STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

REQUEST FOR PERMANENT RATES

REBUTTAL TESTIMONY OF PENELOPE McLEAN CONNER

AMR Deployment and Customer Issues

On behalf of Public Service Company of New Hampshire

d/b/a Eversource Energy

March 3, 2020

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d/b/a EVERSOURCE ENERGY
REQUEST FOR PERMANENT RATES**

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I. INTRODUCTION

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

A. My name is Penelope McLean Conner. My business address is 247 Station Drive, Westwood, Massachusetts 02090. I am Chief Customer Officer and Senior Vice President of the Customer Group for Eversource Energy Service Company.

Q. What are your principal responsibilities in this position?

A. As Chief Customer Officer and Senior Vice President, I am responsible for overseeing all aspects of customer services, including planning and directing all activities related to the processes of customer inquiries, billing, credit and collections, and field operations, and also for delivering a cost-effective portfolio of energy efficiency programs to customers of the gas and electric companies of Eversource Energy ("Eversource"), including Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the

"Company"). I lead a team of 1,400 employees and manage a $120 million annual budget. I am testifying in this proceeding on behalf of PSNH.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On May 28, 2019, I submitted direct, pre-filed testimony on the Company's customer experience initiatives and introduced the Company's proposals for a "fee free" credit/debit card payment system and for implementation of an arrearage forgiveness program. My testimony also provided a discussion of the Company's 2013 project to transition to an automated meter reading ("AMR") system from the old mechanical manual meter system. My initial testimony included a description of my educational and professional background

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to several issues raised in the testimony of the Commission Staff, the Office of Consumer Advocate ("OCA") and others related to the Company's 2013 AMR deployment, as well as to issues raised regarding the Company's fee free proposal and New Start arrearage forgiveness proposal.

Q. Please provide an overview of your rebuttal testimony.

A. In Section II, I address the Company's AMR deployment, including the recommendation by Staff Witness Richard Chagnon to allow recovery of the Company's meter investments "subject to adjustments after a more detailed investigation of all meters and associated equipment (Account 370) and associated costs (e.g., IT upgrades) by Staff" (Chagnon Test., at 34). The Company appreciates this recommendation as the Company has presented substantial evidence demonstrating that the decision, at the time it was made, was the appropriate, cost-justified plan to address the approaching obsolescence of PSNH's legacy metering plant and to reduce operating cost. The Company recognizes that it took time for the Company to investigate, confirm and present information on the steps taken to account for meter-plant retirements and that Mr. Chagnon did not receive necessary information until just before Staff's testimony was due to be filed.

For this reason, the Company recognizes Staff's interest in further investigation of this issue. However, the record developed on this issue now contains the appropriate substantial evidence to support a final determination at this time that the Company's legacy meter investments were properly retired and accounted for; that the costs of the new AMR metering plant included in rate base was prudently incurred; and that the AMR metering plant is used and useful in the service of customers. Therefore, the Company is suggesting that there is a basis for concluding this issue in this case and the Company stands ready to provide any further explanation that may be necessary to accommodate this result.

The balance of Section II responds in detail to a number of false assertions and speculation by OCA witness Paul J. Alvarez that the Company did not demonstrate that its AMR deployment was necessary; should have pursued installation of retrofit "radio modules" as a least cost option; and, if it were to replace its meters, should have installed "industry standard technology," meaning advanced metering infrastructure ("AMI"), offering interval usage data available (Alvarez Test. at 5). My testimony demonstrates that the Company's AMR installation in 2013 enabled substantial operating cost savings and was necessary to replace a mechanical meter system approaching obsolescence, with almost one-third of the legacy meters at or beyond the 35-year depreciated lifespan, and almost 50 percent of the meters older than 20 years. Approximately 80 percent of the meter inventory was older than 10 years.

My testimony also discredits Mr. Alvarez's radio-module retrofit concept, showing that -- in 2013 -- this was not a viable option because these types of modules were not available in the market; would have been more costly than represented by Mr. Alvarez even if the units were available; and would have been operationally inferior, as demonstrated by industry experience.

Regarding AMI, my testimony demonstrates that AMI was not "industry standard technology" in 2013; was not a viable alternative to the Company's AMR project in 2013; and, in fact, would have cost in excess of $200 million to achieve the functionality espoused by Mr. Alvarez, as compared to the $38 million AMR installation – which seven years later remains the appropriate choice. The Company's AMR installation yielded quantifiable cost savings associated with the elimination of manual operations. Further, it was reasonable to move forward with the AMR initiative because it takes time for new rates to incent behavior and it was unclear at the time whether the ultimate solution could be more dynamic than time-varying rates ("TVR"). Today, Eversource can accomplish peak load reduction without TVR, and with the maturation of demand management programs, such rates are not necessary to support customer participation in these programs. Moreover, Mr. Alvarez's claims supporting AMI in this proceeding are in direct conflict with claims he has made opposing AMI in other jurisdictions.

In Section III of my testimony, I address several customer-related issues, including suggested modifications of the Company's fee free proposal and New Start arrearage forgiveness proposal by Staff witness Amanda Noonan (Noonan Test. at 2-3). PSNH appreciates the Staff's support of fee free and New Start and the constructive nature of Staff's recommendations. My testimony provides a brief response and path forward to address Staff's suggested modifications to these proposals. Regarding fee free, the recommendation to expand the program to include recurring payments remains problematic because it introduces the potential for larger than planned customer adoption, which would result in larger costs to be borne by rate payers. Regarding New Start, Staff makes a number of recommendations related to program implementation that the Company is open to discussing in an appropriate stakeholder process.

Lastly, Section III provides a brief response to several issues raised by Roger D. Colton on behalf of The Way Home, an intervenor in this proceeding, which proposes numerous modifications to the Company's New Start arrearage forgiveness proposal and also makes recommendations on service disconnections, customer communications, and deferred payment arrangements (Colton Test. at 5-8).

Q. Are you sponsoring any attachments through your rebuttal testimony?

A. Yes. The table below lists the attachments I am sponsoring through my rebuttal testimony:

Attachment	Description
Attachment-PMC-Rebuttal-1	Annual Meter Report, Year-Ending Sept. 1, 2012
Attachment-PMC-Rebuttal-2	Listing of Installed Meters by Purchase Year
Attachment-PMC-Rebuttal-3	2010 EPRI Report on the Accuracy of Digital Meters
Attachment-PMC-Rebuttal-4	Sensus Communication Regarding Radio Modules
Attachment-PMC-Rebuttal-5	Illustrative Cost Comparison of AMR to Radio Modules
Attachment-PMC-Rebuttal-6	AEP Ohio AMR Implementation
Attachment-PMC-Rebuttal-7	Article by Green Tech Media

II. AMR DEPLOYMENT

Q. Please describe Staff's recommendation related to the Company's meter investments.

A. Staff recommends allowing recovery of the Company's meter investments "(including all meter types—e.g., AMR, probe, AMR-bridge) *subject to adjustments after a more detailed investigation* of all meters and associated equipment (Account 370) and associated costs (e.g., IT upgrades) by Staff" (Chagnon Test. at 34) (emphasis added). Staff raises concerns regarding the level of information provided in my initial testimony and timing of the Company's discovery responses on this topic (Chagnon Test. at 33-34).

Q. Does the Company have a response to Staff's recommendation?

A. Yes. Again, the Company appreciates the reasoned approach demonstrated by Mr. Chagnon. If the Commission were to adopt Staff's recommendation to allow cost recovery subject to further investigation, the Company would certainly support Staff's investigation. However, the record evidence submitted by the Company on AMR (albeit coming late in the process in some cases, and in some instances required to clarify prior responses) is detailed and comprehensive and supports a final determination in this rate case that the

Company's meter investments are used and useful and the costs were prudently incurred. The 2013 AMR project was undertaken pursuant to a detailed business-case analysis that identified AMR with a drive-by data-collection system as the best option for customers based on information available at the time regarding cost, functionality and ease of integration with existing systems. As I explained in my initial testimony, the Company's guiding principle in making these types of investments is to adopt technologies that enable the Company to perform work more efficiently, more accurately, and at the lowest cost balanced with safety and reliability. The business-case analysis indicated that, once completed, PSNH would realize operational efficiencies and associated reductions in operating and maintenance ("O&M"), estimated at approximately $6 million per year, constituting a substantial upgrade in service for customers.

Q. What is the Company's concern with the Staff's recommendation?

A. It appears to the Company's that Staff's perspective is rooted, at least in part, in the notion that it had issued a "warning" to the Company that it would bear the burden of establishing the prudence of its AMR investment (Chagnon Test. at 32), although Staff agrees that pre-approval of these investments was not required (Eversource-Staff 4-007). Staff notes its concern that PSNH made its decision in 2013 to invest in AMR meters "incapable of adapting to future changes and the benefits of a smarter grid" (Chagnon Test. at 33), with the implication being that the Company should have waited to potentially deploy a different technology, such as AMI. However, seven years later, the State of New Hampshire has still not moved forward on grid modernization policies that would require AMI, and the timeline of potential developments in areas such as peak-demand reduction and TVR is uncertain. In fact, the New Hampshire energy efficiency plans are examining the demand management programs that Eversource has deployed in Massachusetts, which do not require AMI and work very well with the AMR system. Moreover, it is well-recognized that any implementation of full-scale AMI will require the development and completion of a thorough cost-benefit analysis evaluating a range of hard-to-quantify benefits, which would be subject to discussion and debate with key stakeholders. This is a process could take several years and is not yet commenced.

Conversely, the Company was able to install new, efficient and effective metering technology across the distribution system beginning in 2013, and customers have benefitted from both the operational upgrade and attendant cost reduction over that time period, and will continue to do so going forward while the next generation metering technology is debated, investigated, decided upon, developed and installed, which will take many years, even if started today. That said, the Company agrees that its meter investments must meet the Commission's standard for cost recovery. The Company recognizes that, although the Company has worked hard to provide evidence that its investments do, in fact, meet this standard, further discussion may be warranted to finalize the collective understanding of what the Company has done to account for the retirements of the legacy metering plant. However, this is a relatively narrow, limited aspect of the overall issue and the Company anticipates that, if focused on prior to the conclusion of this case, a collective understanding could be reached that would allow this issue to be resolved with clarity so that both Staff and PSNH management could focus on future operations.

Q. In the testimony of Mr. Alvarez, does OCA recommend disallowance of the Company's AMR investments?

A. Yes. Mr. Alvarez argues that PSNH's investment in AMR technology was imprudent and that cost recovery should be denied (Alvarez Test. at 5). Mr. Alvarez argues that the Company did not demonstrate that its AMR deployment was necessary; that it should have pursued installation of retrofit "radio modules" as a least cost option; and, if it were to replace its meters, that it should have installed "industry standard technology," meaning advanced metering infrastructure ("AMI") that would enable interval data collection and the implementation of time-varying rates (Alvarez Test. at 5). I respond to each of these claims in the balance of this section of my testimony.[1]

Q. What is your response to OCA's first claim that PSNH has not demonstrated that meter replacement was necessary?

A. This claim is not correct. The record shows that, in the third quarter of 2012, Eversource formed a cross-organizational team to examine the feasibility of migrating from an entirely manual meter reading process to an AMR system. As part of that process, the Company assessed the age and functionality of its existing meters at the time, the vast majority of which were aging, mechanical meters. Based on the Company's annual meter report to the

[1] Mr. Alvarez also claims that the Company's project was "biased and calculated to forestall interval usage data availability" and that it "harmed customers and markets in defiance of New Hampshire law and policy" (Alvarez Test., at 5); however these specious claims are subsumed by his AMI argument.

Commission for the year ending September 30, 2012 (Attachment PMC-Rebuttal-1), tests concluded that approximately 3,500 meters or 0.63 percent of the meter inventory were out of tolerance limits at that time. In addition, PSNH had 56,570 meters that were installed prior to 1962 (i.e., or over 50 years of age), representing approximately 10 percent of installed plant. A total of 188,242 meters (or 33.4% of installed meters) were beyond the 35-year depreciated lifespan. Attachment PMC-Rebuttal-2 provides a listing of installed meters by purchase year.

