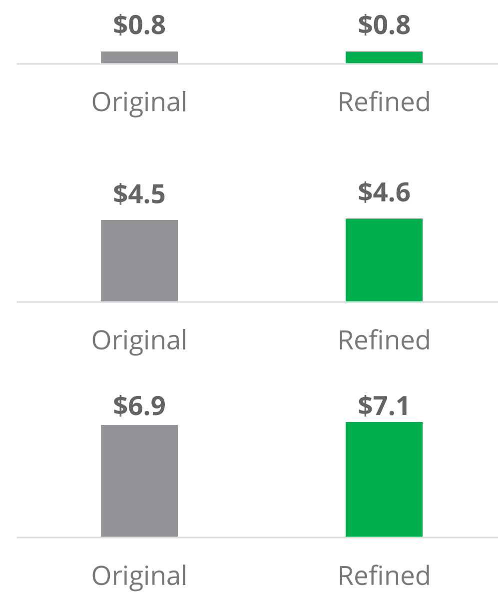
Description	Original	Refined	Delta	Explanation
Avoided meter capital	**$37.4M**	**$55.6M**	**$18.2M**	• Revised life of project from 2039 to 2040 to reflect the change in AMS program timing.
Avoided IT capital	**$20.0M**	**$11.8M**	**- $8.2M**	• Timing of IT infrastructure and systems projects changed due to the delay of the AMS program.
Total	**$57.4M**	**$67.4M**	**$10.0M**	





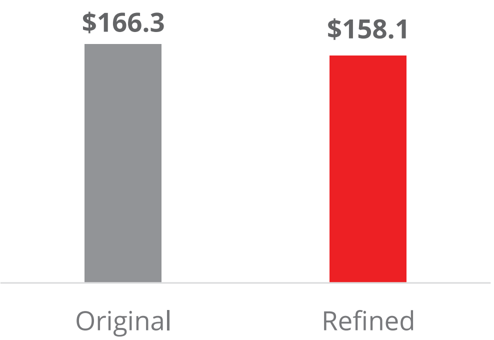
Avoided distribution, outage, and “ok on arrival” costs

Description	Original	Refined	Delta	Explanation
Avoided distribution asset costs	**$0.8M**	**$0.8M**	**$0.0M**	• N/A
Avoided outage restoration costs	**$4.5M**	**$4.6M**	**$0.1M**	• Revised life of project from 2039 to 2040 to reflect the change in AMS program timing.
Avoided “ok on arrival” costs	**$6.9M**	**$7.1M**	**$0.2M**	• Revised life of project from 2039 to 2040 to reflect the change in AMS program timing.
Total	**$12.2M**	**$12.5M**	**$0.3M**	



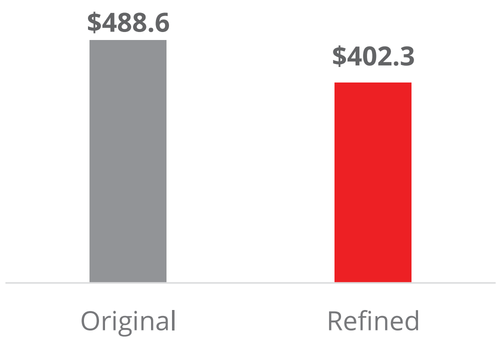
ePortal

Description	Original	Refined	Delta	Explanation
ePortal	**$166.3M**	**$158.1M**	**- $8.2M**	• Revised life of project from 2039 to 2040 to reflect the change in AMS program timing. • Updated Companies' revenue projections and average customer bill based on outcomes of latest rate case. • Removed 0.8% of in-scope customers to account for estimated opt-out.
Total	**$166.3M**	**$158.1M**	**- $8.2M**	



Recovery of non-technical losses

Description	Original	Refined	Delta	Explanation
Recovery of non-technical losses	**$488.6M**	**$402.3M**	**- $86.3M**	• Revised life of project from 2039 to 2040 to reflect the change in AMS program timing. • Updated Companies' revenue projections and average customer bill based on outcomes of latest rate case. • Removed 0.8% of in-scope customers to account for estimated opt-out.
Total	**$488.6M**	**$402.3M**	**- $86.3M**	



AMS Cost-Benefit Summary – nominal

Nominal Costs	Original Value	Refined Value
	2016-2039	2018-2040
Total project costs – capital	$320.4M	$320.0M
Total project costs – O&M	$30.0M	$29.8M
Total project costs	**$350.4M**	**$349.8M**
Total recurring costs – capital	$25.5M	$43.8M
Total recurring costs – O&M	$135.3M	$108.9M
Total recurring costs	**$160.8M**	**$152.7M**
Meter Retirement	**$39.7M**	**$0.0M**
Total lifecycle costs	**$550.9**	**$502.5M**

Total lifecycle costs delta **- $48.4M**

Nominal Benefits	Original Value	Refined Value
	2016-2039	2018-2040
Operational benefits	$364.9M	$425.2M
ePortal benefits	$166.3M	$158.1M
Recovery of non-technical losses	$488.6M	$402.3M
Total project benefits	**$1019.8M**	**$985.6M**
Total lifecycle benefits	**$1,019.8M**	**$985.6M**

Total lifecycle benefits delta **- $34.2M**

Refined net lifecycle costs (-) / benefits (+) $483.1M (nominal)

Project NPVRR Summary

Net Present Value of Revenue Requirements (NPVRR) is the current value of the revenue required by the utility to fully recover the cost of the project.

Original	Refined
2016-2039 **$30MM favorable to customer**	2018-2040 **$28.5MM favorable to customer**

What Changed

- **ROE** decreased from 10.23% to 9.7%, per the 2016 Rate Case.
- Project **timeline** has shifted: time-value of money is influenced by when the expenses are incurred.
- **Regulatory asset** for removed meters is not included in calculation of project NPVRR because a 15-year amortization schedule is assumed instead of 5-year amortization schedule, which coincides with the remaining book life of the removed meters and is in line with the Intervenor comments from the 2016 Rate Case.
- Included **recurring capital costs** associated with replacement of meters and network equipment to account for potential equipment failures.
- Reduced **recurring O&M costs** associated with web portal license fees to align with the participation assumptions in the ePortal benefits calculations.

OPT-OUT REVIEW

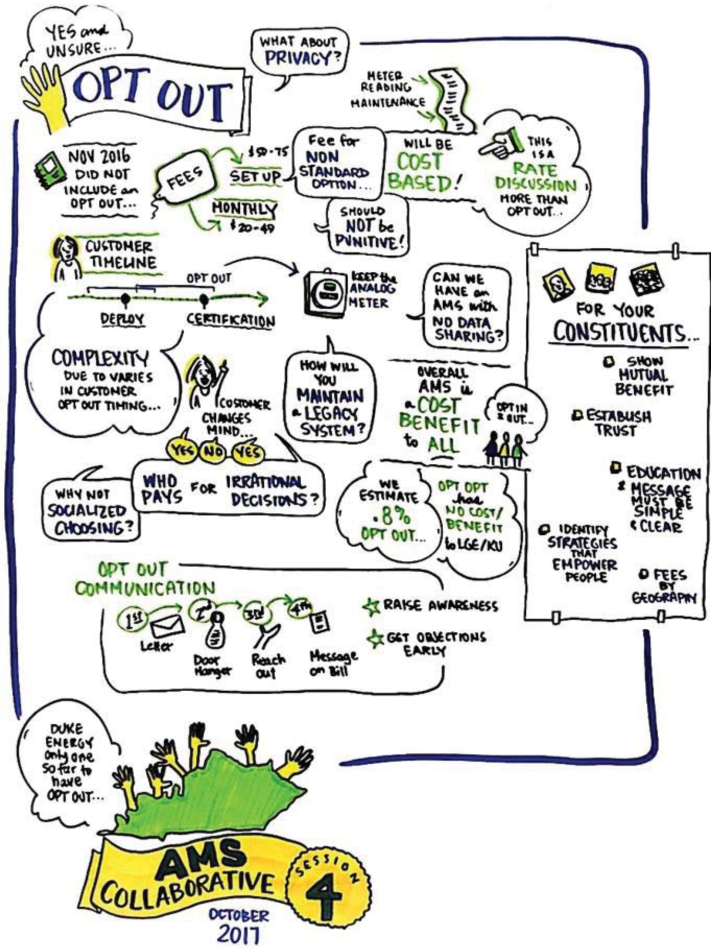
Review of opt-out discussion

Opt - out	Deployment	Opt - out	Certification	Manual meter reading

Description	Set-up fee	Monthly fee
Customers who opt-out of the AMS program would incur the costs associated with maintaining a non-standard option; including manual reading costs, system costs to support manual reads, meter costs, etc..	Yes	Yes

Summary of Session 4 discussion

- Mixed opinions on desire for and perception of an opt-out program.
- Discussed complexities associated with programmatically managing opt-outs (e.g. timing during deployment, changes between customers).
- The Companies must provide additional detail around what costs are included in the opt-out fees.
  - Fees should be cost-based, and should not be punitive in any way.



