EXH. CAK-7
DOCKETS UE-190529/UG-190530
UE-190274/UG-190275
2019 PSE GENERAL RATE CASE
WITNESS: CATHERINE A. KOCH

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-190529** **Docket UG-190530 (*Consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferral Accounting and Ratemaking Treatment for Short-life IT/Technology Investment**	**Docket UE-190274** **Docket UG-190275 (*Consolidated*)**

FIRST EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED REBUTTAL TESTIMONY OF

CATHERINE A. KOCH

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 15, 2020

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

Dockets UE-190529 and UG-190530 (*Consolidated*)

Washington Utilities & Transportation Commission v. Puget Sound Energy

RESPONSE OF PUBLIC COUNSEL TO PUGET SOUND ENERGY (PSE)
DATA REQUEST NO. 003

Request No:	003
Directed to:	Public Counsel
Date Received:	11/27/19
Date Produced:	12/10/19
Prepared by:	Paul J. Alvarez
Witnesses:	Paul J. Alvarez

PSE Data Request No. 003 to Public Counsel
(Response Testimony of Paul J. Alvarez, Exh. PJA-1T, at 8:12-16):

The Response Testimony of Paul J. Alvarez on page 8 indicates that "I consider PSE's existing meter equipment to be performing well for equipment designed to last 20 to 30 years (i.e., with an expected failure rate of 1.6 percent to 2.5 percent annually), and the AMR nodes to be performing at a level to be expected for equipment designed to last 10 years on average (i.e., with an expected failure rate of five percent annually)." Please provide:

(a) the basis for the statement that PSE's existing meter equipment is designed to last 20 to 30 years, including any information or documents that address the expected life of the meter equipment;

(b) the basis for the statement that the AMR nodes are designed to last 10 years on average, including any information or documents that address the expected life of the AMR nodes;

(c) the basis for the statements "expected failure rate of 1.6 percent to 2.5 percent annually" and "expected failure rate of five percent annually," including any information or documents supporting these statements or relating in any way to failure rates.

RESPONSE

a) The basis for Mr. Alvarez's statement that existing meter equipment is designed to last 20-30 years is based on his experience in several AMI-related regulatory proceedings. In these proceedings, the useful life for AMI meters is generally an issue. In his experience, utilities typically propose a 15-year or 20-year depreciation period for AMI meters, accompanied by an explanation along the lines of "this is shorter than the depreciation period for traditional meters, as AMI meters are more complex devices than traditional meters." If AMI meters are being depreciated over 15-20 years, according to the typical utility explanation Mr. Alvarez has observed, traditional meters must be being depreciated over periods longer than 15-20 years.

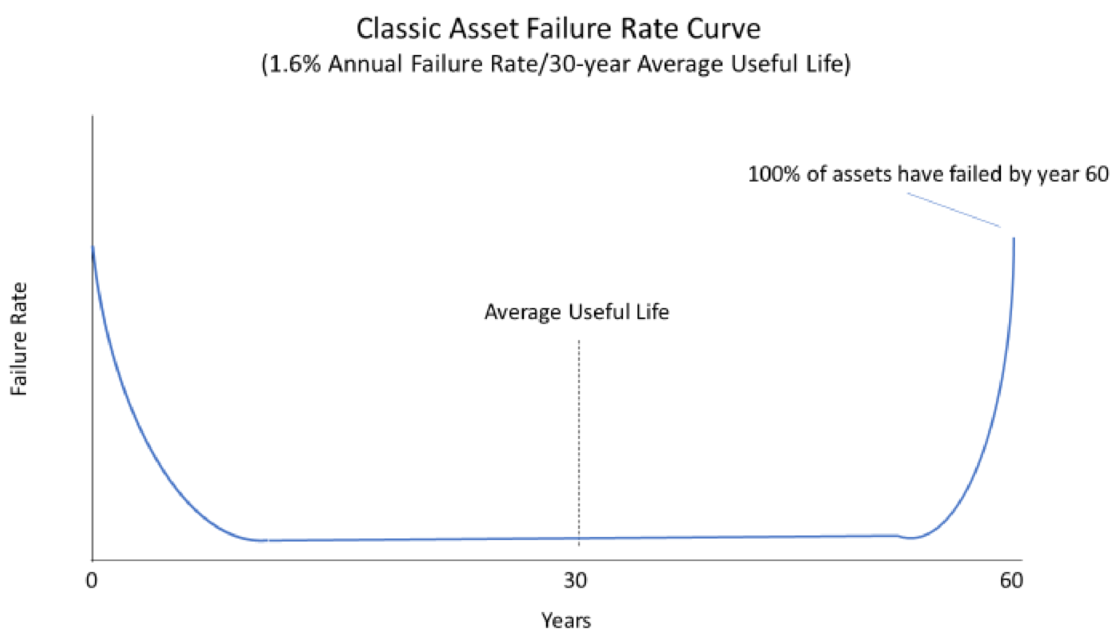
In addition, Mr. Alvarez has researched several distribution plant depreciation studies, finding that traditional meters are commonly depreciated at a rate of two percent to three percent annually, which equates to an average useful life of 16.67 years (100 percent divided by three percent, divided by two to get an average) to 25 years (100 percent divided by two percent divided by two to get an average).

Finally, multiple sources, including manufactures, consultants, and industry experts/researchers, typically cite a 30-year useful life for traditional electric meters:

- "Itron, which formerly produced mechanical meters and now makes smart meters, said that older instruments generally have a lifespan of about 30 years before they start to slow down." (https://www.greentechmedia.com/articles/read/are-traditional-elecricity-meters-accurate)
- "Electromechanical meters have a lifespan of about 30 years" (https://callmepower.com/useful-information/electricity-meter)
- "While electromechanical meters typically lasted 30 years or more, utilities are basing their decisions and cost-benefit analyses for smart metering on the assumption that these new meters will have a lifetime of at least 15 years." (https://blogs.dnvgl.com/energy/determining-smart-meter-lifetimes-to-support-investment-decisions-for-new-metering-infrastructures)
- "Traditional electromechanical (analog) meters have expected useful lifetimes from 20 to 30 years as used as part of cost benefit analyses, but in fact such meters have a proven track record of lasting over 40 years in the field, and analog meters are not prone to catastrophic failures." (https://smartgridawareness.org/2018/09/25/technology-obsolescence-reduces-smart-meter-lifetimes/)
- "Smart meters have shorter life expectancy (5 to 7 years), compared to traditional meters (20 to 30 or 40 years)." (https://www.researchgate.net/publication/325669617_Traditional_Vs_Smart_Electricity_Metering_Systems_A_Brief_Overview)

b) The basis for Mr. Alvarez's statement that the AMR nodes are designed to last 10 years is based on his experience in AMI-related regulatory proceedings in just a few cases. In these proceedings, the useful life for meter communications network nodes only comes up occasionally, as amounts are much smaller than for AMI. However, in the limited cases in which meter communication network node depreciation does come up, utilities typically propose a 10-year depreciation life. In addition, Mr. Alvarez notes that meter communication network nodes are even more complex devices than smart meters, as they generally involve not just communications to/from electric meters, but communications to/from gas meters, and communications/data backhaul to/from the utility, generally through an owned radio network or public cellular networks. Like smart meters, meter communication network nodes also include the additional/updatable firmware and logical software, and sometimes battery back-up systems, which make them more like outdoor computers. And finally, Mr. Alvarez's experience representing consumers in a case in Ohio, in which Duke Energy began replacing its entire meter communications network within just a few years' of the network's deployment, demonstrates the increased technology obsolescence risk associated with meter communications network nodes. This lends credence to 10-year useful life estimates (and confirmed by associated 10-year equipment depreciation periods). This case, along with other issues associated with smart meter and AMR node useful lives/depreciation periods, is summarized in Attachment A to this response.

c) Mr. Alvarez's statements on expected failure rates are based on straightforward math. For example, for any set of meters expected to last 30 years on average, some will fail immediately, and the last ones operating will fail in year 60, as depicted in this chart:



By interpolation, one can calculate that an annual failure rate of 1.6 percent will reflect 100 percent failure by year 60 (100 percent divided by 1.6 percent annually = 60 years). Similarly, one can calculate that an annual failure rate of 2.5 percent reflects 100 percent failure by year 40 (100 percent divided by 2.5 percent annually); using the distribution depicted in the chart above, 100 percent failure in 40 years equates to a 20-year average useful life. Similarly, for a group of assets expected to last 10 years on average, the last ones operating will fail in year 20, yielding a 5 percent annual failure rate (100 percent divided by 5 percent annually = 20 years).