Moreover, Eversource's analysis in 2012 recognized that mechanical meters by their nature slow down over time, impeding accuracy. In contrast, solid state meters, have a shorter expected lifespan (approximately 20 years per the manufacturer) but keep their accuracy longer over time. In addition, solid-state meters eliminate the drifting problems between the meter's register and the AMR read that can occur with mechanical meters, capturing usage (and revenue) that is generally lost. As a result, solid state meters are now the industry standard (see, Attachment PMC-Rebuttal-3 for an EPRI report from May 2010 on the Accuracy of Digital Meters).

Further, PSNH's legacy metering infrastructure included thousands of meters that had only *four* dials/digits of active kWh information available for meter reading and billing versus the standard of *five* dials/digits, which provides expanded measuring capabilities. These 4-dial meters cause customer confusion and required manual multiplier procedures, prone to user input and interpretation error. With the implementation of the AMR related 5-dial standard, measuring was implemented that eliminated customer confusion and billing errors.

Lastly, beyond the physical condition of the mechanical meter system, the Company's analysis also showed that meter replacement was necessary to obtain substantial cost savings and operational efficiencies.

Q. What is your response to OCA's second claim that, while the meters PSNH installed eliminated manual meter reading, the technology deployed was not the least cost means to do so?

A. This assertion is incorrect and largely based on Mr. Alvarez's speculation. At the time of the team's review in 2012, Eversource's electric and gas subsidiaries in Connecticut and Massachusetts obtained their monthly meter reading data through AMR meters using "drive-by" technology, in which vehicles with radio receivers and laptop computers drive near each meter and the radio signal from the meter transmits the reading to the vehicle, which is later uploaded to the billing systems. The legacy Northeast Utilities companies (The Connecticut Light and Power Company ("CL&P"), Yankee Gas Service Company and Western Massachusetts Electric Company ("WMECO")) used MVRS and Fieldnet software to obtain and process the readings up to the C2 billing system. The NSTAR companies (NSTAR Electric and Gas) used software from Itron FCS to process the reads in a similar manner. At the time that the AMR decision was made, the Eversource team reviewed three primary solutions to the automation of PSNH's meter reading, which included: (1) an AMR system; (2) an AMR/AMI "bridge" option; and (3) a full AMI system. The team determined that an AMR system would provide the most benefits at the least cost by installing a system utilizing AMR meters and drive-by vehicles to obtain the monthly meter readings. This solution leveraged past Company integration efforts, which successfully assimilated the AMR meter data into the Company's legacy C2 billing system and Meter Data Management ("MDM") system.

Q. What did the Company conclude regarding the other options?

A. As the review progressed into the first quarter of 2013, the Company concluded that it would not select the "bridge" option (e.g., remote reading capability and the ability to convert from one-way to two-way communications) because the bridge meter was more expensive (approximately 52% higher at the time than an AMR meter); costs would have to be incurred to utilize them to obtain interval data; and a significant additional cost would be needed to develop a communications network to support full AMI deployment. Similarly, the third option, full AMI deployment, was also ruled out due to the higher cost of the AMI meters, but also due to the costs of design, development and deployment of a sophisticated communications network, as well as associated required upgrades to the billing system, MDM and other system interfaces. I discuss AMI in more detail below.

Q. Did you examine Mr. Alvarez's claim that other technologies existed at the time that were lower cost?

A. Yes, I have examined this claim in great detail. Mr. Alvarez states that, if PSNH's primary goal was to eliminate meter reading operations, "the least cost way to do so in 2013 would have been to add *radio modules* to the existing meters" (Alvarez Test. at 9) (emphasis added). He speculates that radio modules would have had the same functionality as the

Company's AMR (although he concedes that radio modules "have fallen out of favor today") (Alvarez Test. at 9). He also speculates that in 2013 there were likely "millions of mechanical meters retrofitted with AMR in service in the US" and that "[r]etrofit options were offered by major manufacturers like Sensus and Itron," at a small cost per module (Alvarez Test. at 9). These assertions are incorrect.

Q. Why are Mr. Alvarez's assertions incorrect?

A. The radio modules described by Mr. Alvarez *were not available in 2013* and had been discontinued for sale by the manufacturer in 2005. In addition, even if available, radio modules would have been more costly than the AMR installation and operationally inferior.

Q. Please explain.

A. The "radio module" described by Mr. Alvarez is an encoder receiver transmitter ("ERT"), which was a "packet radio" protocol developed by Itron for automatic meter reading. The technology was used to transmit data from utility meters over a short range so a utility vehicle is able to collect meter data without a worker physically inspecting each meter. Itron invented and patented the ERT, and therefore Itron would have had to license any other provider making or selling such units. In August 2004, Itron granted a license to Hunt Technologies, Inc. (now a Landis+Gyr company) to manufacture and sell ERTs, but it was only to install ERTs in original manufacturing of solid-state meters. Itron announced "End of Sales" of its ERTs in October 2005. Last orders were accepted in December 2005 and had to ship by March 2006. As a result, the radio module product espoused by Mr. Alvarez had not been available for approximately seven years at the time of PSNH's AMR deployment in 2013. Itron has informed the Company that it is not aware of any other entity manufacturing or selling retrofit ERTs after 2010. Eversource stopped buying mechanical ERT meters around 2002.

Q. What about Mr. Alvarez's claim that Sensus also provided a retrofit option?

A. Sensus never sold ERTs. Attachment PMC-Rebuttal-4 provides an email from a company representative to that effect.

Q. Beyond the fact that ERTs were unavailable in 2013, what is your basis for concluding that the radio modules would have been a more costly option?

A. The lack of availability of the product alone discounts the radio module as a viable alternative. However, even if the units were available, the cost would have been substantially higher than the Company's AMR project. The last Itron ERT models available in 2005 that may have been suitable for retrofit in most of the PSNH meter population were the ERT II 45ER-1 and ERT II 45ES-1. These units sold for $48 each according to the 2004 Itron price book. To retrofit the ERT into a typical single-phase mechanical meter, Itron would have charged $14 per meter for the retrofit, calibration and testing, and another $1.70 for bar coding, meter handling and packaging, for a total of $15.70 per retrofitted meter. These prices are also extracted from the Itron price book. This means that for the Company's approximately 552,000 meters, the total cost of ERTs and retrofit would have been $63.70 per meter, which equates to $35,162,400. This is $8,361,400 more costly (25%) than new AMR meters, which were purchased for $32.25 per meter.

In addition, PSNH would have had to purchase a minimum of 35,000 "seed stock" meters for about $1.4 million. These meters would have been purchased at a minimum cost of $40.00 per meter to support "single-trip" install work while the old meters were sent to Itron and retrofitted, and then returned to PSNH to be staged for deployment. Without the seed stock to cover rotation time, each meter in the field would have had to be visited twice, once to remove the meter to be retrofitted and install a temporary meter, and again to remove the temporary meter and install a permanent retrofitted meter. This also would have resulted in two service interruptions for the customer.

Because each existing meter would also have been sent back to Itron for the retrofit work, there would also have been an increase in the installation costs, which include meter shipping and transportation. This would have included the packaging of each removed meter; transportation to the Itron facility in South Carolina; handling; packaging; and, return shipping to New Hampshire. This is estimated to have cost an additional $3.7 million.

Further, Meter Acceptance Testing costs would have increased by about $522,000 or 20 percent. The Company tests 10 percent of shipments from the vendor, which includes receiving the pallets, breaking them down, selecting meters from each pallet for testing, performing the testing, comparing results within acceptable values, repackaging the tested meters, and shipping them to the facility from which they will be deployed. AMR meters equated to about $40.50 per meter while ERT retrofitted mechanical meters would equate to about $50.00 per meter. The Company likely would have tested more than 10 percent in the ERT scenario because there would have been a greater potential for errors and issues with retrofitted mechanical meters. However, even without testing greater numbers the testing time would be increased on mechanical meters and in particular where issues are encountered as it takes considerable time to adjust these meters back into acceptable tolerances.

Q. What is the bottom line regarding the claim that radio modules would have been a lower cost alternative?

A. There are no reductions in any of the categories of project costs as compared to AMR implementation; instead, only increases. The Company estimates that this option would have increased costs by about $13 million, or a 25 percent increase in the project costs. Attachment PMC-Rebuttal-5 provides a high-level illustrative cost comparison for purposes of this proceeding of the Company's AMR project to a retrofit of radio modules.[2]

Q. Beyond product availability and increased costs, are there operational reasons why retrofitting old meters with radio modules would not have been a viable option?

A. Yes, there were many additional reasons why this would not have been a viable option, including:

1. Age of the Meters: Many of PSNH's mechanical meters were near, at, or beyond their useful service life, and some meters were too old to be retrofitted with radio modules due to their construction/design. Some meters were likely

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[2] Mr. Alvarez speculates that "the cost of retrofitting a drive-by system in 565,000 existing meters would probably have been less than $20 per meter" (Alvarez Test. at 10-11). However, he provides no cost data or documentary evidence to support his claim.

not compatible with any manufactured retrofit devices.

2. Performance: The measurement accuracy of new solid-state meters is significantly better than the older electromechanical meters. There have been cases where the mechanical dial readings did not match the ERT transmitted usage due to a variety of reasons, not all of which represent a malfunctioning meter or ERT, which led to billing issues/concerns.

3. Support: Original ERT suppliers had phased-out production and support for retrofit products and therefore PSNH would have been purchasing and deploying products that were obsolete even before they were deployed.

4. New Features – Application Flexibility: The solid-state meters offered more application flexibility and features than electromechanical meters, such as bidirectional (net) metering, time-of-use, demand with remote reset capability, event logs, programmability, self-monitoring/error/tamper codes, and similar features.

Q. What is your response to OCA's third claim that if PSNH were to replace its meters, it should have used "industry standard technology (i.e., advanced metering infrastructure)" offering interval usage data?

A. AMI was not "industry standard technology" at the time of the Company's AMR deployment. In fact, in 2012-2013, a number of other companies were installing AMR systems. For example, AEP Ohio had commenced an initiative to expand installation of AMR in its service territory to approximately 204,000 customers. In a news release, AEP cited increased meter reading percentages, reduced estimated bills, and a safer work environment for its employees as the reason for the expansion of AMR (Attachment PMC-Rebuttal-6). Similarly, EEI reported that MidAmerican Energy installed 1.5 million AMR meters in 2013. More generally, a June 2012 article in Green Tech Media entitled "The Smart Meter Landscape: 2012 and Beyond" concluded that AMI or smart meter deployment was on a *downward* trend, due to a lack of stimulus funding to help cover the costs of AMI deployment. The article also noted that less than half of all meters in the U.S. were predicted to be AMI meters by the end of the 2012 (Attachment PMC-Rebuttal-7).

Q. Do companies continue to install AMR meters today?

A. Yes. According to Itron, a number of utilities continue to maintain their AMR meter reading systems that are providing valuable billing and metering information, including National Grid, Consolidated Edison, Detroit Edison, Duke Energy, Consumers Power, South Carolina Gas, NiSource, Central Hudson and CNP.

Q. Would AMI have been more expensive than the Company's AMR installation?

A. Yes, AMI was a far more expensive option. Mr. Alvarez cites a Company business case presentation from 2012 for a single ($25 million) cost component of an AMI deployment (Alvarez Test. at 25-26, citing Attachment TS 1-011A, at 4), but he does not consider the total cost of AMI. In fact, the Company business case in 2012 analyzed AMI solely as a metering alternative (without the two-way communication functionality required to offer time-varying rates), identifying a net capital requirement in excess of $110 million for AMI with an average installed cost per meter of $202.29, compared to AMR cost of approximately $39 million and cost per meter of $70.55 (Attachment TS 1-011A), at 4). More importantly, the functionality that this investment would have produced, *did not include two-way communication capability,* which is necessary to collect interval data and enable real-time use of time-varying rates. This fact alone was definitive proof that AMI would not have been a cost-effective option.

Since 2012, the Company has since conducted additional analysis to refine the AMI cost projection from the high-level estimate used in the 2012 business case, which shows that the cost of fully enabled AMI would likely exceed $200 million in New Hampshire. Attachment PMC-Rebuttal-5 includes a breakdown of the cost of an AMI installation, including IT system costs that were not developed at the time of the business case and account for $78 million in added costs necessary to achieve the two-way communication and time-varying rates capability.

Q. Beyond cost, what are some of the impediments that have hindered AMI deployments in the United States?

A. At the time of the Company's business case review, most utilities in the United States deploying AMI did so either to satisfy regulatory mandates (such as in California and Texas) or because the companies were receiving federal stimulus money (Smart Grid Investment Grants), which dramatically reduced the cost burden to customers. This was the case for companies such as Central Maine Power and the New Hampshire Electric Cooperative, to cite two local examples. Conversely, there were no existing or potential regulatory mandates in any of the Eversource service territories regarding AMI at that time.