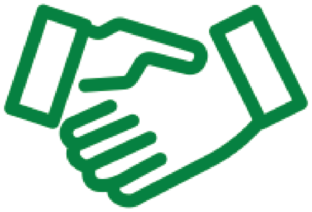
Opt-out program fees

Fee	Includes	LG&E Electric	LG&E Gas	LG&E Combo	KU
Set-up	• **Meter Reading Work Orders:** Cost to create initial work orders for meter exchange and optimize manual meter read routing. • **Field Services:** Costs to travel to customer premise, remove existing meter and replace with non-communicating meter, close work orders, plus transportation costs per contract account. • **Enrollment:** Customer Service Representative will take calls for opt-out customers, explain tariffs details, and set up account. Cost per contact account.	$50 - $60	$50 - $60	$65 - $70	$70 - $75
Monthly	• **Meter Reading System:** Cost to modify existing software system. Cost to annually upgrade existing software system. The software license costs which must be renewed each year. • **Meter Reading Equipment:** Cost of handheld and equipment maintenance/replacement. • **Meter Readers:** Ongoing costs for meter readers, dispatchers, and supervisors, plus transportation costs per contract account. Costs of manual off-cycle meter reads necessary due to inability to perform Remote Service Switch Services for non-AMS meters (bill complaints, re-reads), plus transportation costs. • **Field Services:** Costs of manual off-cycle meter reads necessary due to inability to perform Remote Service Switch Services for non-AMS meter (bill complaints, re-reads, move-in/move-out re-reads), plus transportation costs. • **Meter Costs:** Cost of legacy electric meters in inventory. • **Mesh Network:** Cost of additional relays, access points, and supporting infrastructure, assuming an even distribution of lost endpoints throughout the territory. Ongoing maintenance costs. • **Enrollment, Billing, and Reporting:** Updates to billing system to handle opt-out enrollment, training for staff, and testing. Updates to billing system to handle opt-out billing and reporting, training for staff, and testing.	$20 - $25	$20 - $25	$40 - $49	$30 - $35

GALLERY WALK

NEXT STEPS

THANK YOU



AMS Collaborative
November 8 Session Summary

Exhibit DEH-5
Page 39 of 43
Huff

AMS Collaborative Session #5 – Logistics

Wednesday, November 8, 2017
9:00 AM – 5:00 PM ET
Fairfield Inn and Suites, Frankfort, KY

Collaborative Objectives:

- Identify and discuss participants' interests regarding AMS
- Seek to address participant interests and questions

Session #5 Objectives:

- Review costs/benefits changes from previous business case
- Share additional information associated with Opt-out program fees
- Encourage discussion and questions to clarify updated information

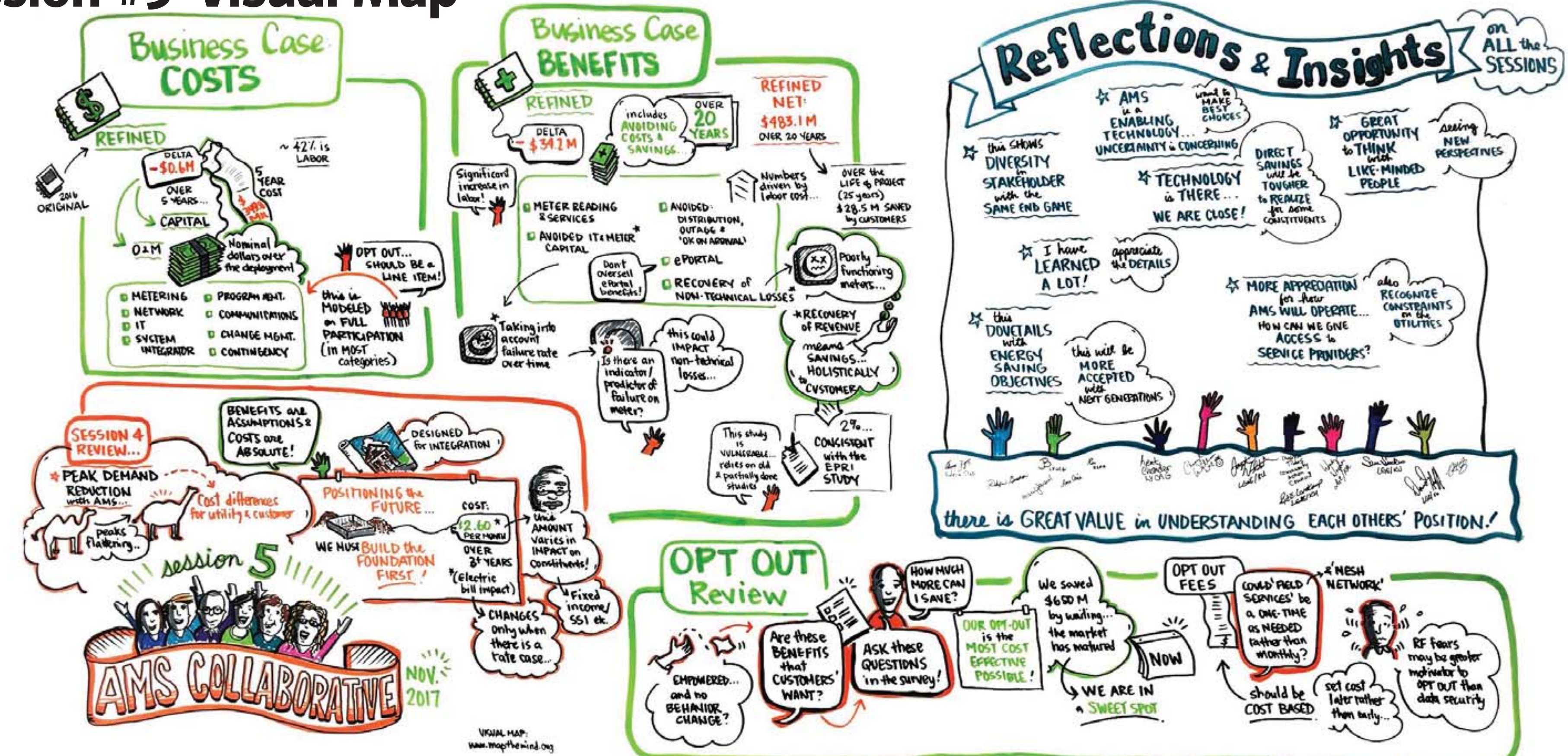
PARTICIPANTS

Participant	Organization
James Bush Richard Dugas	LFUCG
Kent Chandler	AG
Cathy Hinko	MHC
Marlon Cummings Lisa Kilkelly	Association of Community Ministries
Melissa Tibbs	CAC
Ron Willhite	KSBA
Barry Zalph	Sierra Club
David Huff Wendy Wagoner Lora Aria Rick Lovecamp Sara Judd Jonathan Whitehouse Samantha Stickler Cheryl Williams Joni Votaw	LG&E / KU
Jamie Hart Phyllis Goodson Maria Ferreira-Cesar	Accenture
Julie Gieseke	Accenture / Map the Mind

AGENDA

Topic	Time	Host
Safety Moment, Agenda, Session 4 Review, and Framework of Session 5	9:00 AM	Phyllis Goodson / David Huff
Business Case Costs	9:45 AM	Lora Aria
Break	10:45 AM	
Business Case Costs (continued)	11:00 AM	Lora Aria
Business Case Benefits	11:30 AM	Lora Aria
Lunch	12:30 PM	
Business Case Benefits (continued) and Summary	1:00 PM	Lora Aria
Break	1:45 PM	
Opt-Out	2:00 PM	Wendy Wagoner
Gallery Walk	2:30 PM	David Huff
Next Steps	3:15 PM	David Huff