EXHIBIT 1

Smart Grid Awareness
A Website by SkyVision Solutions, Consumer Protection Advocate

Security Risks and Technology Obsolescence Reduce Smart Meter Expected Lifetimes

Posted on September 25, 2018

by K.T. Weaver, SkyVision Solutions, Updated October 15, 2018

Key Article Points:

- Meter manufacturers and most utility companies attempting to justify large-scale smart meter deployments claim useful life values in the range of 15 to 20 years.
- Those individuals and groups who acknowledge that electronic equipment lifetimes are heavily influenced by security issues and technology obsolescence typically forecast much shorter useful lifetimes for smart meters, anywhere from 5 to 15 years with 10 years being a good median value.
- Smart meter useful life values (as used by most utility companies) are based solely on classical reliability analysis that models mechanical failure rates induced by accelerated life testing. These tests are normally conducted by the meter manufacturers themselves.
- Classical mortality factors *and* technology obsolescence determine the *actual* useful life of a smart meter, and they do so simultaneously. Therefore, both should be taken into account. Ignoring technology obsolescence and only considering classical failure rates will result in a gross overstatement of the useful life of a smart meter.
- On balance, the information presented in this article supports the conclusion that the useful life of a utility smart electric meter should not be considered to exceed 10 years. Utility companies planning to deploy smart meters in the future should adjust their project plans and cost benefit analyses accordingly.

Introduction

When utility companies or their consultants conduct business case analyses for smart meter deployments, they typically assign an expected "useful life" [1] for the asset. For example, one utility [2] in its cost benefit analysis (CBA) stated the following:

> "With respect to meter depreciation, Ameren Illinois has reviewed some of the largest AMI deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E to base its AMI deployment on a **useful life** of 20 years for the AMI meter."

> "The timeframe of the primary business case is 20 years for both benefits and costs, which aligns with the estimated **useful life** for the AMI-related investments."
>
> General Assumption: "Meter depreciation time (**useful life**) period used in the model is 20 years" [2]

Based upon my own analysis, most electric utilities have assigned smart meter useful lifetimes in the range of 15 to 20 years. [3]

Traditional electromechanical (analog) meters have expected useful lifetimes from 20 to 30 years as used as part of cost benefit analyses, but in fact such meters have a proven track record of lasting over 40 years in the field, and analog meters are not prone to catastrophic failures. [4] [5] [6]

In October 2015, I published an article indicating that the true useful life of utility digital smart meters is probably in the range of 5 to 10 years based upon the evidence provided in the article, including the Congressional testimony of one utility executive stating that "these devices have a life of between 5 to 7 years." [7]

This current article updates and supplements information presented in the article from October 2015. **On balance, the information presented in this updated article supports the conclusion that the useful life of a utility smart meter should not be considered to exceed 10 years**. Those utilities planning to deploy smart meters in the future should adjust their project plans and CBAs accordingly.

Evidence for Smart Meter Useful Lifetimes Being Less than 15 to 20 Years

Contrary to the large number of utilities assigning smart meter lifetimes in the range of 15 to 20 years [3], there is a considerable amount of evidence that those numbers are overly optimistic. Here is a sampling of that information with appropriate references:

1. In Canada, the Ontario Auditor General's report from 2014 stated: "The estimated useful life for a typical smart meter is 15 years, compared to 40 years for an analog meter. **The distribution companies we consulted said the 15-year estimate is overly optimistic** because smart meters … will likely be **obsolete** by the time they are re-verified as required by the federal agency Measurement Canada **every six to 10 years**." [8]

2. Based upon a comprehensive article at *Smart Energy International* in 2008 on "The AMI Investment Decision":

   > "Considering both the realities of technological **obsolescence** in solid state electronics and telecommunications, and the need to offer incentives for investment in AMI, it would be sensible for utilities and regulatory bodies to **adopt 10 years as the useful life** for AMI."
   >
   > "A **useful life of 10 years for the combined technologies** – metering, telemetry, and data management – would mitigate the risks of technological **obsolescence** and shortfalls in realising expected benefits." [4]

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3. As reported at this website in 2015, a senior vice president of FirstEnergy provided testimony at a Congressional hearing on **cybersecurity** for power systems. At this hearing the corporate officer stated that: "These devices [referring to smart meters] are now computers, and so they have to be maintained. They don't have the life of an existing meter which is 20 to 30 years. **These devices have a life of between 5 to 7 years**." [7]

4. From Nick Hunn, a long-time critic of the Great Britain smart metering project: "Smart meter lifetimes around the world are closer to **10 years** than [the Department for Business, Energy and Industrial Strategy] BEIS' assumption of 25 years, which wipes out the long-term benefits, and means the whole charade will be repeated in **ten years' time**, …" [9]

5. According to BEUC, the European consumer organization:

   > "As smart meters have a rather **limited life expectancy** compared to current mechanical meters, CBAs should take into account the replacement of both current and future meters as well as any additional costs that may occur at the later stage translating into higher expenses for consumers. Without proper analyses, BEUC is highly concerned about the costs that consumers will have to pay without benefiting from the new technology. …
   >
   > While the lifetime of current analogue meters is around 30 years, **it is expected that smart meters will need to be replaced or upgraded after 8 to 15 years**. In order to avoid premature replacements of these meters and ensure they function properly until a possible second deployment wave, modularity of the meters and all the components of systems need to be flexible." [10]

6. According to Dan Lewis, Senior Energy and Infrastructure Adviser at the Institute of Directors in the United Kingdom: "The first thing to say is that this [smart meter] programme is not primarily for consumers. The projected chief beneficiaries, … are the suppliers. They will own the meters and mine the data they produce, while removing a big cost from their balance sheet – manual meter readings and customer billing complaints. Meter manufacturers like the programme too, because the long shelf life of electro-mechanical meters – easily 40 years – would give way to **10 year replacement cycles, interim upgrades and repairs that invariably come with electronic obsolescence**." [11]

7. According to the *New York's Utility Project*, an initiative of the Public Utility Law Project of New York: "Some utilities are now urging faster depreciation (a cost of service allowed by regulators when setting rates) for the new 'smart' equipment assuming a **useful life that is much shorter, perhaps eight to ten years**, more in line with the shorter lifetimes of computers and communications equipment. Others are urging more immediate recovery of their 'smart meter' costs through surcharges to pay for the meters over shorter periods. The utilities' advocacy of shorter depreciation or cost recovery periods suggests a **lack of faith on their part in reliability of the new systems**." [12]

8. From the Edison Electric Institute (EEI) in 2006: "The costs of installing smart meters are not negligible. There are, for example, the costs of replacing the existing electromechanical meter, the **likely shorter useful lives of smart meters**, and the need to replace meters on a 'one-off' (one at a time, not a general deployment) basis. The useful expected life of electronic meters is expected to be about **10 to 15 years**, due to the pace of technological innovation. The useful life of traditional meters is 25-30 years." [13]

9. According to an Accenture report in 2013:

   "While the concept of smart metering for consumer billing purposes is relatively mature, the technology is still evolving. So too are some of the uses of smart metering, with utilities, consumers and third parties all exploring new solutions to extract further value from their investments. Preferred communications technologies are changing, **meter asset life is uncertain** and some smart metering products are constantly evolving."