Additionally, Eversource was concerned about customer opposition to AMI meters, which was spreading in some areas of the country (such as Maine and California), as well as a lack of interest in customer participation in off-peak pricing programs.

A recent study by the American Council for an Energy-Efficient Economy (ACEEE")[3] cites several factors that impede AMI deployment, including challenges in delivering promised customer benefits. "Generally, the reason cited is that AMI remains too costly relative to the benefits, or that utilities have not verified to the regulator's satisfaction the likelihood of those benefits. In a few cases customer suspicions of alleged negative health impacts of AMI, such as radiation, have hindered rollouts" (ACEEE Report at 6). The report further states that "AMI produces a much higher volume of customer data than traditional analog meters. Having additional data creates opportunities for energy savings but also raises data privacy and cybersecurity concerns" (ACEEE Report at 32). "'AMI deployments raise new questions about the security of customer data, the types of entities that can access it, and how the data will be protected from cybersecurity breaches and other data privacies intrusion (DOE 2016)'" (ACEEE Report at 32).

Q. Is Mr. Alvarez's position on AMI in this proceeding inconsistent with positions he has taken in other jurisdictions?

A. Yes. Mr. Alvarez concedes he has been consistently critical of utility AMI deployments in other cases, stating that his testimony "generally claims that the benefits of an AMI

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[3] The ACEE Report is available at: https://www.aceee.org/research-report/u2001

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deployment would be unlikely to deliver (in the case of deployment plans) or did not deliver (in the case of requested cost recovery) benefits to customers in excess of costs to customers" (Alvarez Test. at 27). Mr. Alvarez's claim in this case – i.e., that AMI was a feasible and cost-effective option for the Company in 2013 -- is inconsistent with his prior positions.

Q. Was the Company's decision to install AMR meters instead of AMI "biased and calculated to forestall interval usage data availability" as Mr. Alvarez claims?

A. No. In addition to all of the reasons why AMI was neither industry standard nor a cost-effective option, there was no "push" for TVR at that time, and in fact TVR would have a negative impact on the most vulnerable customers, who are unable to shift load. It takes time for new rates to incent behavior and it was unclear whether the ultimate solution could be more dynamic than TVR. Today, Eversource can accomplish peak load reduction without TVR. Moreover, seven years after the Company's AMR deployment, the State of New Hampshire has not moved forward on grid modernization policies that would require AMI, and the timeline of potential developments in areas such as peak demand reduction and TVR is uncertain.

Q. Was the Company's decision to install AMR meters harmful to "customers and markets in defiance of New Hampshire law and policy" as Mr. Alvarez claims?

A. No, this claim fails for the same reasons as Mr. Alvarez's other assertions. He states his belief that "PSNH's decision to install meters without industry-standard interval usage data capabilities stifles, rather than empowers, competitive electricity markets and market innovation" (Alvarez Test. at 31), but he provides no evidence that AMI has had these effects. In fact, all of the Eversource distribution companies in New Hampshire, Connecticut and Massachusetts have seen similar levels of customers choice, with a majority of large industrial customers (and hence the large majority of the load) in these states taking service from competitive suppliers. The Company's AMR system has no impact or bearing on the competitive supply market in this regard. The Company's decision in 2013 to deploy AMR has yielded substantial cost savings and benefits to customers.

III. FEE FREE, ARREARAGE FORGIVENESS AND CUSTOMER ISSUES

Q. Please describe the Staff's recommendations related to the fee free proposal.

A. Staff supports adoption of the fee free program but with two modifications. Specifically, Staff recommends that the program should allow all customers paying with a credit or debit card, whether recurring or non-recurring, to do so without a transaction charge, stating that there is no need to distinguish recurring from non-recurring and no rationale for penalizing customers who make automatic payments (Noonan Test. at 4). Staff also recommends that the Company should file an annual report by March 1 to report on various aspects of the program, as filed by the Company's Connecticut affiliate (Noonan Test. at 5).

Q. What is the Company's response to these recommendations?

A. The Company appreciates Staff's support of the fee free program. In this proposal, PSNH is aiming to eliminate the current customer pain point associated with fee-based credit and debit card payments, while ensuring that the total cost of offering fee free payments is a net positive value for customers. However, while Eversource is interested in offering fee free recurring credit card payments at some time in the future, it is not currently offering or proposing fee free recurring payments in any of its service territories at this time. The Company's seeks to gain additional experience over time with customer adoption rates for the one-time payment approach. The Company is closely monitoring emerging options from the credit card companies to offer a flat fee for recurring payments in conjunction with fee free non-recurring payments. However, such options are not broadly available and are not yet offered by credit card companies today. For this reason, the Company does not support Staff's recommendation to provide fee free for recurring payments.

Q. What is the challenge in providing fee free for recurring payments?

A. The Company and its industry peer utilities do not currently have a basis to estimate costs for fee free recurring payment credit card utilization. In contrast, the Company has a reasonable basis for projecting non-recurring fee free credit card payment utilization from peer utilities and from Eversource's first nine months of offering fee free in Connecticut. For example, in Connecticut, credit card payment utilization as a percent of total payments increased from 3.97 percent to 5.4 percent during the first nine months of the program. For these reasons, the Company proposes initially offering fee free credit and debit card payments only on a non-recurring basis, to help ensure incremental costs are consistent with the value to all customers.

Q. Does the Company support Staff's recommendation to provide an annual report on the fee free program?

A. Yes, the Company would agree to file a report annually like the one provided by Eversource in Connecticut.

Q. Does Staff also make a recommendation to modify the cost recovery for the fee free proposal?

A. Yes. Staff recommends that any over-collection would not be credited to residential customers and any over-collection in the reserve fund would incur interest (credit) on monthly balances. Staff also recommends that any under-collection would incur monthly carrying costs (Chagnon Test. at 30). Staff recommends recovery of $707,000 annually beginning July 1, 2020 and ending on the effective the date of its next permanent rate case and approval from the Commission for permanent rates in that preceding (Chagnon Test. at 30). Any over or under-collection in the reserve account would be deferred for refund or recovery in rates at the time permanent rates are approved and effective in the Company's next rate case (Chagnon Test. at 30).

Q. Does the Company agree with Staff's modifications to cost recovery for the fee free proposal?

A. The Company is generally supportive of the reserve fund accounting as proposed by Staff with interest accruing for both under and over-collections.

Q. On the New Start arrearage forgiveness proposal, please describe the Staff's recommendations.

A. Staff supports adoption of this program but recommends the addition of certain eligibility criteria, program parameters and reporting requirements (Noonan Test. at 3). Specifically, Staff recommends that the program should be made available to any account coded financial hardship; that customers with past due balances greater than $300 and greater than 60 days should be eligible for enrollment; that if a customer misses a payment, the payment must be made up to continue enrollment; that new enrollments can occur 12 months after being dropped from the program; that new enrollments can occur 12 months after successful completion of the program for customers with no remaining past due balance upon completion; that customers who successfully complete the program, and who still have a remaining past due balance, may re-enroll immediately and will not be subject to the 12-month waiting period; that customers will be automatically enrolled in a budget plan following successful completion of the program; and that the annual cap on the forgiveness amount should be $12,000 (Noonan at 6-7). Overall, Staff recommends establishing a stakeholder group to develop a comprehensive program design for the New Start program (Noonan Test. at 8).

Q. What is the Company's response to these recommendations?

A. The Company appreciates Staff's support of the New Start program and recognizes there are a number of program design issues to ensure effective implementation. The Company supports discussion of these issues in a stakeholder process. PSNH proposes to work through the Electric Assistance Program, or "EAP" for New Start, which brings together the Commission, OCA, the action agencies. The EAP a program to address energy cost burdens for low income customers and makes sense for consideration of New Start.

Q. Does Staff recommend an annual reporting requirement related to New Start?

A. Yes. Staff recommends that the Company should submit a plan and format for annual reporting on the New Start program for review and approval by the Staff within 90 days of the Commission's final order in this proceeding (Noonan Test. at 8). Staff states that the plan should include the collection and reporting of data prior to the start of the program in order to provide a baseline (Noonan Test. at 8). The Company supports this recommendation.

Q. Does Staff propose to modify the cost recovery for implementation of the New Start proposal?

A. Yes. The Staff alleges that Company proposed to recover its capital costs to implement the program, estimated at $1.7 million, through the Distribution Rate Adjustment Mechanism ("DRAM")[4], which Staff does not support. Staff recommends that PSNH should recover the $1.7M of start-up costs over five years beginning July 1, 2020, which is approximately $340,000 annualized (Chagnon Test. at 16). If the Company files a rate case for permanent rates or temporary rates in 2025, any over or under-collection of the actual implementation costs would be fully reconciled for rates effective July 1, 2025; and if the Company does not file a rate case for permanent rates or temporary rates in 2025 or before, any over or under-collection for the actual costs would be fully reconciled for rates effective July 1, 2025 (Chagnon Test. at 16). Lastly, if the Company files a rate case for permanent rates or temporary rates prior to 2025, Staff recommends that the actual implementation costs would be addressed in that rate case (Chagnon Test. at 17).

Q. Does the Company agree with Staff's proposal?

A. Given that the Staff is providing a fully reconciling mechanism for the recovery of these startup costs, the Company is supportive of the recommendation under the presumption

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[4] The Company's proposal was to recover capital costs of $1.7M through step adjustments. Any arrearage forgiveness costs would be recovered through the DRAM mechanism.

that carrying charges would accrue for the under or over collection of costs.

Q. Does Staff propose additional modifications to the cost recovery for the New Start proposal?

A. Yes. For past-due balances forgiven through the program, the Staff recalculates the recovery amount to be $4,176,985 and proposes to recover it over 4.5 years beginning July 1, 2020, for a net annual recovery of $842,000 (Chagnon Test. at 17). Staff recommends that the Company create a reserve account for funds collected through rates for the New Start program and to reflect all amounts charged to the New Start program created by forgiven past due balance amounts (Chagnon Test at 19). Staff states that any over-collection in the reserve fund would incur interest (credit) on monthly balances, but that any under-collection would not incur monthly carrying charges.

Q. Does the Company agree with Staff's proposal?

A. Carrying charges on over or under-collections should be symmetrical, as suggested for the fee free program. Staff's recommendation for New Start is inconsistent with its proposed treatment of costs associated with the fee free program where symmetrical treatment is supported. There is no basis for denying carrying charges on under-collections and it does not make sense to allow a buildup of amounts for future recovery of forgiven arrears. The Company's initial proposal was designed with recovery through the DRAM so that costs are recovered from contemporaneously with cost incurrence maintaining alignment between the customers obtaining the benefit and the customers providing the benefit. The Company's proposal to put this through the DRAM accomplishes this alignment, mitigates carrying costs and allows for experience to be gained with the program before fixing an unrepresentative or speculative amount in base rates now.

Q. Lastly, does the Company have a response to the customer issues raised in the testimony of intervenor The Way Home?

A. Yes. The Company appreciates The Way Home's participation in this process and its support of the fee free program (Colton Test. at 8). The Company also appreciates The Way Home's support of the New Start program, although many of its extensive modification proposals in areas such as program structure, implementation and cost recovery are unnecessary and unwarranted, or would run counter to successful and cost-effective program implementation (Colton Test. at 5-7). Recognizing that Staff has suggested establishing a stakeholder group to develop a comprehensive program design for the New Start program, the stakeholder group would be a more appropriate forum in which to address the concepts raised in The Way Home's testimony.

Q. Does The Way Home raise additional customer issues?

A. Yes. The Way Home recommends that the Company should modify certain practices related to service disconnection notices, non-English language communications, and deferred payment arrangements (Colton Test. at 7-8). The testimony provides no evidence on non-compliance by PSNH and none of these changes are warranted at this time. In fact, the Company complies with all rules and regulations of the Commission related to its customer service practices.