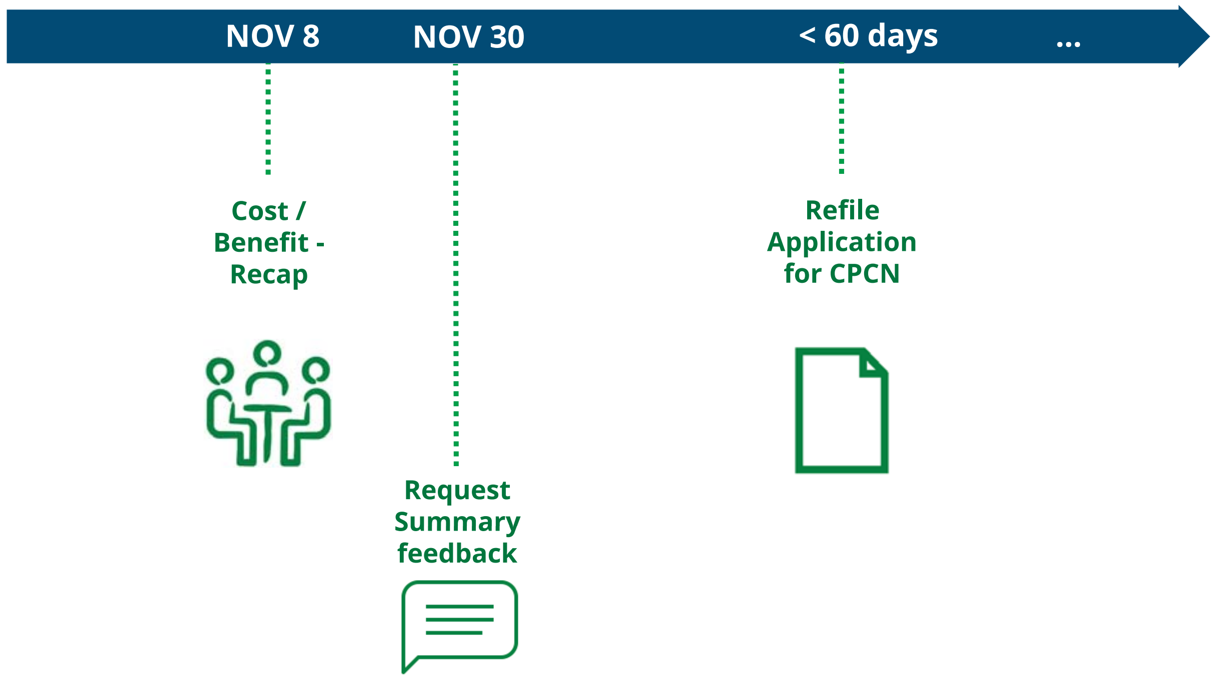
AMS Collaborative
Session #5 Visual Map



Next Steps

- David Huff is requesting Collaborative participants to review and edit the Collaborative summary document

- LG&E and KU plan to refile application of CPCN within the next 60 days. The revised business case and narrative includes updates since the November 2016 filing and input derived from Collaborative discussions.



Action Items

- Collaborative participants
  - Please review and edit the Collaborative summary document
    - Document to be shared by 11/17/2017. Suggest all response and edits to be returned by EOD 11/30/2017.
  - Please provide feedback to the animated video and communications discussed in the Collaborative meeting and listed below. Direct feedback to David Huff and Phyllis Goodson.
    - Demand Conservation - Animated Video Link
    - Early AMS Adoption – Video Link KU Branded

LG&E-KU AMS Collaborative Summary

The AMS (Advanced Metering Systems) Collaborative was formed as a result of the stipulation and recommendation agreement in LG&E and KU's (collectively "Companies") 2016 rate cases (collectively "rate case"). The stipulation and recommendation agreement limited participation in the AMS Collaborative to those who participated in the rate case. The Companies extended an offer to all rate-case participants. There were sixteen intervenors in the rate case; nine elected to fully participated; three elected to not attend meetings but receive all meeting minutes; and four declined participation. Below are the rate-case participants who elected to fully participate in the AMS Collaborative sessions.

Organizations	Representatives
Attorney General	Kent Chandler Rebecca W Goodman
Community Action Council	Melissa Tibbs
Kentucky Industrial Utility Customers	Kurt Boehm
Kentucky School Board Association	Ron Willhite
Lexington-Fayette Urban County Government	Richard Dugas James Bush
Louisville Metro Government	Cecil Goins Chris Seidt Edward Blayney Grace Simrall Mark Zoeller
Metropolitan Housing Coalition	Cathy Hinko Tom Fitzgerald
Sierra Club	Matthew Mueller Wallace McMullen Barry Zalph
The Association of Community Ministries	Eileen Ordover Lisa Kilkelly Marlon Cummings

Additionally, those listed below decided to receive the meeting minutes only.

Organizations	Representatives
AT&T	John T. Taylor Tony Taylor
Kroger	Rob Moore
Walmart	Carrie Harris Greg Tillman

Below is the list of those rate-case participants that elected not to participate in the Collaborative meetings.

Organizations
JBS Swift & Co
Kentucky League of Cities
Kentucky Cable Telecom Association
US Department of Defense

The Collaborative held five sessions from July 18, 2017, through November 8, 2017, to discuss a variety of issues around AMS. The table below shows the meeting date, location, and general themes of the discussion. The Companies drafted this document to summarize those meetings, the discussion, and the collaboration from the roughly 40 hours of discussion. The Companies invited participants to submit changes, and have attempted to incorporate those changes into this document to better reflect the work of the Collaborative over its five meetings. This document does not purport to be a verbatim transcript of the Collaborative meetings; by necessity, it does not and cannot contain all items discussed or points raised. Bullet points listed under the “Insights” headings are insights as described by the Companies as revised in accordance with edits and comments received from the participants, but they do not necessarily reflect the views of all participants. The Collaborative participants represent diverse constituencies and did not necessarily agree on all of the conclusions described in this document. Use of the word “participants” does not mean “all participants.”

Meeting Date	Meeting Location	Theme
Session 1 - July 18	KU Office at One Quality, Lexington	Determine topics for discussion from participants interests and concerns
Session 2 - August 22	Noah's Event Venue, Louisville	LG&E-KU Rate Case AMS Cost/Benefit Review - Baseline
Session 3 - September 20	Kentucky Chamber of Commerce, Frankfort	Data Privacy/Sharing, Data Empowerment, and Customer Education
Session 4 - October 17	Kentucky Chamber of Commerce, Frankfort	Opt-out, Remote Service Switch, New Services enabled by AMS
Session 5 - November 8	Fairfield Inn & Suites, Frankfort	Revised AMS Business Case changes Review and next steps

Learnings from the Collaborative

As stated in the stipulation and recommendation agreement, the purpose of the AMS Collaborative was to allow interested rate-case participants to discuss concerns about AMS and to seek to address them.

The Collaborative held its first meeting on July 18, 2017, in Lexington, Kentucky. After the initial meeting, the group met monthly in Louisville or Frankfort to maximize attendance and participation. The Companies designed the meetings to facilitate discussion between all participating members, including the Companies’ representatives. A visual facilitator supported each meeting and captured discussion and output of group exercises. Additional details of these sessions are captured in the presentations, meeting minutes provided as presentations, and the visual illustrations. Each session is summarized below.

Session 1

Collaborative participants divided into small work groups and responded to a series of questions to identify their concerns, needs, and questions specific to AMS and the Companies' filing from November 2016. Discussion topics from the smaller groups were shared with the full group, sparking additional discussion and defining topics for future meetings. As similar themes arose, the Companies clustered topics together. Collaborative participants selected the following key themes for further exploration in later sessions:

- Costs: E.g., will the benefits justify the costs? How did the Companies get to the costs and benefits for AMS, and how will they impact customers? Are low-income customers paying more? Will new rates be a part of AMS? Will costs of supplemental equipment needed to implement energy savings (e.g. programmable thermostats) be a barrier to savings?
- Data Privacy / Sharing: E.g., who can access the collected data? Can the system be hacked? Will customer information be shared with others?
- Data Empowerment: E.g., what will the data be used for? Who can use this data? How can low income customers with less access to technology benefit from AMS enabled data?
- Education: E.g., what information will be shared with customers about AMS prior to implementing? How will the installation go? What is the communication plan to customers? How can the "digital divide" be addressed?
- Remote Service Switch: E.g., will more customers be disconnected once the system is running with a remote service switch? How can concerns about the loss of human intervention and the need for additional protections be addressed?
- New Services: E.g., what other services can be provided based on the data provided through AMS?

Participants were asked to sequence the general themes and agree upon the order in which the Collaborative would address these topics in future sessions. The group agreed on the following order and estimated time needed for the first four monthly meetings:

Cost Benefit Baseline - Full day

Data Privacy/Sharing - ½ day

Data Empowerment - ½ day

Education - ½ day

Remote Disconnect/Reconnect - ½ day

New Services - ½ day

Cost Benefit Recap - ½ day

Over the course of the Collaborative, the Companies suggested changes to the above schedule and timeframes, resulting in the following schedule.

- Session 1 – Identifying topics and sequencing
- Session 2 – Review of the Business Case from the November 2016 filing
- Session 3 – Data Privacy / Sharing, Data Empowerment, and Customer Education
- Session 4 – Opt-Out, Remote Service Switch, and New Services
- Session 5 – Review of Business Case changes

Session 1 Insights included:

- Participants discovered that the issues surrounding AMS were complex and very much interrelated. Some commented that the visual illustration really helped them connect and understand the interrelatedness of the various pieces of full deployment issues.
- As participants shared their specific positions on different aspects of an AMS program, they gained greater understanding of how their various positions might align or conflict.
- The dynamic identified between data privacy and data use was more complex than the AMS Collaborative participants initially realized.