   The Accenture report contains a table labeled as: "Trends in smart meters and premise-side equipment." In that table it is listed that the smart meter "asset lives [are] considerably shorter than previous meter generation (**five to 15 years**)." [14]

10. According to smart grid workshop sponsored by the Department of Energy and the Vermont Electric Company (VELCO) in 2011: "For a long time, meter technology evolution was relatively slow-moving, and meter device lifecycle problems were not a critical issue. Today, overlapping technology lifecycles is an increasingly important question without an easy answer. Understanding the AMI business case is a case in point: What is the life of the meter now? Typically this was assumed to be 20 years. With the new pace of technological change, **does the assumed lifetime of a meter unit become 10 years**? [15]

11. From the International Electrotechnical Commission (IEC) Strategic Business Plan in 2015: "With traditional electromechanical designs and life spans of several decades, use of hazardous materials and safe disposal of decommissioned meters is not an issue. **Electronic meters may have shorter life cycles due to functional obsolescence**, and some types may contain batteries and other hazardous materials. Therefore, this aspect may be more important in the future." [16]

12. Based upon an energy and finance expert's article at *Engerati* in 2016: "Governments, particularly in the UK, have a poor track record of successfully delivering large IT projects, and the lack of technological maturity increases the threats to a durable implementation. **There are significant risks that smart meters installed today will need to be replaced or upgraded *ahead* of their 12-15 year lifespan, eroding consumer value**." [17]

13. According to a cleantech industry analyst in 2014 on the subject of "advanced metering infrastructure challenges": "New technology risk/future-proof technology: Technology in this field is changing quickly, and the **fear of technological obsolescence is real** for utilities. Advanced metering infrastructure technologies also often do not have mass-scale proven business cases to demonstrate the benefits of implementing AMI." [18]

14. Regarding smart meter installations by Midstate Electric in Oregon, Tom Weller, Midstate Electric engineering supervisor is quoted in the September 2012 issue of *Rural Electric* that: "We based our decision on the assumption that if you buy something today, you may have to **replace it in 10 years due to technical obsolescence, even though the meter still works just fine**." [19]

15. In a 2011 published paper on smart meter lifetime prediction: "For smart meters … not enough long-term experiences [frequently exists] over its failure behaviour to make conclusive statements to reachable verifications of validity. This difficulty is compounded by the fact, that shorter innovation cycles and product

varieties make it more **problematic to find general statements over lifetime prediction of smart meter**." [20]

16. Regarding the smart meters being deployed in Scotland, one training company states: "The Smart Meter Roll-Out will require approximately 12,000-15,000 engineers to replace 53 million meters in 27 million properties by 2020. A relatively **short smart meter life-span of 10-12 years** will ensure sustainable employment for years' to come." [21]

17. Based upon a 2010 article at *EnergyCentral*: "While most smart meters have a possible life of 20 years, and change-out may become appealing for technology reasons after **five to seven years**, most experts believe that **utilities will more than likely replace meters every 10 to 15 years**, taking advantage of new technologies at that time." [22]

18. Here is an early cautionary note from the Ontario Energy Board, Cost Considerations Working Group on its "smart meter initiative" in 2004: "Electronic meters may be less robust and more **vulnerable to technological obsolescence** than mechanical ones presently used. This would imply greater repair/replacement frequency and if failures result in throwaways, as currently happens with many electronic devices, overall costs may be substantially higher." [23]

19. A communication standard called *ZigBee* is many times used by smart meters to enable the use of In-Home Devices (IHDs) by the homeowner. As documented in the 2014 policy report by the Institute of Directors in the UK: "ZigBee chips product lifetimes are unlikely to exceed **four years**. This is much shorter than the duration of the installation stage of the smart meter rollout of 2015-2020. It is considerably shorter than the 12-15 year lifespan of a smart meter and considerably less than the 40 year lifetime of an analogue meter. **Thus, new smart meter re-installations may be required only a few years** into the programme right across the country." [24]

20. As part of preparing for the roll-out of smart meters in the UK, testimony presented in 2011 by Vincent de Rivaz, Chief Executive Officer, EDF Energy included the following: "The **obsolescence** of the new meters will be to the tune of **10 years**, while today it is 25 to 30 years. … Yes, it is a new technology — it is about the digital world — and it is fair that meters move from old technology to the new one. However, new technology, by definition, is more frequently **obsolete**. I am talking about **10 years**, and maybe it will be a bit longer, but not necessarily a lot longer." [25]

21. In 2008, Frontier Economics studied the costs pertaining to smart meters and included a cautionary note regarding the communications components in the meter: "All the manufacturers indicated smart meter design lives of 20 years. However they placed a **caveat** on this around the life of the **communications components**, which they indicated may **have a shorter life**." [26]

22. According to Howard A. Scott, PhD, an independent industry expert: "The metering industry has changed dramatically over the past 25 years. The expected lifetime of a meter has changed from 25 years to closer to **10 years**." [41]

23. In May of 2018, testimony was provided by the Office of the Attorney General for the state of Kentucky in a rate case for the deployment of Advanced Metering Systems for Louisville Gas and Electric Company & Kentucky Utilities Company:

"In discovery from the Companies' recent rate case, the Companies reported that of the 1,677 smart meters installed for Pilot, only 376 are still in service as of December 31, 2016. … The Companies explained in discovery … that most smart meters were replaced due to an LCD display failure. While the smart meter manufacturer has likely corrected such an issue by now, the issue is indicative of the more complex and **sensitive nature of electronic meters** compared to the traditional mechanical type, and why a benefit period of longer than 20 years over-estimates smart meter benefits. It is also worth noting that electric cooperative utilities in Kentucky generally depreciate smart meters over a 15-year period."

"[E]quipment failure is just one of many risks to smart meters' useful lives. There are **technology obsolescence** risks to a long life for any smart meter deployment. In Ohio, Duke Energy has asked for permission to replace the entire AMS system it completed installing just 4 years ago, including 546,000 meters, 370,000 gas meter index modules, and the entire communications network at a cost of $169 million, or about $245 per customer. The utility's request cites many forms of **obsolescence** in its testimony, from field data collectors' cellular service mode (2G/3G) to inflexible software (which is unable to bill time-varying rates), to lack of meter and communications device manufacturer support (acquisitions and bankruptcy). The evaporation of manufacturer support, particularly for meter communication networks, is apparently all too common. Landis + Gyr, the Companies' proposed smart meter and communications network provider, is no longer supporting the TS2 meter communications solution it obtained in a 2006 acquisition, in which many utilities had continued to invest as recently as 2016." [27]

24. In April 2018, a final order was issued by the New Mexico Public Regulation Commission (NMPRC) regarding a request by the Public Service Company of New Mexico (PNM) to deploy smart meters. The request was denied, i.e, "disapproved." [28] [29] PNM had selected 20 years as the expected useful life for the proposed smart meters. As part of the rationale for the denial, the NMPRC stated:

    "PNM's analysis does not include replacement costs that might arise from the **obsolescence** of the meters over their physical service lives and their potential incompatibility with future applications that might be used with the AMI system. As an example of the potential for such costs, Arizona Public Service Company and Texas New Mexico Power Company ("TNMP") were both forced to replace AMI meters that relied upon 2G cellular service after their telecommunications carriers stopped providing 2G service. … PNM's analysis does not include estimates of cost to remediate a hacking incident, such as costs to restore lost data and other billing information." [29]

As one reviews the entries above where useful lifetime values are mentioned, they vary through the range of 5 to 15 years, specifically: 5 to 7, 10, 6 to 10, 10, 8 to 15, 10, 8 to 10, 10 to 15, 5 to 15, 10, less than 12 to 15, 10, 10 to 12, 10 to 15, a few years, 10 years, and 10 years.

A term I often highlighted above was *obsolescence*. This reference is made regarding devices that because of security concerns, electronic components no longer adequately performing the function for which they were created, and/or the lack of communications services support, the devices may become obsolete prior to failing due to "wear out."

The above references present estimates for smart meter lifetimes in the range of 5 to 15 years (with 10 years being a good median value). The values come from a number of reputable sources, including industry experts, consumer organizations, utility consultants, and even utility managers when speaking outside the realm of large utility companies attempting to justify smart meter deployments as part of CBAs. Notably absent from the quotes above are smart meter manufacturers. Before I proceed further to demonstrate why smart meter useful lifetimes are likely less than 15 to 20 years, let me first attempt to show why many utility companies tend to assign the higher values.