Q. Does this conclude your testimony?

A. Yes.

Form E3A

The State of New Hampshire
Public Utilities Commission, Concord, NH
Annual Report

Selective Meter Tests (Self Contained Single-Phase Meters)

of the Public Service Company of NH, Year Ending September 30, 2012

	Year	2009		2010		2011		2012	
1	Meters on Lines	562,158		563,470		563,445		563,119	
1a	Sample Meters on Lines	536,213		537,427		536,901		536,951	
2	Sample	year	cum	year	cum	year	cum	year	cum
3	Percent Out of Limits	0.78%	0.58%	0.71%	0.63%	0.39%	0.62%	0.56%	0.61%
4	Additional Meters	2,190		2,570		3,097		3,081	
5	Non-Register	8	27	8	27	4	27	10	30
6	Less Than 94%	7	29	6	29	3	25	5	21
7	94% to 98%	21	44	18	53	8	56	7	54
8	98% to 101%	5,289	21,075	5,303	21,151	5,344	21,224	5,321	21,257
8a	101% to 102% electromechanical	35	115	39	137	30	134	36	140
8b	101% to 102% electronic	0	0	0	0	0	0	0	0
9	102% to 106%	6	19	5	21	5	22	8	24
10	Over 106%	0	4	1	4	1	4	0	2
11	Total Sample For Year	5,366		5,380		5,395		5,387	
12	Maintenance	0		0		0		0	
13	Miscellaneous	1,219		1,585		1,145		1,734	
14	Additional Meters	3,295		4,584		4,210		4,448	
	Grand Total	9,880		11,549		10,750		11,569	

(line 14 should be greater than or equal to line 4)

Signed by: ______________________ **Title:** ______________________

Date: ______________________

Sum of COUNT(*)	Unit Of Property																
Purch. Year	KY00000	KY10670	KY10671	KY10672	KY10673	KY10675	KY10677	KY16921	KY16967	KY16968	KY16969	KY19000	KY19547	KY19583	KY19625	KY19867	Grand Total
1933		1															1
1934		46															46
1935		6	2	5	12	2			2								29
1936		19															19
1937		18															18
1938		37				2											39
1939		108							1								109
1940		112									1						113
1941		88								1							89
1942		9															9
1943		5															5
1944		1															1
1945		57	2		1				1								61
1946		874				1			4								879
1947		2652				11			7								2670
1948		2556				10			6								2572
1949		1519				9			1								1529
1950		3631				11			6	1							3649
1951		1479			1	28				17	5						1530
1952		1285			3	15			1	3	4						1311
1953		1273				26			4	26	3						1332
1954		5583		1	5	166			25	19	3						5802
1955		3590			1	207			22	18	3						3841
1956		3535			9	208			154	70	6						3982
1957		2794		2	2	59			12	31	9						2909
1958		2552			1	76			10	25	7						2671
1959		4523			1	8			14	20	1						4567
1960		5680			1	9			21	141	10						5862
1961		5517		1	1	6			4	65	5						5599
1962		5295			2	3			18	4	4						5326
1963		5198				6			37	36							5277
1964		5036				3			13	12	2						5066
1965		6292							65	101	2						6460
1966		4369		1		8			1	42	4						4425
1967		5275		2	3	1			1	30	6						5318
1968		6687		2	2	2			9	51	3						6756
1969		7607			1				13	77	4						7702
1970		9859		2		2			29	126	8						10026
1971		11669		1		4			84	263	12						12033
1972		11771		5		2			48	175	7						12008
1973		14303		7	5	1			54	473	18						14861
1974		8921		12	2	3			47	589	20						9594
1975		10944		6					230	198	12						11390
1976		9730		17		4			77	66	10						9904
1977		10569		24	2				74	176	7						10852
1978		10133		45	1				74	350	29						10632
1979		12339		20	2				69	339	35						12804
1980		11085		20	1	3			74	446	13						11642
1981		9305		9	4	26			107	542	36						10029
1982		9481		20	1	92			107	1658	28						11387
1983		11133		27		34			168	1494	105						12961
1984		10622		30		62			30	1502	160						12406
1985		11700		32		5			190	1757	183						13867
1986		18373		61		35			341	1217	138						20165
1987		11590		92	1	33			432	786	125						13059
1988		10798		119		14			594	937	107						12569
1989		7108		216	2				642	361	57						8386
1990		4646		54					431	414	50						5595
1991		2951		190					347	87	50						3625
1992		6797		162	1				515	92		1		2			7570
1993		4666		94	1	2			642	179							5584
1994		5562	4	712		1			584	181	108						7152
1995		5042	1	536					525	355	94						6553
1996		4513	4	575					540	186	89		13	19			5939
1997		7874	11	657	1				369	458	64			7			9441
1998		7771	4	503					489	260		9		12			9048
1999		6671		375	1			1	608	278	84	1	232	42			8293
2000		9218		543				4	590	355	129	2	920	709			12470
2001		6806	19	948					905	455	134		949	30			10246
2002		10207	20	944				1	566	463	42	2	1504	240			13989
2003		7409	9	1233					1157	663	87	3	2836	73	46	21	13537
2004		12194	7	1475					964	665	170		1749	193			17417
2005		8482	11	1046					413	661	65		557	48			11283
2006		10237	10	1608		2		50	545	952	68		95	167			13734
2007		9000	11	1399					498	380	65		568	57		3	11981
2008		8204	4	1329	1				294	236	43		482	197		20	10810
2009		8019	1	1353					382	590	44	1	128	116		44	10678
2010	62	7293		1466					1019	304	73	1	2136	182		30	12566
2011	564	4288		910			644		829	459	53		3860	62		53	11722
2012	173	3313		482					158	309	33		2793	56			7317
Grand Total	**799**	**477905**	**120**	**19373**	**72**	**1202**	**644**	**56**	**17293**	**23227**	**2737**	**20**	**18822**	**2212**	**46**	**171**	**564699**

UNITOFPROPNO	DESCRIPTION
EV17613	RADIO CONTROL UNIT
KY00000	Virtual Meter
KY10549	TIME SWITCH
KY10670	SINGLE PHASE WITHOUT DEMAND
KY10671	POLYPHASE 3 - WIRE
KY10672	POLYPHASE 4 - WIRE
KY10673	SPECIAL SWITCHBOARD MOUNTED
KY10674	SPECIAL KVA INDICATING AND RECORDING DEMAND
KY10675	SINGLE PHASE COMBINATION WATTHOUR AND TIME SWITCH
KY10676	POLYPHASE COMBINATION WATTHOUR AND TIME SWITCH
KY10677	THERMAL DEMAND
KY10678	POLYPHASE 5 - WIRE
KY12576	QUADRAPHASER (PHASING TRANSFORMER)
KY13128	SPECIAL RECORDING DEMAND
KY16921	SINGLE PHASE TIME OF DAY
KY16967	SINGLE PHASE WITH DEMAND
KY16968	NETWORK WITHOUT DEMAND
KY16969	NETWORK WITH DEMAND
KY17507	TOTALIZER
KY17609	METER TIME OF USE RECORDING DEMAND
KY19000	POLYPHASE TIME OF DAY
KY19547	SINGLE PHASE AMR
KY19583	MULTIFUNCTION WATTHOUR METER
KY19625	NETWORK AMR
KY19867	SINGLE PHASE DEMAND AMR
KY19868	THREE PHASE AMR VAN DEMAND 27033117
KY19869	THREE PHASE AMR VAN DEMAND 27034137 27034117
KY19870	AMR NETWORK DEMAND
KY19963	ami 2 way communication
KY21150	CURRENT TRANSFORMER
KY21151	POTENTIAL TRANSFORMER
KY23145	single phase meter with remote disconnect capabilities
KY23148	Single Phase Meter with Disconnect capability

PYEAR	UNITOFPROPNO	COUNT(*)
2012	KY00000	173
2012	KY10670	3313
2012	KY10672	482
2012	KY16967	158
2012	KY16968	309
2012	KY16969	33
2012	KY19547	2793
2012	KY19583	56
2011	KY00000	564
2011	KY10670	4288
2011	KY10672	910
2011	KY10677	644
2011	KY16967	829
2011	KY16968	459
2011	KY16969	53
2011	KY19547	3860
2011	KY19583	62
2011	KY19867	53
2010	KY00000	62
2010	KY10670	7293
2010	KY10672	1466
2010	KY16967	1019
2010	KY16968	304
2010	KY16969	73
2010	KY19000	1
2010	KY19547	2136
2010	KY19583	182
2010	KY19867	30
2009	KY10670	8019
2009	KY10671	1
2009	KY10672	1353
2009	KY16967	382
2009	KY16968	590
2009	KY16969	44
2009	KY19000	1
2009	KY19547	128
2009	KY19583	116
2009	KY19867	44
2008	KY10670	8204
2008	KY10671	4
2008	KY10672	1329
2008	KY10673	1
2008	KY16967	294
2008	KY16968	236
2008	KY16969	43
2008	KY19547	482

2008	KY19583	197
2008	KY19867	20
2007	KY10670	9000
2007	KY10671	11
2007	KY10672	1399
2007	KY16967	498
2007	KY16968	380
2007	KY16969	65
2007	KY19547	568
2007	KY19583	57
2007	KY19867	3
2006	KY10670	10237
2006	KY10671	10
2006	KY10672	1608
2006	KY10675	2
2006	KY16921	50
2006	KY16967	545
2006	KY16968	952
2006	KY16969	68
2006	KY19547	95
2006	KY19583	167
2005	KY10670	8482
2005	KY10671	11
2005	KY10672	1046
2005	KY16967	413
2005	KY16968	661
2005	KY16969	65
2005	KY19547	557
2005	KY19583	48
2004	KY10670	12194
2004	KY10671	7
2004	KY10672	1475
2004	KY16967	964
2004	KY16968	665
2004	KY16969	170
2004	KY19547	1749
2004	KY19583	193
2003	KY10670	7409
2003	KY10671	9
2003	KY10672	1233
2003	KY16967	1157
2003	KY16968	663
2003	KY16969	87
2003	KY19000	3
2003	KY19547	2836
2003	KY19583	73
2003	KY19625	46

2003	KY19867	21
2002	KY10670	10207
2002	KY10671	20
2002	KY10672	944
2002	KY16921	1
2002	KY16967	566
2002	KY16968	463
2002	KY16969	42
2002	KY19000	2
2002	KY19547	1504
2002	KY19583	240
2001	KY10670	6806
2001	KY10671	19
2001	KY10672	948
2001	KY16967	905
2001	KY16968	455
2001	KY16969	134
2001	KY19547	949
2001	KY19583	30
2000	KY10670	9218
2000	KY10672	543
2000	KY16921	4
2000	KY16967	590
2000	KY16968	355
2000	KY16969	129
2000	KY19000	2
2000	KY19547	920
2000	KY19583	709
1999	KY10670	6671
1999	KY10672	375
1999	KY10673	1
1999	KY16921	1
1999	KY16967	608
1999	KY16968	278
1999	KY16969	84
1999	KY19000	1
1999	KY19547	232
1999	KY19583	42
1998	KY10670	7771
1998	KY10671	4
1998	KY10672	503
1998	KY16967	489
1998	KY16968	260
1998	KY19000	9
1998	KY19583	12
1997	KY10670	7874
1997	KY10671	11

1997	KY10672	657
1997	KY10673	1
1997	KY16967	369
1997	KY16968	458
1997	KY16969	64
1997	KY19583	7
1996	KY10670	4513
1996	KY10671	4
1996	KY10672	575
1996	KY16967	540
1996	KY16968	186
1996	KY16969	89
1996	KY19547	13
1996	KY19583	19
1995	KY10670	5042
1995	KY10671	1
1995	KY10672	536
1995	KY16967	525
1995	KY16968	355
1995	KY16969	94
1994	KY10670	5562
1994	KY10671	4
1994	KY10672	712
1994	KY10675	1
1994	KY16967	584
1994	KY16968	181
1994	KY16969	108
1993	KY10670	4666
1993	KY10672	94
1993	KY10673	1
1993	KY10675	2
1993	KY16967	642
1993	KY16968	179
1992	KY10670	6797
1992	KY10672	162
1992	KY10673	1
1992	KY16967	515
1992	KY16968	92
1992	KY19000	1
1992	KY19583	2
1991	KY10670	2951
1991	KY10672	190
1991	KY16967	347
1991	KY16968	87
1991	KY16969	50
1990	KY10670	4646
1990	KY10672	54