Session 2: Review of Business Case (November 2016)

Session 2 began with an AMS introduction reviewing the steps that the Companies had previously taken to implement various technologies and pilots, including PLC (power line carrier), Responsive Pricing pilot, Downtown Network, and the Advanced Metering Systems program ("AMS Opt-In") offered to customers today as part of the Companies' demand-side-management and energy-efficiency programs. An overview of how an AMS system works, including physically seeing electric meters, gas modules, and communication hardware, provided participants with a common baseline of knowledge and terminology. A demonstration of the current ePortal "MyMeter" highlighted the capabilities associated with the AMS Opt-In that are available today.

Collaborative participants asked numerous questions surrounding the business case in the first meeting. The Collaborative thoroughly reviewed both the costs and benefits as published in the November 2016 filing. Cost categories included technical descriptions and details per category for both capital and O&M spend. Questions ranged from the total number of smart meters installed in the United States to the average book life of meters that are to be retired. Some participants questioned the validity of the Companies' assumptions and estimates of costs and benefits.

Session 2 Insights included:

- General Understanding: It was helpful to explain the operations and equipment of the AMS System to provide a baseline for understanding and communication. Additionally it was helpful to understand how AMS provides services that are complimentary to other company systems such as distribution automation without being duplicative.
- ePortal: The demo of the ePortal "MyMeter" created a foundational understanding of the data captured and how customers may use the information to empower decisions. ePortal savings are based upon engagement from AMS opt-in customers and validated through a third party study from TetraTech. The participants questioned the overall assumptions surrounding usage: 48% of residential electric customers would use the portal at least once; 36% of those would use it use it more than six times thus becoming active users (48% x 36% = 17%); and active users (17% of residential customers) would save 3% of their total bill. The 3% was discounted from

between 5% - 10% stated in an external report. Consequently, the final ePortal factor becomes 0.5% (17% x 3%). Participants expressed their thoughts that both the 17% and the 3% should be reduced. The Companies took the position that the reduction on the energy savings side (using 3% instead of anywhere between 5% and 10% represented in the external report) that results in an overall 0.5% factor is sufficient to account for both participation and energy savings bias from the opt-in program.

- Business Case: The detailed explanation of what was in each cost and benefit category improved the understanding of the business case. Participants did not agree on all categories, costs, or benefits associated within these categories, but through open discussions they understood the basis for the financials associated with the AMS program. One participant commented that the engineering assumptions in the business case are overall reasonable.
- Education: Participants discussed the impact of customer education on this type of project, and the complexities for changing usage behaviors associated with customer savings.
- Non-technical losses are difficult to track because with a utility, many things are changing at once, making it impossible to monitor non-technical losses in isolation from the other naturally occurring changes in a utility.

Session 3: Data Privacy / Sharing, Data Empowerment and Customer Education

The discussion of data security, privacy, and sharing began with a high-level overview of the technologies, processes, and practices in place today that support the Companies' corporate information security strategy and privacy policies. The AMS network and devices employ security at all communication levels and include message authentication. Privacy is of paramount importance across the organization, and customer information is only provided on an as-needed basis even between departments within the utility. Customers can enable access for third parties through defined processes, or provide their usage data directly to third parties through exports from "MyMeter." A demonstration of the Low-Income Portal, a channel for advocates to assist low-income customers with financial support, provided participants insight into the security and privacy measures that the Companies use today to support customer information sharing with external groups. Additionally, the group discussed the potential value of low income advocates having their client consumption data to assist with low income issues.

Participants raised concerns relating to data privacy policies being established solely by the Companies without external oversight or review. It was highlighted that outside groups are developing guidelines and standards that the Companies could leverage to increase consumer confidence.

In addition, a participant suggested that consumer data, including anonymous data, may offer the Companies new revenue opportunities. The participant suggested such revenues could be used to offset costs to customers associated with AMS.

A small group exercise asked participants to suggest solutions to challenges that various populations may have in accessing AMS data (e.g., low income customers who have less access to technology and seniors who may need caregiver assistance).

The Data Empowerment session compared monthly usage shared today through the customer bill to the more granular interval data available through an AMS system and portal. Some participants saw value in having more granular usage data and how that could empower users to change behaviors to save money. Combining changes in usage with notifications based on user defined thresholds could turn captured analytics into actionable outcomes.

During the Customer Education discussion, the presenter shared the phased approach the Companies would execute to inform and educate customers on the benefits, changes, and choices that will come with AMS, building both general awareness and energy literacy. The Companies' customer education programs leverage past experience and best practices with transformational projects, and use a multi-channel approach to measure awareness, engagement, and change.

Session 3 Insights included:

- Data Security/Privacy: Participants are more aware of security measures taken today, and understand that the utility does not sell/share customer data today.
- Data Access: Digital access (internet) to 15 minute interval energy consumption is a big enabler of providing customers with insights into their energy consumption, the benefits of making investments in energy saving appliances, or changing their behaviors. There may be third parties and programs that can assist customers in evaluating ways to save energy and money. In addition, there will be many ways to have "indirect" access to the usage data so customers lacking direct internet access can still have the opportunity to achieve benefits through AMS, such as accessing the information through phones, tablets, or public computers. Some participants believe "Green button-Connect my data" is a requirement to achieving third-party engagement for ePortal savings. The Companies are not averse to providing this service in the future after full-deployment, but propose that the cost of providing the service be evaluated against the number of third-party providers who use "Green button-Connect my data" to "connect" a customer's consumption data to their energy saving services or programs .
- Data Use/Empowerment: For some customer groups (e.g., low-income customers), information may not empower them, as they may not have the financial means to make larger changes.
- Data Use/Empowerment and Low Income Portal: The Companies discussed the value provided through using the Low Income Portal by Low Income Advocates/Groups to assist customers to make decisions on assistance.
- Data Use/Empowerment: Optional rate structures may drive beneficial behaviors. The Companies agree that optional rate structures may be beneficial in the future and a full AMS deployment will provide the information to evaluate alternative rate structures in the future. Some participants voiced their opposition to mandatory demand rates for all customers.
- Data Privacy/Data Empowerment: Some participants stated that their constituencies may oppose AMS for data privacy reasons, but may also want, and benefit from, services that require data to be collected. Participants inquired if data could be collected and then deleted so the utility would not store it. The Companies stated they are unaware of any other utility providing this kind of service and noted that the cost to program this kind of service is not in the business case.
- Consumer Education: Communication needs to be simple, program goals should communicate how to save money with AMS, and the program should address energy literacy from awareness to understanding, rather than focus only on deployment. Participants would have liked to see studies that promote behavior changes and adoption based on a defined education plan. The

Companies reference their success with customers in DSM programing and plan to use similar methods for AMS.

Session 4: Opt-Out, Remote Service Switch and New Services

Opt-out provisions were not included in the initial November 2016 filing based on Kentucky Public Service Commission Case No. 2012-00428 (Case 428). Case 428 referenced that opt-out provisions reduced the maximum benefits of AMS, and then later clarified that any additional costs incurred by a utility due to the impacts of an opt-out program should be borne by the individual customers choosing to opt out.

The Collaborative discussion of opt-out focused on Case 428 and recent rulings, including the addition of an opt-out option to the recent Duke Energy Kentucky proposal to deploy advanced metering across its Kentucky service territory, which the Commission approved. Communication, timing in the initial deployment, timing post-deployment, and fees brought light to the complexity of an opt-out program for both customers and the Companies.

Remote Service Switching discussions focused primarily on electric service. An overview of current practices educated Collaborative participants on current processes, including the 2016 percentage of disconnection service orders that resulted in disconnection, and on the changes that could come with Remote Service Switching. Participants voiced questions and concerns about various aspects of remote disconnections including: that low-income customers were likely to be disconnected in greater numbers; whether disconnections would be suspended during extreme temperatures; procedures when customers were still in process of obtaining assistance; protections for customers on oxygen or other medical devices; notification and timing. The Companies provided information on potential future processes. Participants discussed qualitative benefits related to service reconnections, flexibility with future move-in and move-out options, and the predictability of service disconnections and reconnections.

Session 4 Insights included:

- <u>Opt-out</u>
    - Based on the Kentucky PSC Case 2012-00428 (Case 428), the Companies did not include an AMS opt-out in their November 2016 business case. The Companies have included an opt-out solution in the current business case and plan to provide supporting language in the future filing. Some low-income advocates requested that opt-out costs be socialized across all customers. Based in-part on Case 428 and based on the principle of cost causation, the Companies' representatives advised that, those customers who choose to opt-out would be responsible for the costs associated with opting out, both on the one-time and recurring fees.
    - Participants had reservations about the one-time opt-out set-up fee discussed. There were concerns that the set-up fee could be an amount that was punitive. The Companies clarified that fees would only be cost-based. There were fewer concerns over monthly fees to cover cost associated with manual meter reading and maintaining required systems and processes. Some participants expressed interest in a special rate or tariff for those selecting to opt out.