The Apparent Basis for 15 to 20 Year Smart Meter Useful Lifetime Numbers

One can partially deduce the origin of optimistic smart meter useful lifetime values from a recent August 2018 ruling by the Public Service Commission for the Commonwealth of Kentucky where the PSC denied the companys' request to deploy smart meters. The utility companies substantiated a 20-year service life value with a two-word email from the manufacturer stating "20 years." From the Order:

> "[T]he **Commission is not persuaded by the Companies' assertion that the meters have a 20-year service life**. The Companies' only evidence to support a 20-year service life of the Landis+Gyr meters is a **two-word email** from a sales representative that indicates a service life of '20 years'. … The Companies offered no further evidence, explanation, or support for a 20-year service life."
>
> "Last, it appears that the Companies applied an **expanded service life** in order to create a cost-benefit scenario favorable to their proposal. Even assuming all of the Companies' other calculations and assumptions are accurate, the **AMS proposal results in a net cost to customers if the meter service life is less than 20 years**." [30]

As we can see, the utility companies based their estimated smart meter useful life solely upon the word of the selected meter manufacturer Landis+Gyr. There is also an implication by the PSC that the utility companies may have purposely applied a 20 year value because it was the only way to arrive at favorable result as part of a cost benefit analysis.

In general, the basis for the more optimistic assigned values of 15 to 20 years for smart meter useful lifetimes is apparently the following:

- Utility reliance on manufacturer claims that smart meters should have useful lifetimes between 15 to 20 years or more.
- A bias towards wanting to rely on optimistic lifetime values in order to arrive at favorable results as part of cost benefit analyses (CBAs).
- A willful or naïve bias towards ignoring fundamental differences between traditional analog utility meters and solid state metering that introduce additional factors which reduce the *actual* useful lifetimes, namely, security risks and technology obsolescence.
- "Echo chamber" bias where current utility CBAs often reference smart meter lifetime values from past CBAs and represent them as "typical" even though they are unproven. Please note, for example, the reference by

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Ameren Illinois as mentioned in the Introduction to this article where Ameren references "Duke Energy, Southern California Edison, DTE, and PG&E to base its AMI deployment on a useful life of 20 years for the AMI meter." [2]

Before addressing manufacturer claims on smart meter useful lifetimes, I want to first address one outlier document where two researchers created a catchy title for a paper presented at a 2001 conference in Asia, entitled, "Exceeding 60-Year Life Expectancy from an Electronic Energy Meter." [31]

I wouldn't normally give this paper the time of day, but a vice president for a utility company participating in the recent Kentucky utility rate case (mentioned above) referenced this single study as part of his testimony to help create the impression that smart meters must have useful lifetimes of at least 20 years or more, stating:

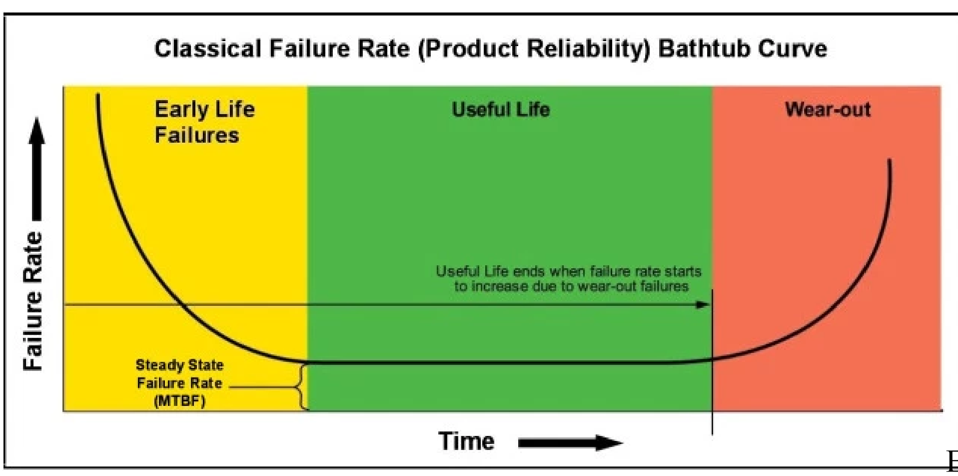
> "In addition, at least one study has suggested than an energy measurement integrated circuit in an AMR meter could have a service life 60 years." [32]

This "one study" stated that *one component* of an electronic utility meter, "an energy measurement IC" [integrated circuit], had sufficiently passed a "high temperature operational lifetest" to be able to achieve a 60-year life expectancy. Although this finding may be interesting to some, the paper itself recognized that the life expectancy of the meter itself (not one component) is a function of the life expectancy of each component in the meter as well as the overall design. The paper merely hypothesized that the results of testing this one component "brings us another step closer to accepting electronic energy meters as the energy meter of the future." I find it disingenuous and deceptive that someone would reference this single study in a utility rate proceeding.

Classical Failure Rates and the Bathtub Curve

Now let me proceed to discuss how smart meter manufacturers attempt to justify estimated smart meter lifetimes in the range of 15 to 20 years. As stated above, the utility companies typically rely on the claims of meter manufacturers for estimated useful lifetime values in order to develop their CBAs.

Reliability engineers model equipment failures with a bathtub shaped curve as shown. There are early life failures that may be due to poor installation or quality control issues; there is a steady state region of the curve where you have relatively constant random failures; finally, there is a point where "wear-outs" begin to occur at an ever-increasing rate signaling the end of the useful life of the device.



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In the area of the bathtub curve where you have a relatively low rate of failures is where manufacturer testing concentrates its efforts to determine the duration of this period of time. Manufacturers perform accelerated life testing (ALT) and deliberately operate a product at an elevated stress condition so that failures can be induced more quickly as compared to waiting for years to observe how a product performs in the field. Stress conditions normally include high and low temperatures as well as temperature cycling, vibration tests, voltage extremes, etc. [5]

In analyzing the data from accelerated testing, engineers typically calculate a quantity called MTBF, or "Mean Time Between Failures." [33] Such is the case for Itron in responding to a question from Fortis BC in Canada pertaining to its OpenWay CENTRON meters in 2012. Refer to the letter/email from Itron that states the following:

> "In response to your query regarding the expected life of the OpenWay CENTRON meters, the expected life is 20 years.
>
> Also, MTBF, or mean time between failure, is a basic measure of a system's reliability. It is typically calculated as the inverse of the failure rate and is represented in units of hours. The higher the MTBF number is, the higher the reliability of the product. The annual failure rate for the OpenWay CENTRON meter is 0.5% for 20 years. Therefore, the MTBF is calculated as 1/0.005 = 200 years or 1,752,000 hours." [34]

Before we analyze whether this type of claim is representative of the *actual* useful life of a smart meter, let us look at one more example. As part of Southern California Edison's cost benefit analysis for smart meters in 2006, it touted having performed its own accelerated testing of *one* "simple" solid state meter:

> "SCE recently completed accelerated life testing on one solid state simple kilowatt hour meter. The meter went through thermal shock and thermal cycle (-50c to +100c) for 80 days. This translates to well over 20-year life using generally accepted useful life modeling procedures." [35]

Personally, I am not impressed with test results from *one* solid state meter that may not even be a "smart meter" that would contain an embedded communication module. Yet Ameren Illinois used this same information several years later as part of its own CBA:

> "Moreover, Southern California Edison conducted product testing that concluded that the meter useful life would be 20 years or more. … [footnoted] SCE Cost Benefit Analysis, Vol 3., December 21, 2006." [2]

In summary, the smart meter useful life values for most utility companies are based upon classical reliability analysis that models mechanical failure rates induced by accelerated life testing. From my analysis I saw no evidence that these values address security risks and technology obsolescence. In addition, there is some question whether the classical testing process adequately addresses communication chips and other accessory components of a smart meter such as LCD displays, weather seals, etc. Certainly communication-related equipment is not normally assigned a 15 to 20 year useful life in other industries.