1990	KY16967	431
1990	KY16968	414
1990	KY16969	50
1989	KY10670	7108
1989	KY10672	216
1989	KY10673	2
1989	KY16967	642
1989	KY16968	361
1989	KY16969	57
1988	KY10670	10798
1988	KY10672	119
1988	KY10675	14
1988	KY16967	594
1988	KY16968	937
1988	KY16969	107
1987	KY10670	11590
1987	KY10672	92
1987	KY10673	1
1987	KY10675	33
1987	KY16967	432
1987	KY16968	786
1987	KY16969	125
1986	KY10670	18373
1986	KY10672	61
1986	KY10675	35
1986	KY16967	341
1986	KY16968	1217
1986	KY16969	138
1985	KY10670	11700
1985	KY10672	32
1985	KY10675	5
1985	KY16967	190
1985	KY16968	1757
1985	KY16969	183
1984	KY10670	10622
1984	KY10672	30
1984	KY10675	62
1984	KY16967	30
1984	KY16968	1502
1984	KY16969	160
1983	KY10670	11133
1983	KY10672	27
1983	KY10675	34
1983	KY16967	168
1983	KY16968	1494
1983	KY16969	105
1982	KY10670	9481

1982	KY10672	20
1982	KY10673	1
1982	KY10675	92
1982	KY16967	107
1982	KY16968	1658
1982	KY16969	28
1981	KY10670	9305
1981	KY10672	9
1981	KY10673	4
1981	KY10675	26
1981	KY16967	107
1981	KY16968	542
1981	KY16969	36
1980	KY10670	11085
1980	KY10672	20
1980	KY10673	1
1980	KY10675	3
1980	KY16967	74
1980	KY16968	446
1980	KY16969	13
1979	KY10670	12339
1979	KY10672	20
1979	KY10673	2
1979	KY16967	69
1979	KY16968	339
1979	KY16969	35
1978	KY10670	10133
1978	KY10672	45
1978	KY10673	1
1978	KY16967	74
1978	KY16968	350
1978	KY16969	29
1977	KY10670	10569
1977	KY10672	24
1977	KY10673	2
1977	KY16967	74
1977	KY16968	176
1977	KY16969	7
1976	KY10670	9730
1976	KY10672	17
1976	KY10675	4
1976	KY16967	77
1976	KY16968	66
1976	KY16969	10
1975	KY10670	10944
1975	KY10672	6
1975	KY16967	230

1975	KY16968	198
1975	KY16969	12
1974	KY10670	8921
1974	KY10672	12
1974	KY10673	2
1974	KY10675	3
1974	KY16967	47
1974	KY16968	589
1974	KY16969	20
1973	KY10670	14303
1973	KY10672	7
1973	KY10673	5
1973	KY10675	1
1973	KY16967	54
1973	KY16968	473
1973	KY16969	18
1972	KY10670	11771
1972	KY10672	5
1972	KY10675	2
1972	KY16967	48
1972	KY16968	175
1972	KY16969	7
1971	KY10670	11669
1971	KY10672	1
1971	KY10675	4
1971	KY16967	84
1971	KY16968	263
1971	KY16969	12
1970	KY10670	9859
1970	KY10672	2
1970	KY10675	2
1970	KY16967	29
1970	KY16968	126
1970	KY16969	8
1969	KY10670	7607
1969	KY10673	1
1969	KY16967	13
1969	KY16968	77
1969	KY16969	4
1968	KY10670	6687
1968	KY10672	2
1968	KY10673	2
1968	KY10675	2
1968	KY16967	9
1968	KY16968	51
1968	KY16969	3
1967	KY10670	5275

1967	KY10672	2
1967	KY10673	3
1967	KY10675	1
1967	KY16967	1
1967	KY16968	30
1967	KY16969	6
1966	KY10670	4369
1966	KY10672	1
1966	KY10675	8
1966	KY16967	1
1966	KY16968	42
1966	KY16969	4
1965	KY10670	6292
1965	KY16967	65
1965	KY16968	101
1965	KY16969	2
1964	KY10670	5036
1964	KY10675	3
1964	KY16967	13
1964	KY16968	12
1964	KY16969	2
1963	KY10670	5198
1963	KY10675	6
1963	KY16967	37
1963	KY16968	36
1962	KY10670	5295
1962	KY10673	2
1962	KY10675	3
1962	KY16967	18
1962	KY16968	4
1962	KY16969	4
1961	KY10670	5517
1961	KY10672	1
1961	KY10673	1
1961	KY10675	6
1961	KY16967	4
1961	KY16968	65
1961	KY16969	5
1960	KY10670	5680
1960	KY10673	1
1960	KY10675	9
1960	KY16967	21
1960	KY16968	141
1960	KY16969	10
1959	KY10670	4523
1959	KY10673	1
1959	KY10675	8

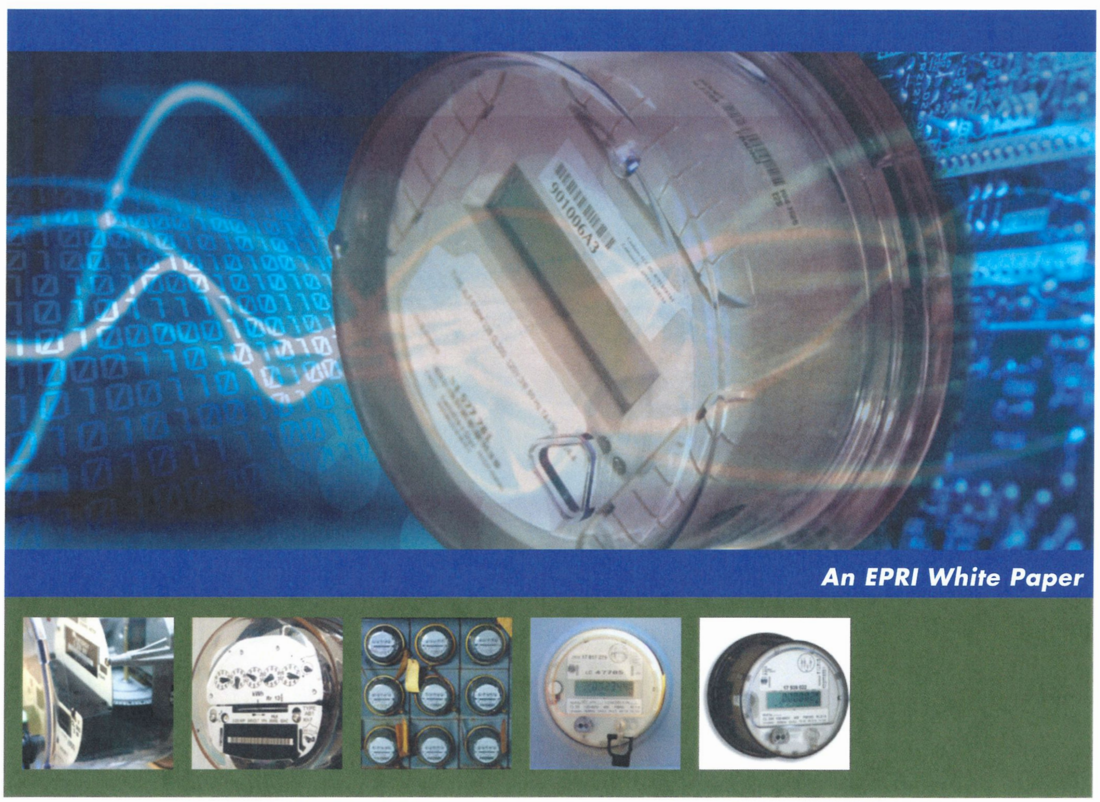
1959	KY16967	14
1959	KY16968	20
1959	KY16969	1
1958	KY10670	2552
1958	KY10673	1
1958	KY10675	76
1958	KY16967	10
1958	KY16968	25
1958	KY16969	7
1957	KY10670	2794
1957	KY10672	2
1957	KY10673	2
1957	KY10675	59
1957	KY16967	12
1957	KY16968	31
1957	KY16969	9
1956	KY10670	3535
1956	KY10673	9
1956	KY10675	208
1956	KY16967	154
1956	KY16968	70
1956	KY16969	6
1955	KY10670	3590
1955	KY10673	1
1955	KY10675	207
1955	KY16967	22
1955	KY16968	18
1955	KY16969	3
1954	KY10670	5583
1954	KY10672	1
1954	KY10673	5
1954	KY10675	166
1954	KY16967	25
1954	KY16968	19
1954	KY16969	3
1953	KY10670	1273
1953	KY10675	26
1953	KY16967	4
1953	KY16968	26
1953	KY16969	3
1952	KY10670	1285
1952	KY10673	3
1952	KY10675	15
1952	KY16967	1
1952	KY16968	3
1952	KY16969	4
1951	KY10670	1479

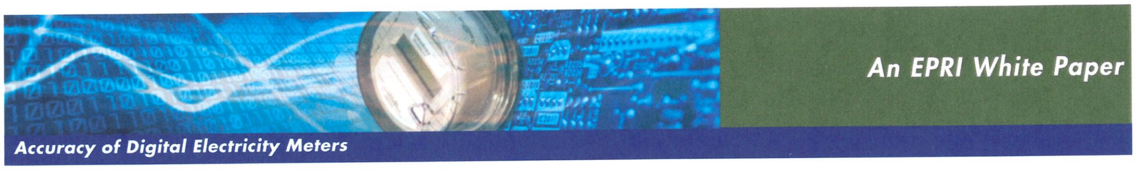
1951	KY10673	1
1951	KY10675	28
1951	KY16968	17
1951	KY16969	5
1950	KY10670	3631
1950	KY10675	11
1950	KY16967	6
1950	KY16968	1
1949	KY10670	1519
1949	KY10675	9
1949	KY16967	1
1948	KY10670	2556
1948	KY10675	10
1948	KY16967	6
1947	KY10670	2652
1947	KY10675	11
1947	KY16967	7
1946	KY10670	874
1946	KY10675	1
1946	KY16967	4
1945	KY10670	57
1945	KY10671	2
1945	KY10673	1
1945	KY16967	1
1944	KY10670	1
1943	KY10670	5
1942	KY10670	9
1941	KY10670	88
1941	KY16968	1
1940	KY10670	112
1940	KY16969	1
1939	KY10670	108
1939	KY16967	1
1938	KY10670	37
1938	KY10675	2
1937	KY10670	18
1936	KY10670	19
1935	KY10670	6
1935	KY10671	2
1935	KY10672	5
1935	KY10673	12
1935	KY10675	2
1935	KY16967	2
1934	KY10670	46
1933	KY10670	1

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Accuracy of Digital Electricity Meters

May 2010





Background

The meter is a critical part of the electric utility infrastructure. It doesn't provide a control function for the power system, but it is one of the most important elements from a monitoring and accounting point of view. Meters keep track of the amount of electricity transferred at a specific location in the power system, most often at the point of service to a customer. Like the cash-register in a store, these customer meters are the place where the transaction occurs, where the consumer takes possession of the commodity, and where the basis for the bill is determined. Unlike a cash-register, however, the meter sits unguarded at the consumer's home and must be trusted, by both the utility and the home owner, to accurately and reliably measure and record the energy transaction.

Electricity is not like other commodities because it is consumed in real-time. There is nothing to compare or measure later, nothing to return, nothing tangible to show what was purchased. This makes the meter all the more critical for both the utility and the homeowner. For this reason, meters and the sockets into which they are installed are designed to standards and codes that discourage tampering and provide means of detecting when it is attempted. Intentional abuses aside, the electricity meter itself must be both accurate and dependable, maintaining its performance in spite of environmental and electrical stresses.

In general, electricity meters have been able to achieve these goals and in so doing to earn the trust of utilities and homeowners alike. The average person may have experienced a broken-down car, a worn-out appliance, or a piece of electrical equipment that died in a lightening storm, but most don't likely recall their electricity meter ever failing. Such is the reliable legacy of the electromechanical meter.

Historical Perspective – The Electromechanical Meter

By anyone's assessment, traditional electromechanical meters are an amazing piece of engineering work. Refined over a hundred years, the design of a standard residential electricity meter became an impressive combination of economy, accuracy, durability, and simplicity. For this reason, electricity meters have been late in converting to solid state electronics, compared to other common devices.

Three phase commercial and industrial meters, being inherently more complex, were first to make the transition to solid state, beginning in the 1980s, and becoming the norm in the 1990s. As recently as the year 2000, however, some still questioned if and when the simpler residential meter would be replaced by a solid state version, and whether they could attain the same balance of economy and durability.