- The Collaborative discussed the principle that customers electing to opt-out prior to having their legacy meter exchanged for AMS meter should not be required to pay the one-time set-up fee.

- <u>Remote Service Switch</u>
  - Participants preferred disconnections to occur over a time range (e.g., 9 a.m. to noon) rather than all at once (e.g., 10 a.m.) to manage agencies' office traffic and support. With more certainty in disconnection timeframes, some participants suggested additional communications for disconnections based on customers' communication preferences. As discussed with the Collaborative participants, the Companies' future plans and processes are to increase education and awareness on service disconnections and to consider providing notice of disconnects through a variety of communication means such as text messages, phone calls, and mail.
  - The Companies confirmed to participants that they have no plans to change their current practices or programs. They plan to use a temporary procedure that has manual review and human intervention components for an initial period to fine-tune any internal business logic and avoid unnecessary disconnections. More specifically, the Companies are not proposing any disconnection-related revisions to the tariff terms and conditions of service from implementing AMS.
  - Participants approve of more flexibility for reconnections during non-standard business hours which would benefiting all (e.g., disconnections for non-payment, new customers, move-in).
  - Participants appreciated that the Remote Service Switch would be used for customer-scheduled disconnections, e.g. move-outs, but suggested there should be a minimum wait time for disconnection to prevent abuse, e.g., domestic disputes.
- New services:
  - Suggestions included enhancements to the ePortal "MyMeter" and systems to receive near-real-time usage information. Another participant suggested allowing customers to provide access to their MyMeter usage data by a customer-selected service provider to enable identification of energy- and cost-saving opportunities. Programs and services to support usage data that enable property managers and builders to improve properties and support financing for improvements were suggested. Some suggested deployment of in-home devices (IHD) to display usage information; however, the Companies stated that, due to the limited amount of time customers leave the device activated on their counter, IHD deployment was not cost effective.
- Education: Information needs to be communicated in multiple formats to all users and different comprehension levels across the customer base. The Companies agreed and plan communications similar to the success it has had with DSM.

Session 5: Refined Business Case discussion

The key objective of Session 5 was to review any updates the Companies had made to the initial business case for full deployment of AMS and better understand the estimated bill impacts to the customer. Discussion began with addressing additional questions on topics in previous sessions.

Discussion continued with an illustrative view of the estimated AMS cost per month per residential electric customer in the first five years (the graph). Participants found the information helpful and relevant. Participants recognize that the graph, which depicts a $2 to $3 monthly residential cost per customer for an average electric residential customer, does not reflect rate cases or the timing of those rate cases, and thus does not identify when customers would actually experience bill increases to pay for AMS. The Companies agreed and stated that cost recovery is a rate case issue, not a Certificate of Public Convenience and Necessity (CPCN) Application issue, i.e., receiving CPCN approval for AMS deployment would not prescribe when or how the Companies would recover AMS costs; rather, cost-recovery issues would be addressed in subsequent rate proceedings.

Deployment costs from the initial business case decreased $.6 million from $350.4 million to $349.8 million over the projected five year view. Predominant changes to the business case by area included:

- Meters and Network- Numbers increased for both as quantities were refined and more network planning was done. Through vendor pricing negotiations, pricing per unit decreased but a more thorough network mapping resulted in increased equipment.
- Information Technology – Numbers decreased through refining software, hardware and labor costs.
- System Integrator – Estimated costs increased based on a more detailed scope and updated project timeline.
- Program Management – A small decrease resulted from refining the plan and moving some program management costs beyond the deployment years.
- Communications and Change Management – Costs were updated and aligned appropriately with O&M costs for the customer education plan and training.
- Contingency – The contingency percentage was reduced from 12% to 9% based on refining other costs for a savings of $7.0 million.
- Approximately 42% of costs are labor. Labor costs will likely continue to increase and have increased since the initial business case, causing the project cost to increase should it be delayed further.

A more conservative approach reduced benefits from $1,019.8 million to $985.6 million, resulting in a refined nominal AMS Cost-Benefit of $483.1 million over the life of the program. Areas of most interest included ePortal and non-technical losses, the benefits from which were reduced relative to the Companies' 2016 proposal.

Opt-out was revisited and then participants had the opportunity to review all five of the Collaborative Sessions illustrations created by the visual facilitator.

Clarifications to Session 4 provided during Session 5:

- Not knowing the number of customers who will opt-out shows the complexity of estimating costs for opt-outs and gaps in network coverage.
- Clarifications were provided specific to the current disconnection notice. The Companies provided assurances that processes specific to disconnections would remain the same after AMS deployment, with the exception of how disconnections physically occur. The current Medical Alert Program will remain intact.
- Safety for reconnections was discussed. Today, a customer must acknowledge receiving a safety notification if paying at an authorized agent. Participants recommended notifications continue or be enhanced.

Session 5 insights included:

- Participants were appreciative of the level of detail shared through the Collaborative. Participants suggest that AMS and the level of information provided will be more easily adopted with younger, technology-driven customers.
- New services will be the key to acceptance and recognition of greater benefits. Some participants stated that new services need to be developed more to better understand the need for the AMS deployment and appreciate cost versus benefits. Some believe that the most powerful new services will empower service providers to help customers rather than customers directly. Though the Companies agreed that there are many new services and programs that can be enabled by AMS, these new services were not included in the cost benefit analysis because data from AMS will be needed to economically evaluate each new service.
- Some participants expressed a new appreciation of both regulatory and engineering environments and constraints on the utilities.
- Collaborative participants suggested the use of animated video to help communicate complex topics and decisions for general awareness and contingency education. The Companies noted they had several already produced and agreed to send links to those videos to the participants for their review.
- Participants see AMS as an enabling technology. Some participants are unsure if they are willing to commit to AMS. They are not sure that the benefits outweigh the costs for their constituency.
- Consensus is that members feel customers just want to know, "What is it going to cost me?" The Companies attempted to answer this through the cost benefit review and the graph illustrating monthly cost per average retail residential electric customer.
- Collaborative members shared they would be interested in participating in an ongoing AMS working group if the Commission approves full AMS deployment.

Moving Forward

It is the Companies' intention that the next steps will include finalizing the CPCN application and related documents in preparation for submitting to the Kentucky Public Service Commission within the next 30 to 60 days. This is solely the Companies' intention and is not meant to reflect any support or disagreement from any Collaborative participants.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	
COMPANY AND KENTUCKY UTILITIES	**)**	
COMPANY FOR CERTIFICATES OF	**)**	**CASE NO. 2018-00005**
PUBLIC CONVENIENCE AND NECESSITY	**)**	
FOR FULL DEPLOYMENT OF ADVANCED	**)**	
METERING SYSTEMS	**)**	

TESTIMONY OF
RICK E. LOVEKAMP
MANAGER REGULATORY STRATEGY/POLICY
LG&E AND KU SERVICES COMPANY

Filed: January 10, 2018

Q. Please state your name, position, and business address.

A. My name is Rick E. Lovekamp. I am Manager of Regulatory Strategy/Policy for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. Please describe your educational and professional background.

A. A statement of my qualifications and work experience is attached as Appendix A.

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

A. Yes. I testified most recently in the Companies' most recent demand-side management and energy-efficiency program portfolio application proceeding, Case No. 2017-00441, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the origins of the Advanced Metering Systems ("AMS") Collaborative, the work of which David E. Huff explains in his testimony. Also, I address the Companies' existing policies concerning customer disconnections for non-payment and subsequent reconnections, which was a topic raised and addressed by the AMS Collaborative. Finally, I sponsor and explain the mechanics of the Advanced Metering Systems ("AMS") Opt-Out Special Charges tariff provisions.

Q. Are you supporting any exhibits to your testimony?

A. Yes, I am co-sponsoring with Mr. Huff the following exhibits to my direct testimony:

Exhibit REL-1	AMS Opt-Out Special Charges for KU (tariff provisions and cost support)
Exhibit REL-2	AMS Opt-Out Special Charges for LG&E electric (tariff provisions and cost support)
Exhibit REL-3	AMS Opt-Out Special Charges for LG&E gas (tariff provisions and cost support)

ORIGIN OF THE AMS COLLABORATIVE

Q. Please describe the origin of the AMS Collaborative.

A. In the Companies' 2016 base-rate cases, the Companies requested Certificates of Public Convenience and Necessity ("CPCNs") for the full deployment of AMS across their Kentucky service territories. As part of the First Stipulation filed in those cases, the Companies agreed to withdraw their requests for the Commission to grant CPCNs and to approve cost recovery for the proposed full deployment of AMS.[1] The First Stipulation specifically provided that the Companies' withdrawal of their requests would not preclude the Companies from proposing full AMS deployment in future proceedings.[2] The Companies further agreed in the First Stipulation to initiate an AMS Collaborative involving the Companies and all interested parties to the rate

[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Stipulation and Recommendation at 4 [First Stipulation] (Ky. PSC Apr. 19, 2017).