Evidence for the expected shortened lifetime for communication components is not hard to find. For example, as previously quoted in this article, Frontier Economics stated:

> "All the manufacturers indicated smart meter design lives of 20 years. However they placed a caveat on this around the life of the **communications components**, which they indicated **may have a shorter life**." [26]

According to the *New York's Utility Project*, an initiative of the Public Utility Law Project of New York:

> "**Our experience of computing and communications equipment makes us very concerned that utilities have expectations for reliability that are unfounded**. Limited data on AMI meters confirms our concerns. … legacy meters need repair rarely – so rarely that managers do not even monitor their reliability. Yet new devices based on digital technology with electronic circuit boards, wireless links and many similarities to consumer electronics are widely assumed to be equally durable. We are already monitoring many similar devices and have data showing very poor levels of reliability relative to meters. There is no compelling evidence to believe that the weatherproof versions of computers and communications equipment are going to be more reliable than their interior counterparts." [12]

Security Risks and Technology Obsolescence

We have seen in this article that utility companies primarily base their estimated useful lifetime values on classical reliability analysis taking into account random equipment failures revealed as a result of accelerated life testing. There is some indication the results of such testing may not fully take into account all relevant components of a smart meter, but the results may still meet industry norms for such testing.

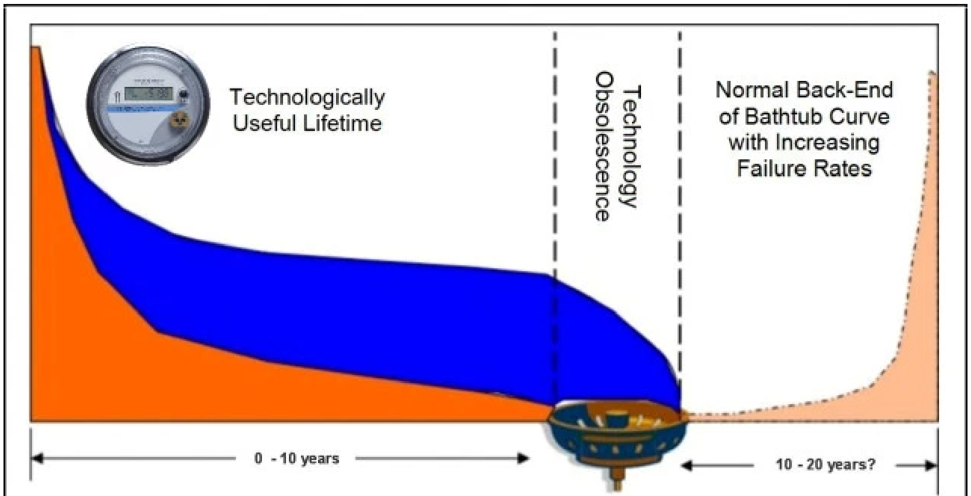
More prominently, however, what utility personnel conveniently ignore is that the *actual* useful life for a smart meter is strongly influenced by other factors such as security risks and technology obsolescence.

Let me now more concisely define "technology obsolescence." *Technology obsolescence* is the loss of value for an asset to perform its function based on the need to substitute one technology for a newer technology. [4]

In some cases the transition to a newer technology may result from a *desire* for more functionality, but the transition may also be *required* due to the lack of technical or logistical support for the older technology. A recent example for smart meters was that some AMI meters deployed within the last few years were dependent on 2G cellular technology. With the phase-out of that technology, the utility is forced to replace the meters with a different technology that is still supported. [29] Such an issue did not arise with traditional analog meters due to the simplicity of design that was not dependent on communications support.

Technology obsolescence and classical mortality factors determine the *actual* useful life of a smart meter, and they do so simultaneously. Therefore, both should be taken into account. Ignoring technology obsolescence and only considering classical failure rates will result in a gross overstatement of the useful life of a smart meter. [36]

In order to better illustrate the influence of technology obsolescence on the useful life of a smart meter as compared to the classical bathtub curve used by meter manufacturers and reliability engineers, refer to the figure that shows a bathtub curve with a "drain." The drain is located at the point in time that electronic components need to be replaced or other factors such as communication support is no longer available for the smart meter. Because of the technology obsolescence "drain," the back-end of the bathtub curve may be a relatively small contributor to the overall costs associated with meter failures. [37]



Life Cycle Bathtub Curve with the Drain of Technology Obsolescence

<u>Security Risks</u>

Security risks could be considered a subset of technology obsolescence, but I considered them a serious enough issue to mention separately. Due to the inclusion of remote disconnects in most smart meters deployed today, a hacking into the AMI system could result in widespread blackouts and catastrophic consequences. I have written a number of articles covering this issue with one of the latest being "Smart Meter Cyber Attacks: A Clear and Present Danger," [38]

My article [7] in October 2015 regarding a possible smart meter life of 5 to 7 years was based upon one utility executive's testimony at a Congressional hearing regarding *cybersecurity* for power systems. The context of the testimony was clear that cybersecurity threats have the ability to shorten the useful life of a smart meter as compared to the classical bathtub curve where end-of-life is solely dependent on wear-out failure rates. How could a cyber threat affect the useful life of a smart meter? All it would take is a serious cybersecurity threat being identified that could not be resolved through an "over-the-air" firmware update.

According to Maxim Integrated:

> "The threats to secure smart meters are varied and evolving. Consequently, there is no single, ultimate solution to security concerns involving electricity networks. Any robust smart meter security strategy must be equipped to deal with threats as they evolve." [39]

According to a published paper on "Identifying the Cyber Attack Surface of the Advanced Metering Infrastructure":

> "[D]eploying such a large number of devices … means that hardware will remain constant for long periods of time. **This contributes to a long lifetime for vulnerabilities even once known, since upgrades are difficult or limited in scope.**"

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> "Therefore, the compromise of even a single smart meter through focused attack or reverse engineering potentially provides access to the AMI network as a whole. … This, coupled with the extensive use of multiple wireless technologies and geographic dispersion, results in an attack surface of unprecedented scale." [40]

The hope on the part of utility companies would be that over-the-air firmware updates would be able to successfully address security threats as they arise. To some extent this may be true, but it is uncertain. The use of over-the-air updates may extend the useful life of a smart meter beyond the 5 to 7 year time frame but probably not much past the ten-year point.

Analysis and Conclusions

Meter manufacturers and most utility companies attempting to justify large-scale smart meter deployments claim useful life values in the range of 15 to 20 years. These values are generally based upon the results of classical reliability analyses which are in turn dependent on determining when equipment failures begin to occur at increasing rates signifying end-of-life "wear-out" of the equipment.

Those individuals and groups who acknowledge that electronic equipment lifetimes are heavily influenced by security issues and technology obsolescence typically forecast much shorter useful lifetimes for smart meters, anywhere from 5 to 15 years with 10 years being a good median value.

It would seem that utility companies ignore such factors as technology obsolescence due to bias, including wanting to use the higher lifetime values to more easily justify meter deployments, and "echo chamber" bias where one utility uses the same values as another peer utility had done in the past.

There is also the possibility that utility companies truly don't understand the fundamental differences between legacy meters and smart meters since it is not objectively credible that useful lifetime values for advanced meters would be solely based upon classical failures rates documented by meter manufacturers. In that regard, it is hoped that this article can shed some light on this most important issue.

In short, utility companies need to do a better job of considering security issues and technology obsolescence and how these factors shorten the estimated useful lifetimes of smart meters. Public utility commissions also need to better educate themselves on these issues, so they don't improperly approve meter deployments that are in fact not reasonable or cost-effective.

Based upon the information and evidence presented in this article, it is clear that security issues and technology obsolescence reduce the estimated useful lifetimes of smart meters as compared to solely considering classical reliability analysis.

It is recommended that useful life values for smart electric meters not be assigned values exceeding 10 years. Utility companies planning to deploy smart meters in the future should adjust their project plans and CBAs accordingly. At the very least, utility companies should be required to specifically identify how their estimated useful lifetime assumptions used in cost benefit analyses have addressed the effects of security issues and technology obsolescence.