Now just a decade later, it is clear that this conversion has taken place. Over the last decade, major electricity meter manufacturers have introduced solid state models and discontinued electromechanical production as indicated in Figure 1. This transition diminished the value of both the facilities and the art of traditional meter making and opened the doors of the meter business to new companies.

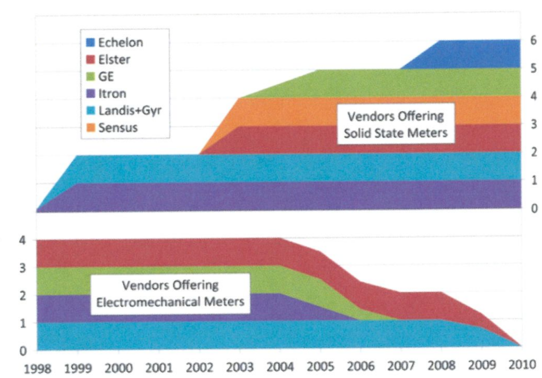


Figure 1 – Replacement of Electromechanical Meter Production with Solid State Versions

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This white paper was prepared by Brian Seal and Mark McGranaghan of Electric Power Research Institute.

Functionality, the Driving Factor for Change

The impetus that finally drove the transition to solid state metering was not cost reduction, nor improvements in service life or reliability, but the need for more advanced functionality. Electromechanical meters, with that familiar spinning disk, did a fine job of measuring total energy consumption, but became extremely complex if required to do anything more. Versions that captured peak demand and versions that measured consumption in multiple time-of-use (TOU) registers have existed, but were not economical for residential purposes.

Today, residential meters are expected to provide a range of measurements, with some including demand, TOU, or even continuous interval data. Some may also be required to keep a record of additional quantities like system voltage – helping utilities maintain quality of service in a world that includes fast-charging electric vehicles and solar generation. In many cases, these solid state meters also include communication electronics that allow the data they measure to be provided to the utility and to the home owner without requiring a meter reader to visit the site.

The Solid State Electricity Meter

Manufacturers who designed the first solid state residential meters understood the challenge they faced. The electromechanical devices they intended to replace held the trust of both utilities and the general public. Because dependable power delivery is critical for the economy, public safety and national security, utilities and regulators have been appropriately cautious in undertaking change. Manufacturers had to not only design a suitable replacement, but also to prove that the new meters could perform and be trusted.

From a utility perspective, several meter performance factors are of concern, including robustness, longevity, cost, and accuracy. But from the homeowner's perspective, the dominant concern is accuracy. If a meter breaks, the utility will fix it. If it becomes obsolete, it is the utility's problem to deal with. If however, a meter is inaccurate in the measurement of energy use, there is a potential that customers could be charged for more energy than they actually used. If the effect were only slight, then it could go undetected. For this reason, accuracy and dependability remain a common concern and a continued focus of dialogue regarding solid state meters.

Keeping in-step with the technology improvements associated with solid state metering, the American National Standards Institute (ANSI) developed new standards with more stringent accuracy requirements during the late 1990s. ANSI C12.20[1] established Accuracy Classes 0.2 and 0.5, with the Class numbers representing the maximum percent metering error at normal loads. Typical residential solid state electricity meters are of Class 0.5, whereas electromechanical meters were typically built to the less stringent ANSI C12.1 standards, as illustrated in Figure 2.[2] In addition, C12.20 compliant meters are required to continue to meter down to 0.1A (24 Watts), whereas C12.1 allowed metering to stop below 0.3A (72 Watts). While metering of such low loads is not likely significant on a residential bill, it is an accuracy improvement nonetheless.

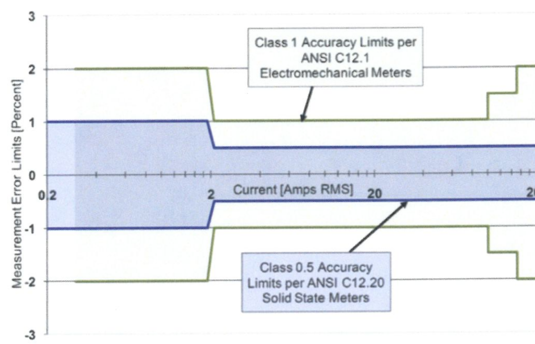


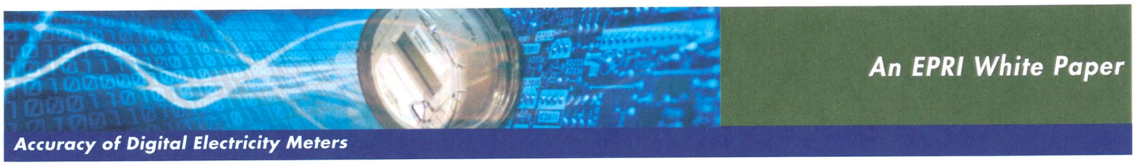
Figure 2 – Accuracy Class Comparison

Manufacturers and utilities use a range of tests and equipment to verify that meters adhere to the ANSI requirements. During the manufacturing process, it is common that each individual meter is calibrated and verified. Once a utility receives new meters, there is often another accuracy test, either on each meter or on a sample basis. States generally establish requirements for how utilities are to check accuracy when new meters are received and at intervals thereafter.

Regardless of their specified performance, solid state meters have been met with mistrust in some early deployments. The most significant of the complaints has been that the meters are simply inaccurate, resulting in higher bills. Given that these new meters are designed to the more stringent ANSI requirements, the factors that may lead to these observations and perceptions are important to understand.

1 American National Standards Institute, 1998, 2002, available from NEMA at http://www.nema.org/stds/c12-20.cfm

2 Data from Metering Standards ANSI C12.1-1988 and ANSI C12.20-2002



Factors in How Digital Meters May Be Perceived

Changes in Billing Periods

The duration of billing periods can vary from month to month, making it difficult to compare one month's bill to the next. If deployment of solid-state meters happens to correspond to a month with a billing period that is particularly long, then customers could incorrectly interpret the associated higher bill with the meter itself. An example of such a long billing period during new meter deployment occurred in January for many customers of Texas utility Oncor. Due to holidays, this billing period was as long as 35 days for some customers.

Complexity of Commissioning New Meters of Any Type

When meters are replaced, and automated reading is instituted, care must be taken to associate the new meter with the correct billing address. Automated tools and processes may be used to aid in this process and are important to guarantee that the right consumption is associated with each residence.

When a meter is replaced, the metering and billing process for that month is more complicated than usual. A closing read from the old meter has to be captured and the associated consumption added to that from the new meter to cover the full billing period. Although the meter replacement process is generally automated to minimize opportunity for human mistakes, the data-splicing process adds complexity and opportunity for error.

If such an error were unreasonably large, it would be recognized as such by both the homeowner and the utility. If, however, a small error occurred, it could be difficult to distinguish from real consumption. It is therefore hypothetically possible that a bill could be in error for the month when the meter replacement occurred, even if both the old and the new meter were accurate.

Connectivity and Estimation

Utility billing systems often have an estimating capability that can apply an algorithm to estimate a customer's bill until an actual read is collected. Historically, such estimation has been used when a manual meter read is missing and any errors in the estimation are corrected in the next bill.

When solid state meters are installed as part of an advanced metering infrastructure program, manual meter reading will halt as the automated process begins. New communication systems may not have good connectivity to every premise at first, so the number and frequency of estimated intervals may be elevated during the first few months after deployment. It is possible that such estimation could result in consumption from one month being billed in another, and hence more variation in bills.

Early Life Failures

Products of many kinds exhibit changes in failure rate over time. As illustrated in Figure 3, these changes often follow a familiar trend. More products tend to fail either very early or very late in the service life of individual devices, with the rate of failure stabilizing at a low level during most of the useful life of the product.

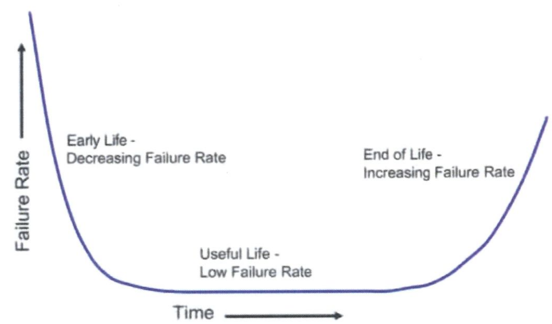
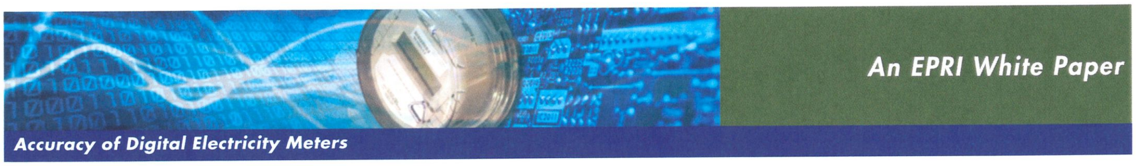


Figure 3 – The Failure Rate Bathtub Curve

Electricity meters are no exception. Both electromechanical and solid state meters have components and assemblies that can result in higher failure rates early in life, and wear-out after their useful life expires. A typical meter population is mature, is centered in the "useful-life" portion of the bathtub curve, and includes only a few new meters installed each year.

Today, the majority of solid state meters put into service are elements of advanced metering systems that are being mass deployed. These deployments can result in an entire meter population that is just a year or two old and therefore may experience sharply increased, but not unexpected, early-life-failure rates. If high registration were among the failure modes of a meter, then an exaggerated percentage of the population could experience higher bills during a new deployment.



Extraordinary Weather

Extraordinary weather can occur at any time. Both record cold winters and hot summers have occurred in North America in recent years and can result in electric bills that are higher than normal. If such events coincide with a deployment of solid-state meters, some may conclude that the new meter is the cause.

One example of how extraordinary weather can result in higher consumption of electricity relates to the use of electric heat pumps used to heat homes in moderate climate zones. These heat pumps, while normally much more efficient than resistive heating, are typically designed with a second stage of electric resistance heat which is triggered when the heat pump itself can no longer satisfy the indoor set point temperature. As outdoor temperature declines, this second stage is called for more frequently. As was the case in many parts of the U.S. this past winter, extreme cold causes abnormally high dependence on second-stage electric heat and in-turn, unusually high electric bills.

Growing Consumption

Average residential electricity consumption has risen for decades, with the addition of increasing numbers and types of electronic devices. Larger televisions, outdoor lighting, and new pools and spas are common additions that can result in notable increases in residential consumption. In other cases, faulty equipment can cause increases. Loss of refrigerant in an HVAC system or a duct that has fallen loose in an attic can cause devices to run excessively, unnoticed until exposed by an electric bill.

If these new purchases or equipment failures happen to coincide with a new electricity meter, one might assume that the resulting bill is the fault of the metering device.

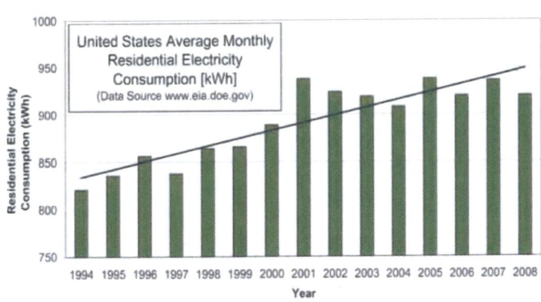


Figure 4 – Residential Electricity Consumption vs. Time

New Rate Structures

New meters may enable new rate structures such as time-of-use or critical peak pricing. These programs offer to make the grid more efficient by motivating consumers to use less energy during times of peak consumption and more when energy is readily available. The improvement in load factor allows for better utilization of assets and, in some cases, deferral of infrastructure upgrades.

While new rate structures may benefit customers on average, individual results depend on the degree to which the consumer heeds the high and low price periods. Customers who select time-based rate plans and do not modify their behavior accordingly could experience higher bills, even though lower bills were possible. Because the new rate plans may go into effect about the same time as a meter-replacement, homeowners could mistakenly associate increased bills with metering errors.

Replacing Defective Meters

Although electromechanical meters are extremely reliable, they do fail. The most common "failure" mode is reduced registration. Anything that increases the drag on the rotating disk can cause a meter to run slow, resulting in reduced bills. Worn gears, corrosion, moisture, dust, and insects can all cause drag and result in an electromechanical meter that does not capture the full consumption of the premise. Failure modes also exist that could cause an electromechanical meter to run fast, but are less common. Figure 5[3] illustrates this effect, based on the average registration versus years-of-service for a sample of 400,000 electromechanical meters.