[2] *Id.*

cases to discuss any concerns about AMS.[3] The Commission approved the First Stipulation, with limited modifications that did not affect the AMS portion of the First Stipulation, on June 22, 2017.[4]

Mr. Huff describes the meetings and work of the AMS Collaborative in his testimony. As he explains, the group discussed a wide variety of topics concerning AMS, including how the Remote Service Switching capability of AMS might affect service disconnections and reconnections, particularly with regard to disconnections for non-payment. I address that issue below.

THE COMPANIES DO NOT PROPOSE TO CHANGE THEIR SERVICE DISCONNECTION AND RECONNECTION POLICIES

Q. What changes to the Companies' service disconnection and reconnection policies are the Companies proposing in this proceeding in connection with full AMS deployment?

A. The Companies are not proposing to change any of their service disconnection or reconnection policies due to AMS. As John P. Malloy describes in his testimony, one feature AMS will provide is the ability to remotely disconnect and reconnect electric service, called Remote Service Switching. (The Companies are not proposing to deploy Remote Service Switching for gas service.) I can assure the Commission and the Companies' customers that the Companies are not proposing to change their service disconnection or reconnection policies as a result of having Remote Service Switching capabilities.

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[3] *Id.*

[4] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Order (Ky. PSC June 22, 2017); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Order (Ky. PSC June 22, 2017).

Q. What is the Companies' policy regarding disconnection of service for non-payment?

A. The Companies' policy regarding disconnection of service for non-payment is fully set out in the Companies' tariffs, which the Companies do not propose to amend in this proceeding:

> Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.[5]

In addition, the Companies have been, and will continue to be, obligated to comply with the Commission's regulations concerning refusal or termination of service, particularly 807 KAR 5:006 Section 15.

Q. Do the Companies propose to modify or amend their cold-weather disconnection policies?

A. No. The Companies' cold-weather disconnection policy, which the Companies do not propose to change, is below:

> **Policy for Residential Disconnects During Periods of Cold Weather**

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[5] Kentucky Utilities Company, P.S.C. No. 18, Original Sheet No. 105.1; Louisville Gas and Electric Company, P.S.C. Electric No. 11, Original Sheet No. 105.1; Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 105.1.

> **Overview:**
>
> These guidelines apply only to residential disconnections for non-payment and do not apply to disconnections of unauthorized reconnects (UARs) or disconnections necessary due to other dangerous conditions. Louisville Gas and Electric Company will continue to disconnect UARs regardless of weather conditions because it cannot condone a practice that places the person performing the UAR at immediate risk of permanent injury.
>
> **Cold Weather Periods:**
>
> Non-payment disconnections should not be initiated when the National Weather Service (NWS) predicts a daily high temperature below 32 degrees for a 24 hour period. It is suggested that non-payment disconnections not occur on the last work day of the week when the weekend forecast calls for temperatures that fall below 32 degrees. In addition, disconnections may be suspended during the work day should temperatures abruptly drop below the original NWS forecast.

As is true for service disconnections generally, the Companies will continue to comply with the Commission's regulations concerning winter hardship reconnection of service, particularly 807 KAR 5:006 Section 16.

In short, the Companies are proposing absolutely no changes to their policies regarding service disconnection and reconnection. The only practical change will be that electrical service disconnections and reconnections will be done remotely for AMS-equipped customers, improving the speed and reducing the cost of such services. And as Mr. Malloy notes in his testimony, Remote Service Switching has other benefits, including more rapid service reconnections when payments have been made, as well as potential safety benefits for customers and the Companies' personnel.

AMS OPT-OUT SPECIAL CHARGES

Q. Please describe the AMS Opt-Out Special Charges.

A. As shown in the tariff sheets attached to my testimony as Exhibits REL-1 (KU), REL-2 (LG&E electric), and REL-3 (LG&E gas), and as described in Mr. Huff's testimony, the AMS Opt-Out Special Charges will allow customers to request metering that does not utilize two-way communications. (As Mr. Huff notes in his testimony, customers' ability to opt out will be limited by the Companies' operational and safety requirements.) As shown in the KU AMS Opt-Out Special Charges, KU customers electing to opt out will pay a set-up charge and a recurring monthly charge related to ongoing costs of opt-outs, including meter reading costs. LG&E customers electing to opt out will pay similar charges, though there are different amounts for electric customers and gas customers. The table below summarizes the proposed per-meter charges:[6]

Utility Service	Opt-Out Set-Up Charge	Recurring Monthly Opt-Out Charge
KU	$72.71	$32.45
LG&E electric	$57.86	$22.70
LG&E gas	$57.86	$21.80

Q. Why and when will customers opting out of AMS be assessed opt-out charges?

A. As Mr. Huff discusses and supports in his testimony, and as shown in the cost support provided in Exhibits REL-1 (KU), REL-2 (LG&E electric), and REL-3 (LG&E gas), all of the opt-out charges the Companies propose are based on costs created by

[6] The only exception to applying opt-out charges on a per-meter basis concerns the small number of situations in which the Companies currently bill multiple meters on a combined basis for operating convenience. *See* Kentucky Utilities Company, P.S.C. No. 18, Original Sheet No. 101.1; Louisville Gas and Electric Company, P.S.C. Electric No. 11, Original Sheet No. 101.1; Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 101.1. The Companies will apply only one opt-out set-up charge and one monthly charge in each such situation. For expediency and overall clarity, the Companies refer to the opt-out charge as a per-meter charge throughout their application and testimony in this proceeding.

customers choosing to opt out of the AMS deployment. The set-up charge will cover all the costs associated with a meter that does not utilize two-way communications, e.g., system set-up and license fees for systems needed for the non-communicating meter, as well as costs to change the meter. The Companies propose that a customer pay the opt-out set-up charge for each meter the customer seeks to opt out. For example, if a residential customer opts out the meter at the customer's residence and pays the opt-out set-up charge, the customer will have to pay the charge again if the customer moves and seeks to opt out at the new residence. Also, because the Companies plan to replace an opted-out meter with an AMS meter when the customer who requested the opt-out ceases to take service for that meter (e.g., when a renter who has opted out a meter leaves that premise), each new customer that opts out a meter will be charged the opt-out set-up fee (i.e., if the next renter chooses to opt out, that customer will also pay the opt-out set-up fee).

But the Companies propose to have an initial period during which customers may request to opt out and avoid the set-up charge. If the Commission grants all relief requested in this application by June 1, 2018, the Companies propose to allow customers to request opt-out on or before the start of AMS meter deployment in their area without incurring the set-up charge. Any opt-out requested in a particular deployment area for any reason after the start of AMS meter deployment in that area will incur a set-up charge.

In addition to the opt-out set-up charge, the Companies propose to implement a recurring monthly opt-out charge that will take effect for all opted out meters within a particular deployment area following the full deployment of AMS in that particular deployment area and validation of the meter-data-management and related systems in that area. The recurring monthly charge will cover the cost of manual meter reading and billing, as well as the Companies' cost to keep an inventory of meters that do not utilize two-way communications.

The Companies believe this opt-out approach accords with the Commission's position in its final order in its 2012 administrative case on smart grid matters: "The Commission finds that any opt-out provision should require those customers that opt out to bear the cost related to that decision—through a one-time fee and/or a monthly charge, as appropriate."[7] In particular, the Companies' proposed opt-out charges align with the Commission's cost-based requirement.

Also, creating a disincentive to opting out, albeit one purely based on costs created by opting out, provides benefits to the vast majority of customers who will not opt out. As the Commission has recognized, a smart-meter deployment creates the greatest operational benefits relative to its costs if it is ubiquitous.[8] Mr. Huff discusses this further in his testimony.

Q. Has the Commission recently considered and approved a smart meter opt-out tariff?

A. Yes. In Case No. 2016-00152, the Commission recently considered Duke Energy Kentucky's ("Duke Kentucky") Electric AMI Opt-Out Program Tariff ("Rider AMO"). Rider AMO provides that a residential customer may opt out of AMI for one-time fee of $100 (post-deployment; there is not a one-time fee for those who opt out pre-deployment) and a $25 monthly charge. The parties reached a stipulation,

[7] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 17 (Apr. 13, 2016).
[8] *Id.*

which provided in relevant part that Duke Kentucky would implement Rider AMO. The Commission approved the stipulation on May 25, 2017.[9] The Companies' proposed AMS Opt-Out Special Charges are structurally similar to Duke Kentucky's approved Rider AMO, though the charges differ to reflect the Companies' costs of opt-outs. Though the Commission has previously expressed a general opposition to opt-outs,[10] the similarities of the Companies' opt-out proposal to the one the Commission recently approved for Duke supports the reasonableness of the Companies' proposed opt-out approach.