Updated Content, October 15, 2018

I recently discovered a blog article [44] published by a major testing laboratory for energy meters which is supportive of the content of this article pertaining to technology obsolescence of utility meters. Here are some excerpts:

> "Traditional electromechanical energy meters have been a familiar installation for both corporate and personal consumers. Increasingly, they are now being replaced with smart energy meters, automatic metering reading (AMR) and advanced metering infrastructures (AMI). While electromechanical meters typically lasted 30 years or more, utilities are basing their decisions and cost-benefit analyses for smart metering on the assumption that these new meters will have a lifetime of at least 15 years. …
>
> **Is 15 years a sensible target for smart meter lifetimes?**
>
> The above discussions and calculations are based on the 15-year lifetime requirement that is common across the industry. While this figure is somewhat shorter than lifetimes expected from traditional meters, it is worth asking whether such a long lifetime requirement is justified for smart meters. After all, such meters:
>
> – Are **subject to significant technological changes**, making it difficult to maintain hardware and software for the first-generation meters, which do not have the advanced functions of newer models
> – Have complex features, such as radio communications and digital displays, which are subject to higher malfunction and failure rates
> – Are similar to other types of information technology, computer equipment and electronic devices in that they are backed by short warranty periods and require significant upgrades or **more frequent replacements as the technology matures**, and
> – Will likely be **obsolete by the time they are re-verified as required by many regulators every 5 to 10 years**
>
> The question of what is a suitable lifetime requirement for smart meters is thus one that is still open to discussion within the industry."

References and Notes

> **Editor's Note: When articles at SkyVision Solutions are published, efforts are made to preserve links for future retrieval and reference, either through direct linkage to this website or through saving the links at http://archive.org/web/. Should you find that a link in the future is not valid or is outdated, please check for an archived version of the webpage or document.**

[1] The "useful life" for a piece of equipment or for a device can be defined as the estimated period of time over which an asset may be reliably used for the purpose intended. The determination of the useful lifetime value can be correlated with an associated depreciation schedule; however, for tax purposes, assets are sometimes allowed to have shorter depreciation times than the values used in the initial business case analysis. [4]

- For example, regarding depreciation schedules, an IRS Memorandum [42] issued in 2012 acknowledges the technological nature of smart meters as "information systems" and would appear to allow utilities to depreciate certain types of smart meters in the U.S. over a period of 5 years for tax purposes. This type of information supports a claim that smart meters likely have useful lifetimes less than 15 to 20 years but does not prove it technically. For business case purposes the true benefit period for a device does not always match its tax depreciation schedule. In some cases governments allow accelerated depreciation schedules as a form of tax incentive for businesses to invest in equipment deemed desirable to support government policy objectives.

The "useful life" values as used in this article refer to "smart meters" commonly deployed today that include 2-way data communications enabled by a processor embedded into the meter electronic circuit board (ECB), frequent meter reads that are time stamped, remote disconnect, net metering, and support for applications such as outage notification. These are the meters that are likely to have useful lifetimes in the neighborhood of ten (10) years as concluded in this article based upon the evidence presented. Earlier solid state meters that may only include one-way communications, i.e., AMRs, and meters with limited functionality, likely have longer useful lifetimes, possibly as high as 15 years. [43]

[2] Ameren Illinois Advanced Metering Infrastructure (AMI) Cost/ Benefit Analysis, June 2012; available at https://skyvisionsolutions.files.wordpress.com/2017/01/ameren-ex-3-1-ami-cost-benefit-analysis.pdf

[3] Refer to the linked document/table for a summary of useful smart meter lifetimes as mentioned in various utility-related documents worldwide. This information substantiates the assertion that most utilities tend to claim that smart meters have a useful life of 15 to 20 years; https://skyvisionsolutions.files.wordpress.com/2018/09/summary-of-smart-meter-useful-life-values.pdf

[4] "The AMI Investment Decision and Lifetimes," by Jin Reilly, June 2008, at https://www.metering.com/the-ami-investment-decision-12636/, where it states: "Traditionally, meters were depreciated over 30 years."

[5] "Accelerated Life Testing of Electronic Revenue Meters," by Venkata Chaluvadi, *All Theses*, 2008, Paper 470; available at http://tigerprints.clemson.edu/all_theses/470/; specifically refer to page 6 where it states: "Traditionally electricity has been measured by the use of electromechanical meters. Such meters have a proven track record of lasting over 40 years in the field, and are not prone to catastrophic failures." Also refer to page 104 where it states: "However, the reliability of electronic components has been a concern and many experts believe that the electronic meters will not survive as long as their electromechanical predecessors."

[6] "Congressional Testimony: Smart meters have a life of 5 to 7 years," SkyVision Solutions Blog Article, October 2015, at https://smartgridawareness.org/2015/10/29/smart-meters-have-life-of-5-to-7-years/, where in Congressional testimony smart meters are compared to traditional analog meters: "They [smart meters] don't have the life of an existing meter which is 20 to 30 years."

[7] "Congressional Testimony: Smart meters have a life of 5 to 7 years," SkyVision Solutions Blog Article, October 2015, at https://smartgridawareness.org/2015/10/29/smart-meters-have-life-of-5-to-7-years/

[8] Ontario Auditor General 2014 Report on the Smart Metering Initiative, available for review at https://skyvisionsolutions.files.wordpress.com/2015/09/ontario-ministry-of-energy-smart-meter-initiative-audit-report.pdf

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[16] From the International Electrotechnical Commission (IEC) Strategic Business Plan for Electrical Energy Measurement and Control, 2015, at https://www.iec.ch/public/miscfiles/sbp/13.pdf

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- Note that the above document by Dr. Scott is undated but is believed to have been written in 2009 based upon the information at https://www.smart-energy.com/regional-news/north-america/u-s-stimulus-plan-smart-grid-funding-should-focus-on-smart-metering/

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[43] "Smart Metering – What Now?," Presentation by Howard A. Scott, Ph.D. of Cognyst Advisors, October 2009; document available at https://wp.me/a3nav9-4dA

Note that the above presentation contains slides with the following information:

- "Expected lifetime of meters is 10 years" (page 57 of 98)
- "Smart Metering capabilities will gradually evolve; equipment placed today may have to be replaced in 5-10 years" (page 90 of 98)

[44] "Determining smart meter lifetimes to support investment decisions for new metering infrastructures," September 19, 2018, at https://blogs.dnvgl.com/energy/determining-smart-meter-lifetimes-to-support-investment-decisions-for-new-metering-infrastructures

PDF Reprint of Original Website Article (added October 14, 2018)

Security Risks and Technology Obsolescence Reduce Smart Meter Expected Lifetimes

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6 Responses to *Security Risks and Technology Obsolescence Reduce Smart Meter Expected Lifetimes*

Fritz *says:*

September 28, 2018 at 04:22

Aside from the technological obsolescence angle, even a 20 year service life for the hardware alone is very optimistic, if not out in out dishonest. Three reasons: (1) All electronic digital meters have a rechargeable battery inside, such as a lithium polymer type, the purpose of this is to keep the memory intact when the power goes out. The life span of these batteries is between 5 and 8 years, this is leaving out environmental factors such as heat, cold, lightning, or system issues such as power surges.
(2) Most, if not all, electronic digital meters, employ electrolytic filter capacitors on the circuit boards. All electrolytic caps have a service life in hours, at a given voltage, and at a given temperature rating,
and theses can very wildly depending on the model of capacitor, the manufacturer, and the country of origin. A few years ago, from about 2005-2010, there was a phenomenon known as the "capacitor plague" where poor quality, and even counterfeit branded electrolytic capacitors were flooding the market from China, working their way into thousands of consumer electronic devices. This was why people had three year old LCD screen TVs and monitors that would refuse to turn on, or similar aged computers with failed power supplies and motherboards.
Even though the counterfeits have largely been weeded out of the supply chain, cheap, poor quality capacitors are still being manufactured, by the same parties. Guess which company supplied Itron with electrolytic caps for their meters? It wasn't Sprague, or Panasonic, or Nichicon, it was Lelon, which is only one knotch above the Chinese mystery brand caps that routinely bulge, and fail.