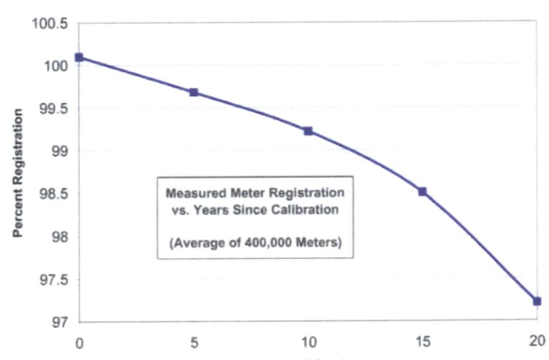
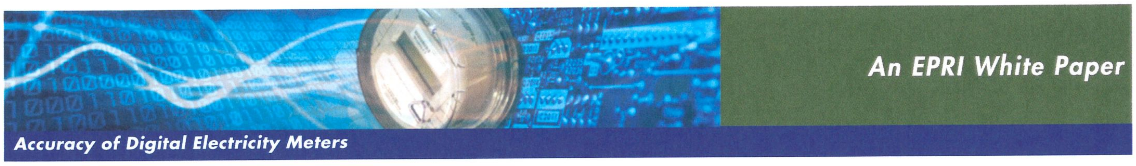
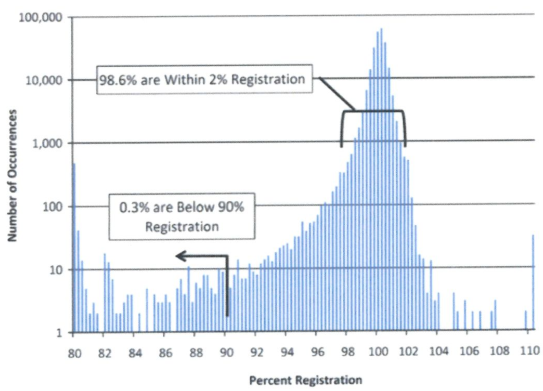


Figure 5 – Electromechanical Meter Registration Loss vs. Time

3 Data by permission from Chapman Metering, www.chapmanmetering.com



When all the meters in a service area are replaced, it is reasonable to expect that some of those taken out of service were inaccurate and running slow. Some may have gradually slowed over many years so that the homeowner never noticed and became accustomed to lower electricity bills. The sudden correction to full accounting and billing could naturally surprise these homeowners and result in questioning of a new meter. While the average meter might be only slightly slow, a few could be significantly so. As indicated in the distribution shown in Figure 6,[4] 0.3% of electromechanical meters tested registered less than 90% of actual consumption. Although 0.3% is small as a percentage, in a service area of a million meters, it represents 3,000 residences that might be under-billed by 10 to 20% prior to a new meter deployment.



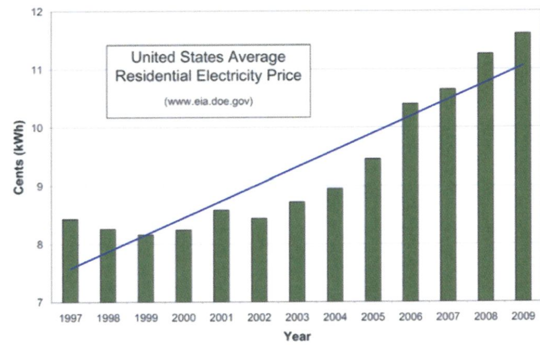
Note the Logarithmic Vertical Scale for Better Resolution

Figure 6 – Electromechanical Meter Registration Distribution

Rising Electricity Costs

Although not the case everywhere, basic energy rates have risen in most areas as a result of increased costs of generating electricity and increased costs of the infrastructure required to deliver electricity to the consumer. As indicated in Figure 7, the average residential electricity price in the United States has increased at an average rate of 0.3 cents per kilowatt-hour per year over the last 12 years. In the event that a rate increase coincides with a rollout of new meters, homeowners experiencing higher bills might conclude that their new meter is in error.

4 Data by permission from Chapman Metering, www.chapmanmetering.com



Note the Exaggerated Vertical Scale

Figure 7 – Average Residential Electricity Price vs. Time

Use of Embedded Software

Electromechanical meters utilized a set of gears and dials to keep a running count of how many times the disk rotated. This assembly, referred to as a "register," maintained a measure of the total power consumption that passed through the meter over time. Like a car's mileage odometer, each gear fed the next so that ten turns of the less significant dial were required to make one turn of the next. These registers had only one input, driven by the spindle of the meter's disk, and could not be moved from one reading to another by any other mechanism. Although simple and mechanical, the result was like a vault, locking-in and protecting the reading of cumulative consumption and immune to sudden shift or loss of data.

Solid state electronic meters are designed to provide this same register function, but using embedded software and non-volatile memory chips as the storage mechanism. Even before the recent deployment of "smart meters," millions of solid state meters have been deployed by utilities since the 1990s and the accuracy of their registration has not been an issue.

Still, as electronic devices, there is the possibility of imperfections in the embedded software or sensitivities in the electronic circuitry. Hypothetically, such imperfections or sensitivities could result in glitches that could affect the meter reading. An error of this nature that occurred only rarely would be difficult to detect prior to field deployment.

With electromechanical meters, modes of failure tend to be permanent. Once a meter or its register fails, due to wear, dust, etc, it is

generally still found to be in a failed state when tested later. Software flaws, on the other hand, could create a transient glitch, leaving a meter that checks-out perfectly afterwards. This possibility complicates the diagnostic process for solid state meters and may make it difficult to discern the root cause of problems.

If it were to occur, the effect of a glitch in a solid state meter or in an AMI system may be mitigated using interval data. Typically, the homeowner's consumption is measured in individual time intervals, such as 15 minutes or 1 hour. This interval data is typically collected by the utility every few hours or daily. Verification of data is thereby made simple because the sum of the entries in each time interval must add up to the total. If a meter's aggregate reading were to suddenly shift, or if a single interval suggested an unrealistic level of consumption, then validation, estimation, and editing software in the utility office could automatically identify the problem and either correct it or flag the issue for customer service.

Voltage Transient Susceptibility

The electronic circuits of solid state meters connect to the AC line to draw operating power and to perform voltage measurement. Although the line voltage is nominally regulated to a stable level, such as 240VAC, transients and surges can occur during events such as electrical storms. A range of electronic clamping and filtering components are used to protect the electronics from these voltage surges, but these components have limitations. The ANSI C12.1 metering standard specifies the magnitude and number of surges that meters must tolerate. In addition, some utilities have instituted surge withstand requirements for their meters that exceed the specification. In any case, surges that exceed the tested limits, either in quantity or magnitude, could cause meter damage or failure.[5]

Electromechanical meters had no digital circuitry. They utilized spark-gaps to control the location of arc-over and to dissipate the energy of typical voltage events. As a result, they were generally immune to standard surge events. This nature is evidenced in the section of ANSI C12.1 that specifies voltage surge testing, but allows that "This test may be omitted for electromechanical meters and registers."[6]

5 *Testing and Performance Assessment for Field Applications of Advanced Meters*, EPRI, Palo Alto, CA. 2009. 1017833

6 ANSI C12.1-2001, Section 4.7.3.3 Test No. 17: *Effect of High Voltage Line Surges*

Summary

Electromechanical meters are dependable products that have served society well. Over a hundred years, their design was optimized so that they provided an excellent combination of simplicity and reliability while providing a single measurement - cumulative energy consumption. Unfortunately, these products did not support the additional functionality needed to integrate customers with a smart grid, such as time of use and real time prices, a range of measured quantities, communication capability, and others.

For these utilities, the transition to solid-state electric meters is therefore not one of choice, but of necessity. Due in part to the large number of announced AMI programs, many homeowners in the United States will likely see their electromechanical meter replaced by a solid-state electronic device in the next five to ten years. During such a transition, there will likely be both real and perceived issues with solid-state designs that need addressing. Care must be taken to consider each case thoroughly and to use sound diagnostic practices to trace each issue to its root cause. Temptations to either blame or exonerate the solid state meter must be resisted. Ideally, each investigation should not only resolve any homeowner concerns, but also discover any product imperfections so that solid-state meter designs may be continually improved. When advanced metering functions are needed, reverting to electromechanical meters is not a viable option.

EPRI Resources

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Smart Distribution Applications and Technologies (Program 124)

1020908 May 2010

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From: Galuska, Tom <tom.galuska@xyleminc.com>
Sent: Thursday, February 13, 2020 10:19 AM
To: Overton, Bruce W <bruce.overton@eversource.com>
Cc: Genardo, Kim <kim.genardo@xyleminc.com>
Subject: RE: Request for assistance - Sensus retrofit ERTs

Bruce,

Sensus has never sold ERTs as we have our own radios that we market. Our meter manufacturing facility does install ERTs on new meters but those ERTS are provided by the end customer or Itron for installation on new meters.

Tom

Thomas Galuska
Senior Product Manager | **Sensus** | **Xylem**
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639 Davis Drive | Morrisville, NC 27560
LinkedIn | Twitter | YouTube | Facebook | Instagram | 3D Tour

From: Overton, Bruce W [mailto:bruce.overton@eversource.com]
Sent: Thursday, February 13, 2020 9:27 AM
To: Galuska, Tom <tom.galuska@xyleminc.com>
Cc: Genardo, Kim <kim.genardo@xyleminc.com>
Subject: RE: Request for assistance - Sensus retrofit ERTs

Thanks Tom. My inquiry is seeking support of our rebuttal to the claim from another party in the Rate Case proceedings. That claim is that in 2013 when we opted to replace our entire mechanical meter population with new AMR meters we should have instead opted to install retrofit ERTs in that population of meters. We are an Itron customer and Itron has already provided us a good deal of information supporting our initial rebuttal to the claim, which is that retrofit ERTs were not an option in 2013 as they ceased to be manufactured in 2005 and they were no longer sold or installed in mechanical meters by 2013. The claimant then responded that Sensus sold them at that time and he even provided that the cost of the unit plus it's installation in a mechanical meter was about $5. Itron does not believe this is true, but cannot speak for Sensus. So I reached out to Sensus and Xylem to try to establish the facts. If you can either confirm or deny that in 2013 Sensus had the ability and would have sold and installed retrofit ERTs into Itron mechanical meters that would be what I am looking for. If a phone conversation would be helpful I'd be happy to arrange that, just let me know.

Thank you.