Q. What is your recommendation to the Commission?

A. As my testimony and the testimony of Messrs. Malloy and Huff demonstrate, full AMS deployment will provide net benefits to customers. Therefore, I recommend the Commission approve the Companies' requests for Certificates of Public Convenience and Necessity for the full deployment of AMS, the proposed AMS Opt-Out Special Charges, and all other requests.

Q. Does this conclude your testimony?

A. Yes.

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[9] *In the Matter of: Application of Duke Energy Kentucky*, Case No. 2016-00152, Order (Ky. PSC May 25, 2017).

[10] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies,* Case No. 2012-00428, Order at 17 (Apr. 13, 2016).

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Rick E. Lovekamp**, being duly sworn, deposes and says that he is Manager Regulatory Affairs/Tariffs for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Rick E. Lovekamp

Rick E. Lovekamp

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of January 2018.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

Rick E. Lovekamp
Manager Regulatory Strategy/Policy
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3780

Previous Positions

LG&E and KU Services Company and Louisville Gas and Electric Company

Manager Regulatory Affairs/Tariffs	2015 – 2017
Manager Regulatory Affairs	2006 – 2015
Manager Financial Systems	1998 – 2006
Manager Payroll	1997 – 1998
Acting Manager Payroll	1996 – 1997
Accounting Analyst III	1995 – 1996
Accounting Analyst II	1992 – 1995

S.B.S. Packaging Films, Inc.

Founding Partner	1991 – 1992

Illinois Power Company

Accounting Analyst	1989 – 1991

Education

Indiana University, Masters of Business Administration
Eastern Illinois University, B.S.B./Accounting

Kentucky Utilities Company
Electric Tariffs
Clean Version

Exhibit REL-1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: January 10, 2018

DATE EFFECTIVE: February 9, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;

3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;

4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Systems (AMS) meter; or T

5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

ADVANCED METERING SYSTEMS OPT-OUT CHARGE N

For each meter Customer elects to opt-out of AMS, Customer will be charged as follows:

Set-Up Charge	$72.71
Monthly Charge	$32.45

For meters being billed on a combined basis prior to opt-out (see Sheet No. 101.1), only one set-up charge and monthly charge will apply.

The set-up charge will not apply to Customers' meters opted out before the start of AMS meter deployment in the particular deployment area. The monthly charge will begin to apply for each opted out meter in the first billing cycle following Company's validation of the meter-data-management and related systems for the particular deployment area.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company
Electric Tariffs
Red-Line Version

Exhibit REL-1

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 45.1
Cancelling P.S.C. No. 18, Original Sheet No. 45.1

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

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Kentucky Utilities Company
Electric Tariffs
Supporting Calculations

Exhibit REL-1

Kentucky Utilities Company
AMS Opt-Out - Electric
Cost Justification

Opt-Out Costs - Keep Existing Meter

Category	Cost Type	Description	Unit Price/ Hourly Rate	Hours to Complete	Quantity/ Events	Cost
Meter Reading System	One-Time Capital	Cost to modify existing software system.	$ 33,439		1	$ 33,439
	Recurring Capital	Cost to annual upgrade existing software system.	$ 30,216		1	$ 30,216
	Annual	The software license costs which must be renewed each year.	$ 18,935		1	$ 18,935
Meter Reading Equipment	Annual	Cost of handheld and equipment maintenance/replacement.	$ 21,755		1	$ 21,755
Meter Costs	Recurring Capital	Cost of legacy electric meters in inventory.	$ 209,723		1	$ 209,723
Meter Readers	One-Time Fee	Cost to create initial work orders for meter exchange and optimize manual meter read routing.	$ 52.88	0.42	4,130	$ 90,995
	Annual	Ongoing costs for meter readers, dispatchers, and supervisors, plus transportation costs.	$ 42.39	0.67	49,560	$ 1,400,623
	Annual	Costs of manual off-cycle meter reads necessary due to inability to perform Remote Meter Readings Services for non-AMS meters (bill complaints, re-reads), plus transportation costs.	$ 38.72	1	17	$ 658
Field Services	One-Time Fee	Costs to travel to customer premise, remove existing meter and replace with non-communicating meter, close work orders, plus transportation costs.	$ 61.99	0.75	4,130	$ 192,024
	Annual	Costs of manual off-cycle meter reads necessary due to inability to perform Remote Meter Readings Services for non-AMS meter (bill complaints, re-reads, move-in/move-out re-reads), plus transportation costs.	$ 62.04	1	1,014	$ 62,913
Mesh Network	One-Time Capital	Cost of additional relays, access points, and supporting infrastructure, assuming an even distribution of lost endpoints throughout the territory.	$ 2,735		10	$ 27,547
	Annual	Ongoing maintenance costs.	$ 1,000		40%	$ 403
Enrollment, Billing, and Reporting	One-Time Capital	Updates to billing system to handle opt -out enrollment, training for staff, and testing.	$ 40,288		1	$ 40,288
	One-Time Fee	Customer Service Representative will take calls for opt-out customers, explain tariffs details, and set up account costs.	$ 4.18		4,130	$ 17,262
	One-Time Capital	Updates to billing system to handle opt -out billing and reporting, training for staff, and testing.	$ 40,288		1	$ 40,288
		Total				$ 2,187,071

Proposed Opt-Out Rate Structure
Opt-Out Customers Who Keep Their Existing Meter

		Contracts
1.	Number of targeted for AMS Replacement	516,224
2.	Percent Opt-Out	0.80%
3.	Estimated Customers Opt-Out	4,130
	One-Time Fee	
4.	Meter Readers	$ 90,995
5.	Field Services	$ 192,024
6.	Enrollment	$ 17,262
7.	One-Time Fee	$ 300,282
8.	One-Time Fee costs divided by All Opt-Out Contracts	$ 72.71
	One-Time and Recurring Capital Costs	
	5 Year Life	
9.	Meter Reading System	$ 63,655
10.	Enrollment, Billing and Reporting	$ 80,576
11.	One-Time and Recurring Capital Costs to be recovered	$ 144,230
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$ 34.92
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer [1]	$ 1.10
	15 Year Life	
14.	Meter Costs	$ 209,723
15.	Mesh Network	$ 27,547
16.	One-Time and Recurring Capital Costs to be recovered	$ 237,270
17.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$ 57.45
18.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer [2]	$ 0.98
19.	Total Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer (13 +18)	$ 2.08
	Annual Recurring Costs	
20.	Meter Reading System	$ 18,935
21.	Meter Reading Equipment	$ 21,755
22.	Meter Readers	$ 1,401,282
23.	Field Services	$ 62,913
24.	Mesh Network	$ 403
25.	Annual Recovery of on-going Costs	$ 1,505,288
26.	Monthly Recovery of Recurring Costs per Contract	$ 30.37
27.	Total Monthly Fee (19 + 26)	$ 32.45

[1] 5 year amortization rate including a return component
[2] 15 year amortization rate including a return component

Louisville Gas and Electric Company
Electric Tariffs
Clean Version

Exhibit REL-2

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: January 10, 2018

DATE EFFECTIVE: February 9, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
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3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Systems (AMS) meter; or T
5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

ADVANCED METERING SYSTEMS OPT-OUT CHARGE N

For each meter Customer elects to opt-out of AMS, Customer will be charged as follows:

Set-Up Charge	$57.86
Monthly Charge	$22.70

For meters being billed on a combined basis prior to opt-out (see Sheet No. 101.1), only one set-up charge and monthly charge will apply.

The set-up charge will not apply to Customers' meters opted out before the start of AMS meter deployment in the particular deployment area. The monthly charge will begin to apply for each opted out meter in the first billing cycle following Company's validation of the meter-data-management and related systems for the particular deployment area.

Louisville Gas and Electric Company
Electric Tariffs
Red-line Version

Exhibit REL-2

Louisville Gas and Electric Company

P.S.C. Electric No. 11, First Revision of Original Sheet No. 1
Cancelling P.S.C. Electric No. 11, Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

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3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Systems (AMS) meter; or T
5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

Deleted: Automatic

ADVANCED METERING SYSTEMS OPT-OUT CHARGE N

For each meter Customer elects to opt-out of AMS, Customer will be charged as follows:

Set-Up Charge	$57.86
Monthly Charge	$22.70

For meters being billed on a combined basis prior to opt-out (see Sheet No. 101.1), only one set-up charge and monthly charge will apply.

The set-up charge will not apply to Customers' meters opted out before the start of AMS meter deployment in the particular deployment area. The monthly charge will begin to apply for each opted out meter in the first billing cycle following Company's validation of the meter-data-management and related systems for the particular deployment area.