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(3) There is a certain preoccupation in the modern electronics business to build equipment with multi layered, printed circuit boards, as opposed to the traditional type with one or two sides at most. In constructing electronic devices this way many, if not most of the components end up being surface mounted to foil pads on the board. Now in a controlled environment, such as inside a personal computer, in a home or business, this is not usually an issue, however most electric meters are mounted on the outside of buildings, in the heat, cold, and the weather. Printed circuit boards, components, and solder comprise dissimilar materials, copper, lead, plastics, tin, gold, and all react differently to heat, cold, moisture, which can cause these surface mounted solder joints to break down over time, even faster with lead free solder.
(4) To be in service outside the boards in these meters should be potted, that is coated in a weather resistant coating, this would be routine in automotive electronics, but is non existent in many digital meters, at least the Itron models. To make matters even worse, the meters that Itron produces are not even weather tight, there is no gasket between the plastic dome, and the base of the meter, if there is a lot of rain, or slushy snow, you can see condensation, and sometimes standing water inside the meter housing. How can any electrical device be expected to live out a 20 year lifespan whist being infiltrated by water for several months out of the year, the answer is that they can't, things will oxidize, corrode, and inevitably fail.

Reply

SkyVision Solutions *says:*

September 28, 2018 at 22:03

Thanks for your information and feedback. Most of what you say may be true, but I know of several models of solid state meters that do not contain batteries. Some basically have a flash memory that stores the current memory upon power failure. Those meters that are part of a mesh network maintain time as synchronized through the network communications. Those meters capable of outage notification many times contain a supercapacitor (in lieu of a battery) which powers the meter just long enough to get out a last gasp notification.

Reply

Fritz *says:*

October 1, 2018 at 04:38

I'm speaking of the Itron Open Way dumb "smart" meters in particular, there are no supercaps in those, and they use a mesh network. When the power goes off where I am, it usually goes off for at least three hours at a time, without the battery they would pretty much loose their memory. The last gasp would not work as the usage data is only collected twice per day, (I'm not speaking of the meters communicating with each other, just between the meters and the power co. office in my area) which takes about 4 hours each time, and if the whole network is dead there isn't any place for it to go.
From what I can see Itron is a company run by bean counters, not engineers, which is not surprising given that they were built through acquisition, if they can save $.005 cents per meter they will do it. These are guys that won't even install gaskets between the dome and the baseplates of their meters, if a flash drive or a good quality supercap costs more then a battery, the battery wins. You should see what their rates of pay are for engineers, they start at $40k and top out at $60K, one thing's for sure, the best talent isn't looking there for work! I have no idea which companies would add the backups you speak of, G.E maybe? Actually I had more then three reasons why their life will not anywhere near 20 years, I had five but only remembered to jot down four. The fourth reason is the serge protectors that many use, if they use a metal oxide varistor or MOV type serge protector, those have a service life as well. If they are in a region that receives a lot of lightning strikes and power surges, the MOV is damaged slightly each time. After a certain period of time the MOV wears out, no longer dissipate the surges, overheats, shorts out, and burns up. There was a problem with these that surfaced a few years ago in serge protected computer power bars, the MOVs would wear out, short, burn up, and light the plastic of the power bar on fire. The MOV in an Itron Open Way meter is mounted right to one of the circuit boards, NOT smart!

SkyVision Solutions *says:*

October 2, 2018 at 10:50

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OK, general good info, except where you say:

"When the power goes off where I am, it usually goes off for at least three hours at a time, without the battery they would pretty much loose their memory. The last gasp would not work as the usage data is only collected twice per day, …"

Many older smart meters certainly contain batteries but I would say that most newer ones don't. When you have "flash" memory, the memory (and stored data) is not lost when there is a power loss. The meter will lose track of current time but that is re-established with the network when power is resumed.

The last gasp outage notification I mentioned is just for letting the utility know that a specific customer is without power, not to transfer any usage data. Last gasps (outage notifications) are not very effective, but the utility companies promote them to consumer as a benefit. I have written about them at https://smartgridawareness.org/2015/04/30/customer-calls-not-smart-meters-still-primary-source-of-power-outage-notification-for-utilities/

Take Back Your Power *says:*

September 25, 2018 at 14:33

10 years is WAY optimistic. 5-7 years, or even less in some cases, is realistic, in terms of what we're seeing (utilities' upgrading schedule), and the utility rep's testimony per your 2015 article here: https://smartgridawareness.org/2015/10/29/smart-meters-have-life-of-5-to-7-years/ (clip also at 10m40sec of Take Back Your Power: https://youtu.be/8ZTiT9ZSg3Q?t=10m40s)

Reply

SkyVision Solutions *says:*

September 25, 2018 at 15:05

As part of my article in 2015, I included the Congressional testimony of one corporate officer referring to a 5 to 7 year lifetime. The person did not fully explain his rationale for his statements, but it is likely that he would say for cyber threats "over-the-air" firmware updates could extend the life of the smart meter to some extent, i.e., by a few years. The guy was after all speaking at a hearing on cyber threats. I am sure he did not mean that all his company's meters were going to fall apart or stop working after 5 to 7 years. This is a more complex issue than that.

For this latest more comprehensive article I spent nearly a year collecting the source information and references. I averaged the values from about 20 different sources to arrive at the 10-year number (from what I judged objective sources). The Congressional hearing statement reference for a 5 to 7 year lifetime is one of those objective sources used in this latest article.

To just claim the 5 to 7 years lifetime number or maybe even less is more realistic as a general characterization is not really plausible. I have had a smart meter on my home now for over 5 years as well as everyone in town; there is no great rush to yet replace them. But the issue is the high risk of obsolescence within about 10 years or so from deployment and that is really what this new article is about.

As actually stated in my newest article regarding the 5 to 7 year value mentioned at Congressional hearing: "My article in October 2015 regarding a possible smart meter life of 5 to 7 years was based upon one utility executive's testimony at a Congressional hearing regarding cybersecurity for power systems. The context of the testimony was clear that cybersecurity threats have the ability to shorten the useful life of a smart meter as compared to the classical bathtub curve where end-of-life is solely dependent on wear-out failure rates. How could a cyber threat affect the useful life of a smart meter? All it would take is a serious cybersecurity threat being identified that could not be resolved through an 'over-the-air' firmware update."

"The hope on the part of utility companies would be that over-the-air firmware updates would be able to successfully address security threats as they arise. To some extent this may be true, but it is uncertain. The use of over-the-air updates may extend the useful life of a smart meter beyond the 5 to 7 year time frame but probably not much past the ten-year point."

The conclusions reached in the above excerpt are consistent with the results of my year of research on this topic of smart meter lifetimes.

Reply

EXHIBIT 2

Alternative & Renewable Energy Tax Newsalert

IRS rules certain smart meters can be depreciated over five years

November 9, 2012

On November 2, the IRS released Taxpayer Advice Memorandum 201244015 that concludes certain utility smart meters are six-year property and thus eligible for five-year depreciation. This conclusion was contrary to the arguments advanced by the IRS examination personnel responsible for the taxpayer's case.

The taxpayer, a reulgated utility, replaced its decades-old standard electromechanical meters with new smart meters. The new meters are capable of real-time monitoring of electicity usage, as well as providing information on power outages and other data,

The issue raised is whether the meters are considered to be part of Rev. Proc. 87-56 asset class 00.12 and thus are six-year property, or as qualified technological equipment under §168(i)(2), in which case the asset life would relate to the utility's distribution assets.

Asset class 00.12 includes information systems such as computers and peripheral equipment used in administering normal business transactions and the maintenance, retrieval, and analysis of business records. It does not include equipment that is an integral part of other capital equipment that is included in other classes of economic activity.

The IRS agreed with the taxpayer that the meter is used in administering normal business transactions and in the maintenance, retrieval, and analysis of taxpayer's business records during the year at issue.

The IRS also determined that the meter is a computer under asset class 00.12 of Rev. Proc. 87-56 because it shares common features with computers such as a central processing unit with storage and other logic functions. In addition, it is programmable, electronically activated, and is capable of detecting energy tampering or service quality issues.

The IRS found the exceptions to asset class 00.12 inapplicable because the meter is not used primarily for process or production control, switching, channeling, or automating distributive trades and services such as those made by point-of-sale computer systems.