Bruce

Bruce Overton PMP
Senior Business Project Manager
Eversource
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Cell: (603) 396-4866
Email: bruce.overton@eversource.com

High Level Estimated Capital Costs for full AMI deployment and Opt-Out TVR billing | **AMR vs Retrofit ERT Costs**

Cost Category	General/Generic Functionality of Costs Category	2015 MA From MA Grid Mod filing 1,400,000 Meters	2018 CT From Internal Draft Analysis 1,200,000 Meters	2013 NH From AMR Project Business Case 552,000 Meters AMI Estimated Costs	2013 NH From AMR Project Business Case 552,000 Meters AMR Estimated Costs	2013 NH 552,000 Meters ERT MINIMUM POTENTIAL Estimated Costs	ERT Notes		
Meters	Physical devices. Needed to provide interval based metered usage data	$181,802,000	$192,681,542	$75,364,000	$26,801,000	$1,400,000	**Still have some new meter purchase cost.** Initial purchase of a minimum 35,000 "seed stock" meters.		35,000 * $40
ERTs	Physical devices. Installed in existing devices and configured to transmit monthly consumption reading via RF	N/A	N/A	N/A	Not Estimated	$35,162,400	**Increases** by $8.3M over AMR meter purchase costs. 552,000 meters * $63.70 per meter installed (minimum estimated cost)	$63.70	$48 per ERT $15.70 per ERT for retrofit Note: We paid $32.25 per AMR meter
Remote Disconnect Switch	Physical devices. A specific type of specialized meter.	N/A	N/A	N/A	$740,000	$0	**Functionality no longer available**, and therefore manual reset visit reqiuired to all 48,000 Demand meters each month and no ability to perform "curb side" remote disconnects.		
Meter Installation	Labor, materials, equipment, transportation, warehousing sometimes software. Needed to get new meter from warehousing to installed at service location including return and retirement of old meter.	$29,830,000	Included in "Meters"	$9,172,000	$9,172,000	$12,863,500	**Increases** by estimated $3.7M as it would be Itron's original contract cost **PLUS** the additional costs of round-trip packaging and shipping of 550,000 meters NH to NC for retrofit work.	$3,691,500	552,000 meters / 96 meters per pallet = 5,750 pallets. $200-$250 per pallet one-way averages to $450 per pallet round-trip. $450 * 5,750 = $2,587,500 $2/meter for packaging/handling round trip 552,000 meters = $1,104,000 Total additional installation services costs would be estimated to be $3,691,500 Note: One-Way shipping for new/purchased meters is covered in the price of the meter.
Meter Acceptance Testing	Labor. Standard process to test % of all manufacturer lots for functionality and accuracy.	$5,481,000	Included in "Meters"	$2,238,000	$2,238,000	$2,760,000	**Increases** by estimated $522,000 as 10% of shipments are normally tested upon delivery from vendor and we'd likely increase the percentage due to the retrofit and mechanical meter testing also takes longer than solid state testing.		$40 per AMR meter, $50 per ERT retrofitted meter
Field Communication Equipment	Physical devices and service provider fees. Needed to communicate with AMI meters and transport data from meters to utility IT systems.	$8,500,000	$69,885,068	$25,000,000					
Hardware Testing	Labor. I suspect this would be testing all of the Field Communication equipment and communication paths.	$1,450,000	Not Estimated	Not Estimated					
IT/Systems**		$500,000,000	$134,964	$25,000,000	$845,000	$870,000	**Increase**s by estimated minimum $25,000 to automate "marrying" ERT serial numbers to meter serial numbers in Meter Asset Management System (Power Track) from delivery data supplied by Itron.		
Service Orders	Labor, perhaps hardware and software contracts. Needed to conduct all new meter installations, old meter retirements, and all meter visits/maintenance following installation.	$4,000,000	Not Estimated	Not Estimated	Not Estimated	Not Estimated			
Data Collection/Head End System	Hardware, software contracts, labor. Needed to collect data delivered from meters/field communication equipment.	$6,000,000	$15,122,510	Not Estimated	Not Estimated	Not Estimated			
Data Management & Storage (MDM)	Hardware, software contracts, labor. Needed to manage and process raw meter data and prepare it to be sent to billing systems.	$100,000,000	$47,357,749	Not Estimated	Not Estimated	Not Estimated			
Billing System (New)	Hardware, software contracts, labor. Needed to bill interval meter data and time varying rates.	$373,000,000	Not Estimated	$25,000,000	Not Estimated	Not Estimated			
Billing System (Integration)	Labor primarily, may include software contracts and potentially even hardware. Needed to support continued communication between the new billing system and all of the many peripheral systems which interact with customer and billing information.	Not Estimated	$40,845,418	Not Estimated	Not Estimated	Not Estimated			
Cyber Security	Labor, software contracts, perhaps hardware. Needed to secure customer data from meter to bill.	$10,000,000	$21,160,508	Not Estimated	Not Estimated	Not Estimated			
Customer Data Presentment	Labor, potential software contracts and perhaps even hardware. Needed to make interval data information available to customers via self-service.	$6,000,000	$10,477,838	Not Estimated	Not Estimated	Not Estimated			
Customer Communications	Labor, materials. Needed to proactively inform and educate customers of numerous and varied aspects of the project and change that will impact them in one way or another.	$1,000,000	Not Estimated	Not Estimated	Not Estimated	Not Estimated			
Project Management	Labor. Resources required to plan, manage, monitor and communicate on all aspects of the project and it's many resources and costs.	$21,711,000	Not Estimated	$471,000	$471,000	$471,000	No change		
Organizational Change Management	Labor and materials. Needed to support planned and communicated business process change across the numerous business areas affected by the project.	$32,567,000	Not Estimated	Not Estimated	Not Estimated	Not Estimated			
Stranded Costs	Financial Statement. This represents existing infrastructure investments which will become redundant based on depreciation schedules for capital investments.	$165,000,000	$69,900,000	Not Estimated	Not Estimated	Not Estimated			
Total		**$946,341,000**	**$467,430,632**	**$137,245,000**	**$40,267,000**	**$53,526,900**	**25%**	**<== Project Cost Increase**	

**All In, "Opt-In TVR" IT numbers shown below

Service Orders	$1,000,000
Data Collection	$3,000,000
Data Management & Storage (MDM)	$39,000,000
"Bolt On" Complex Billing System	$26,000,000
Cyber Security	$5,000,000
Customer Data Presentment	$3,000,000
Customer Communications	$1,000,000
Total	**$78,000,000**

7/30/2012

AEP Ohio to Install Automated Meter Reading Equipment throughout Service Territory

CANTON, Ohio, July 30, 2012 – Approximately 204,000 AEP Ohio customers throughout the service territory will receive updated electric meters over the next several months as the company expands the use of automated meter reading (AMR) technology. AMR technology provides a means of reading electric meters remotely.

The company will install radio frequency (RF) meters that send information over radio waves making it possible for meter readers to gather meter information remotely using either a handheld device or a vehicle mounted mobile unit. AMR meters only transmit meter readings which are collected by the meter reader remotely unlike Smart meters which use two-way communications to receive and transmit information between the meter and the utility on a continuous basis.

"The main purpose of installing the AMR meters is to increase meter reading percentages across AEP Ohio service territory and reduce the number of estimated bills. In addition, the decision to strategically increase the use of AMR technology will provide a safer work environment for AEP Ohio employees," said Doug Ickes, AEP Ohio's Manager of Meter Revenue Operations.

The project will start at the beginning of August and should be completed by the end of the first quarter in 2013. AEP Ohio is partnering with Metadigm for the installation of meters across the AEP Ohio service territory. Meter installations will be conducted Monday through Saturday between the hours of 7:00 a.m. and 5:30 p.m. and should go virtually unnoticed by customers. Customers will be notified by mail if their meter will be replaced and a door hanger will be left when the installation is complete.

For more information regarding the Automated Meter Reading (AMR) project, contact our 24 hour Customer Solution Center at 1-800-672-2231 or visit our website at https://aepohio.com/info/projects/AMR/ .

AEP Ohio provides electricity to nearly 1.5 million customers of major AEP subsidiaries Columbus Southern Power Company and Ohio Power Company in Ohio, and Wheeling Power Company in the northern panhandle of West Virginia. AEP Ohio is based in Gahanna, Ohio, and is a unit of American Electric Power.

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GRID EDGE (/ARTICLES/CATEGORY/GRID-EDGE)

The Smart Meter Landscape: 2012 and Beyond

The GTM Scott AMI Market Tracker finds Itron, Silver Spring Networks and Sensus jockeying for top North American smart meter share.

JEFF ST. JOHN | JUNE 18, 2012

The Smart Meter Landscape: 2012 and Beyond

Who has networked the most smart meters in North America?

We've got a lot more clarity into the different ways one could go about answering that question, with the launch of the GTM Scott AMI Market Tracker. The smart grid market service takes a deep dive into the raw numbers of North American smart meter communications deployments, starting with Monday's launch (http://www.greentechmedia.com/articles/read/ami-vendors-ship-3.2-million-units-in-q1-

2012/) of collected figures through the first quarter of 2012.

So, who's winning? The answer to that question, according to the latest and greatest numbers, is 'It depends.'

Let's take the category that most smart grid industry watchers are talking about when they use the term "smart meter." That's an electric meter that's capable of full two-way communications, rather than the older, one-way communicating digital meters known as AMR (automated meter reading).

As for the two-way communicating electric meters, known under the term AMI (advanced metering infrastructure), the current leader in North American deployments is not one of the legacy metering companies, but startup Silver Spring Networks (http://www.greentechmedia.com/articles/read/silver-spring-brings-new-smart-grid-partners-on-board/). As of the first quarter of 2012, the Redwood City, Calif.-based company held a 23 percent market share, leading North American metering heavyweights Itron, at 20 percent, and Sensus, at 19 percent, respectively.

That's quite a feat for the 10-year-old company, which builds networking technology that goes into meters built by other vendors and has landed major deployments with big utilities like Pacific Gas & Electric, Florida Power & Light, Pepco, Oklahoma Gas & Electric (http://www.greentechmedia.com/articles/read/oklahoma-gas-electric-is-not-scared-of-the-home/), Commonwealth Edison (http://www.greentechmedia.com/articles/read/silver-springs-comed-project-4-million-endpoints/) and Progress Energy (http://www.greentechmedia.com/articles/read/distributech-roundup-silver-spring-lands-progress-saic-and-c3-join-forces-a/). Right now it is connecting 22 million meters deployed or under contract, putting it far ahead of other companies that provide similar third-party communications services, such as Trilliant (http://www.greentechmedia.com/articles/read/trilliant-lands-smart-grid-foothold-in-asia/) and SmartSynch (http://www.greentechmedia.com/articles/read/itron-buys-smartsynch/).

The question for Silver Spring is whether it can turn that market share into a profitable (http://www.greentechmedia.com/articles/read/silver-spring-brings-new-smart-grid-partners-on-board/) and growing business. The company has continued to report growing revenues and shrinking losses in the 11 months since it filed plans for an IPO, but it still hasn't pulled the trigger on those plans.

In the meantime, we've got a very different set of North American market leaders when it comes to networking both AMI and AMR electric meters. According to Monday's report, the leader in that category is Itron, the Liberty Lake, Wash.-based metering giant, with more than 46.6 million units in the field as of the first quarter of 2012.

That's nearly twice the deployments of Landis+Gyr, with 23.4 million units, and far ahead of third-place Aclara, a subsidiary of Esco Technologies that's an important contender in North America. Silver Spring's 11.9 million meter chipsets puts it in fourth place in these terms.

Of course, measuring total installed base isn't a good measure of who's been installing the most smart meters lately. In those terms, Itron, which fell behind Silver Spring in annual deployments in 2009, has seen its share pick up in recent years, and retained its lead in the first quarter of 2012.

In second place for the quarter, and among the top three contenders for the past few years, is Sensus, the Raleigh, N.C.-based (http://www.greentechmedia.com/articles/read/from-smart-meters-to-streetlights-sensus-expands-its-network/) metering company with a point-to-multipoint networking topology that differs from the mesh-based networking that Silver Spring and most of its North American competitors rely on. Sensus may be for sale, according to anonymous reports (http://www.greentechmedia.com/articles/read/is-sensus-for-sale/) from October. The company has declined to comment on the report, which set an $800 million to $1 billion price tag for the privately held company.

Another big meter maker that's definitely for sale is Elster (http://www.greentechmedia.com/articles/read/elster-confirms-talks-of-2.3b-aquisition/), the publicly traded German electric, gas and water metering company, which is seeking $2.3 billion for a sale of its assets from majority owner CVC Capital to Melrose PLC (http://www.melroseplc.net/Homepage.html), a British buyout firm. Speculation that a massive grid company like Siemens (http://www.greentechmedia.com/articles/read/siemens-competitors-snapping-up-smart-grid-software/) or ABB may be in the market (http://www.greentechmedia.com/articles/read/abb-ceo-automation-controls-are-next-targets-for-acquisition/) for one or another metering giant has been rampant since last year's $2.3 billion acquisition of Landis+Gyr by Toshiba (http://www.greentechmedia.com/articles/read/as-rumored-toshiba-buys-landis-gyr-for-2.3b-cash/), with Itron and San Jose, Calif.-based Echelon names as some more potential targets.

It's important to note that these new deployments are on a downward trend. Monday's report projects that 13.2 million smart meters will be shipped by the end of 2012, compared to 13.5 million in 2011 and 15.7 million in 2010. That's not surprising, considering that the billions of dollars in stimulus funding for smart grid projects, which helped boost investment to record levels in the past few years, has largely been spent. Even so, there's room for growth. Monday's report estimated that 62 million of the 145 million electric meters in the United States will be "smart" by the end of 2012, leaving more than half of the country awaiting upgrade eventually.

At the same time, water and natural gas utilities need smarter meters as well, and annual deployment figures have been growing, not shrinking, over the past several years. Neptune and Badger, two smart water meter vendors, are among the report's top-ten vendors, alongside AMI/AMR meter providers like Itron, Elster and Sensus. These companies also network gas meters, along with Landis+Gyr and

Aclara.