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Louisville Gas and Electric Company
Electric Tariffs
Supporting Calculations

Exhibit REL-2

Exhibit REL-2

Louisville Gas and Electric Company
AMS Opt-Out - Electric Only
Cost Justification

Opt-Out Costs - Keep Existing Meter

Category	Cost Type	Description	Unit Price/ Hourly Rate	Hours to Complete	Quantity/ Events	Cost
Meter Reading System	One-Time Capital	Cost to modify existing software system.	$ 26,780		1	$ 26,780
	Recurring Capital	Cost to annual upgrade existing software system.	$ 24,199		1	$ 24,199
	Annual	The software license costs which must be renewed each year.	$ 15,165		1	$ 15,165
Meter Reading Equipment	Annual	Cost of handheld and equipment maintenance/replacement.	$ 17,423		1	$ 17,423
Meter Costs	Recurring Capital	Cost of legacy electric meters in inventory.	$ 167,931		1	$ 167,931
Meter Readers	One-Time Fee	Cost to create initial work orders for meter exchange and optimize manual meter read routing.	$ 54.71	0.42	3,307	$ 75,386
	Annual	Ongoing costs for meter readers, dispatchers, and supervisors, plus transportation costs.	$ 45.55	0.42	39,684	$ 753,193
	Annual	Costs of manual off-cycle meter reads necessary due to inability to perform Remote Meter Readings Services for non-AMS meters (bill complaints, re-reads), plus transportation costs.	$ 40.60	1.00	9	$ 365
Field Services	One-Time Fee	Costs to travel to customer premise, remove existing meter and replace with non-communicating meter, close work orders, plus transportation costs.	$ 61.77	0.50	3,307	$ 102,138
	Annual	Costs of manual off-cycle meter reads necessary due to inability to perform Remote Meter Readings Services for non-AMS meter (bill complaints, re-reads, move-in/move-out re-reads), plus transportation costs.	$ 61.79	1.00	521	$ 32,193
Mesh Network	One-Time Capital	Cost of additional relays, access points, and supporting infrastructure, assuming an even distribution of lost endpoints throughout the territory.	$ 2,735		8	$ 22,061
	Annual	Ongoing maintenance costs.	$ 1,000		32%	$ 323
Enrollment, Billing, and Reporting	One-Time Capital	Updates to billing system to handle opt -out enrollment, training for staff, and testing.	$ 32,265		1	$ 32,265
	One-Time Fee	Customer Service Representative will take calls for opt-out customers, explain tariffs details, and set up account costs.	$ 4.18		3,307	$ 13,822
	One-Time Capital	Updates to billing system to handle opt -out billing and reporting, training for staff, and testing.	$ 32,265		1	$ 32,265
		Total				$ 1,315,508

Proposed Opt-Out Rate Structure
Opt-Out Customers Who Keep Their Existing Meter

		Contracts
1.	Number of targeted for AMS Replacement	413,424
2.	Percent Opt-Out	0.80%
3.	Estimated Customers Opt-Out	3,307
	One-Time Fee	
4.	Meter Readers	$ 75,386
5.	Field Services	$ 102,138
6.	Enrollment	$ 13,822
7.	One-Time Fee	$ 191,346
8.	One-Time Fee costs divided by All Opt-Out Contracts	$ 57.86
	One-Time and Recurring Capital Costs	
	5 Year Life	
9.	Meter Reading System	$ 50,979
10.	Enrollment, Billing and Reporting	$ 64,530
11.	One-Time and Recurring Capital Costs to be recovered	$ 115,509
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$ 34.93
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer [1]	$ 1.10
	15 Year Life	
14.	Meter Costs	$ 167,931
15.	Mesh Network	$ 22,061
16.	One-Time and Recurring Capital Costs to be recovered	$ 189,992
17.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$ 57.45
18.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer [2]	$ 0.97
19.	Total Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer (13 +18)	$ 2.07
	Annual Recurring Costs	
20.	Meter Reading System	$ 15,165
21.	Meter Reading Equipment	$ 17,423
22.	Meter Readers	$ 753,558
23.	Field Services	$ 32,193
24.	Mesh Network	$ 323
25.	Annual Recovery of on-going Costs	$ 818,661
26.	Monthly Recovery of Recurring Costs per Contract	$ 20.63
27.	Total Monthly Fee (19 + 26)	$ 22.70

[1] 5 year amortization rate including a return component
[2] 15 year amortization rate including a return component

Louisville Gas and Electric Company
Gas Tariffs
Clean Version

Exhibit REL-3

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

DATE OF ISSUE: January 10, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Special Charges

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

UNAUTHORIZED RECONNECT CHARGE

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

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ADVANCED METERING SYSTEMS OPT-OUT CHARGE N

For each meter Customer elects to opt-out of AMS, Customer will be charged as follows:

Set-Up Charge	$57.86
Monthly Charge	$21.80

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Gas Tariffs
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P.S.C. Gas No. 11, First Revision of Original Sheet No. 1
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Louisville Gas and Electric Company

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Louisville Gas and Electric Company
Gas Tariffs
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Exhibit REL-3

Louisville Gas and Electric Company
AMS Opt-Out - Gas Only
Cost Justification

Opt-Out Costs - Keep Existing Meter

Category	Cost Type	Description	Unit Price/ Hourly Rate	Hours to Complete	Quantity/ Events	Cost
Meter Reading System	One-Time Capital	Cost to modify existing software system.	$ 20,944		1	$ 20,944
	Recurring Capital	Cost to annual upgrade existing software system.	$ 18,926		1	$ 18,926
	Annual	The software license costs which must be renewed each year.	$ 11,860		1	$ 11,860
Meter Reading Equipment	Annual	Cost of handheld and equipment maintenance/replacement.	$ 13,626		1	$ 13,626
Meter Costs	Recurring Capital	Cost of legacy electric meters in inventory.	$ -		-	$ -
Meter Readers	One-Time Fee	Cost to create initial work orders for meter exchange and optimize manual meter read routing.	$ 54.71	0.42	2,587	$ 58,973
	Annual	Ongoing costs for meter readers, dispatchers, and supervisors, plus transportation costs.	$ 45.55	0.42	31,044	$ 589,208
	Annual	Costs of manual off-cycle meter reads necessary due to inability to perform Remote Meter Readings Services for non-AMS meters (bill complaints, re-reads), plus transportation costs.	$ 40.05	1.00	7	$ 280
Field Services	One-Time Fee	Costs to travel to customer premise, remove existing meter and replace with non-communicating meter, close work orders, plus transportation costs.	$ 61.77	0.50	2,587	$ 79,900
	Annual	Costs of manual off-cycle meter reads necessary due to inability to perform Remote Meter Readings Services for non-AMS meter (bill complaints, re-reads, move-in/move-out re-reads), plus transportation costs.	$ 61.77	1.00	408	$ 25,202
Mesh Network	One-Time Capital	Cost of additional relays, access points, and supporting infrastructure, assuming an even distribution of lost endpoints throughout the territory.	$ 2,735		6	$ 17,254
	Annual	Ongoing maintenance costs.	$ 1,000		25%	$ 252
Enrollment, Billing, and Reporting	One-Time Capital	Updates to billing system to handle opt -out enrollment, training for staff, and testing.	$ 25,234		1	$ 25,234
	One-Time Fee	Customer Service Representative will take calls for opt-out customers, explain tariffs details, and set up account costs.	$ 4.18		2,587	$ 10,813
	One-Time Capital	Updates to billing system to handle opt -out billing and reporting, training for staff, and testing.	$ 25,234		1	$ 25,234
		Total				$ 897,708

Proposed Opt-Out Rate Structure
Opt-Out Customers Who Keep Their Existing Meter

		Contracts
1.	Number of targeted for AMS Replacement	323,336
2.	Percent Opt-Out	0.80%
3.	Estimated Customers Opt-Out	2,587
	One-Time Fee	
4.	Meter Readers	$ 58,973
5.	Field Services	$ 79,900
6.	Enrollment	$ 10,813
7.	One-Time Fee	$ 149,686
8.	One-Time Fee costs divided by All Opt-Out Contracts	$ 57.86
	One-Time and Recurring Capital Costs	
	5 Year Life	
9.	Meter Reading System	$ 39,870
10.	Enrollment, Billing and Reporting	$ 50,468
11.	One-Time and Recurring Capital Costs to be recovered	$ 90,338
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$ 34.92
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer [1]	$ 1.06
	15 Year Life	
14.	Meter Costs	$ -
15.	Mesh Network	$ 17,254
16.	One-Time and Recurring Capital Costs to be recovered	$ 17,254
17.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$ 6.67
18.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer [2]	$ 0.11
19.	Total Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer (13 +18)	$ 1.17
	Annual Recurring Costs	
20.	Meter Reading System	$ 11,860
21.	Meter Reading Equipment	$ 13,626
22.	Meter Readers	$ 589,488
23.	Field Services	$ 25,202
24.	Mesh Network	$ 252
25.	Annual Recovery of on-going Costs	$ 640,429
26.	Monthly Recovery of Recurring Costs per Contract	$ 20.63
27.	Total Monthly Fee (19 + 26)	$ 21.80

[1] 5 year amortization rate including a return component
[2] 15 year amortization rate including a return component