The IRS concluded that the meter has a class life of six years because it is clearly includable in asset class 00.12.

Finally, the IRS noted that this ruling could be modified or revoked if regulations addressing this issue are subsequently released by the Treasury Department. However, the IRS also noted that such modification or revocation may not be applied retroactively if the taxpayer meets certain criteria.

PwC Observations

The ruling here clearly provides beneficial treatment of smart meters in the factual circumstances set out. Many utilities are installing smart meters and a favorable asset life is likely a welcome development. In addition, five-year depreciation is consistent with the treatment of other clean energy property such as renewable energy assets.

For more information:

For prior alerts on alternative and renewable energy tax issues, please see our news archive. In addition to the Alternative & Renewable Energy Tax News alert, PwC also publishes a cross-disciplinary news alert providing updates on cleantech, sustainable development, and the business impacts of US climate and energy policy. For further information and to sign up for these alerts, click here.

For more information about using energy tax incentives to meet your renewable energy goals, please contact a member of PwC's Sustainable Business Solutions tax team:

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INTERNAL REVENUE SERVICE
NATIONAL OFFICE TECHNICAL ADVICE MEMORANDUM

September 16, 2011

Number: **201244015**
Release Date: 11/2/2012

Third Party Communication: None
Date of Communication: Not Applicable

Index (UIL) No.: 168.20-00
CASE-MIS No.: TAM-112103-11

Taxpayer's Name:
Taxpayer's Address:

Taxpayer's Identification No:
Year(s) Involved:
Date of Conference:

LEGEND:

Taxpayer =
Parent =

Regulatory Body =
Year 1 =
Year 2 =
<u>A</u> =
<u>B</u> =
<u>C</u> =
<u>D</u> =
<u>E</u> =
<u>F</u> =
<u>G</u> =
<u>H</u> =
<u>I</u> =

J	=
Meter 1	=
Meter 2	=
Model A	=
Model B	=
Computer	=

ISSUE:

For purposes of § 168 of the Internal Revenue Code, are Meter 2, a smart electric meter, and associated equipment placed in service by Taxpayer after October 3, 2008, classified as qualified smart electric meters under § 168(e)(3)(D)(iii) or are Meter 2 and associated equipment placed in service by Taxpayer during the year at issue classified as qualified technological equipment under § 168(e)(3)(B)(iv) or in asset class 00.12, Information Systems, of Rev. Proc. 87-56, 1987-2 C.B. 674, as clarified and modified by Rev. Proc. 88-22, 1988-1 C.B. 785?

CONCLUSION:

For purposes of § 168, Meter 2 and associated equipment placed in service by Taxpayer during the year at issue are classified in asset class 00.12 of Rev. Proc. 87-56 and, therefore, have a class life of 6 years. Accordingly, Meter 2 and associated equipment placed in service by Taxpayer after October 3, 2008, are not qualified smart electric meters under § 168(e)(3)(D)(iii).

FACTS:

Taxpayer is the subsidiary of Parent and operates as a utility company subject to regulation by the Regulatory Body.

For decades, Taxpayer has used standard electromechanical meters to measure customers' electrical usage. This longstanding technology uses a small motor to spin a disc, which is connected to gears and a set of dials that record cumulative kilowatt-hours ("KWH") of power that have passed through the meter. Historically, each meter was visited regularly, typically at monthly intervals, by a person who would read the meter and write down in a book the cumulative number of KWH of power shown on the meter, the date and location. That data was then passed to Taxpayer's central billing office. At the central billing office, Taxpayer's personnel would input the data into the mainframe computer, which would calculate the customer's electric usage in KWH since the last reading by subtracting the current reading from the prior reading, multiply the KWH usage times a rate (tariff) to arrive at the amount owed by the customer for the current period usage, and prepare a bill that would be mailed to the customer.

In Year 1, the data collection system was improved when Taxpayer began using portable handheld data log devices that its meter readers used to manually record the monthly readings from the standard meters. At the end of each day, the meter readings recorded on these devices were electronically transferred directly to the central office computers – saving time and labor, and minimizing errors. These devices also were used to record detailed information regarding customer accounts for each route in support of the next day's meter reading activity.

In Year 2, Taxpayer proposed the system-wide installation of a new set of electromechanical meters equipped with an optical scanner and a communication device. Using these meters, Taxpayer proposed to eliminate manual meter reads, saving costs and reducing billing errors. Taxpayer also envisioned operational cost savings through the ability to better locate outages because the meters were designed to be "pinged" to determine whether the meter was receiving power. Pinging involves the sending of a signal to a specific electronic address, which is designed to elicit a response if the meter is then operable (i.e., receiving electricity). These meters, known as Meter 1, utilized Taxpayer's power lines to carry the meter data signal back to substations, where it was gathered and transmitted automatically to Taxpayer's central computers.

The optical scanner and communication device on Meter 1 also gave Taxpayer the capability to implement time of use ("TOU") pricing. The optical scanning device was designed to read the mechanical rotations of a disc within the meter every hour and to send a signal of such usage to Taxpayer's central office every A hours. With its central billing computers and data systems, Taxpayer could then take the hourly usage data received from the meters and calculate customer bills using TOU rates.

While Taxpayer was in the process of installing Meter 1, the technology and capability of meters evolved. Because of the technological advances and the significantly enhanced capability of this new meter technology, Taxpayer decided that it would no longer continue to replace existing meters with Meter 1. Instead, Taxpayer sought and received permission from the Regulatory Body to begin installation of the new technologically advanced meters, known as Meter 2.

Meter 1 and Meter 2 are both approximately the same size and consist of a round dome clear glass cover, on a round base, which has four metal prongs at the bottom that insert into slots in the meter socket. When the meter is inserted into the socket a circuit is completed with half the prongs connecting to a receptacle on the utility side of the meter and the other prongs connecting to a receptacle on the customer's side of the meter, allowing electricity to flow from the power source on the utility's side of the meter into the customer's electric system. Both Meter 1 and Meter 2 are electrically activated and readily removable.

Meter 1 is a variation of an electromechanical induction meter that operates by counting the revolutions of an aluminum disc that is made to rotate by electrical fields at a speed proportional to the energy usage. The aluminum disc is supported by a spindle that has a worm gear that drives an analog register. The register is a series of dials that record the amount of electric energy used and can be viewed through the glass dome. Meter 1 also has an optical scanning device that reads the rotation of the aluminum disc by observing a line on the disc each time it makes a rotation. The observation of disc revolutions is sent back to the utility over the electric lines and is used to measure the electric energy usage.

The internal components of Meter 2 differ from those of Meter 1. Meter 2 measures electric energy usage using a solid state sensor and microprocessor, which then displays electric usage on a digital liquid crystal display screen, rather than through a direct mechanical measurement of energy usage that is registered on an analog dial.

Taxpayer has installed two models of Meter 2: Model A and Model B. Both models can be programmed. From a practical standpoint, these two models have essentially the same metrology components and perform essentially the same functions.

Inside the case of Meter 2 are various components that are designed to accomplish the following four functions:

1. Metrology, which senses and measures electric current, converts that measurement to a signal that goes to a register that records the measurement, and displays the accumulated amount of electricity used. The metrology portion of Meter 2 consists of two major components – a base and electronic module.

The base includes a precision current transformer that senses the current. The transformer reduces the current (amperage) and voltage to two sensors, which provide separate analog signals of voltage and amperage.

The electronic module has the metering circuitry, including a microcontroller, which enables energy accumulation and contains calibration information. The meter chips contained on the electronic module convert analog signals of current and voltage from the sensors into a digital form. The microcontroller calculates accumulated energy (volts multiplied by amps over time) and maintains the energy consumption for display. It uses non-volatile memory to store the metering data, including energy used, voltage, and amperage. The non-volatile memory does not require a battery to maintain information when power is unavailable. The Model A of Meter 2 contains memory of <u>B</u> bytes and Model B of Meter 2 contains memory of <u>C</u> bytes.

2. An advanced metering initiative (AMI) communications module that provides two-way wireless signal at a radio frequency of <u>D</u> megahertz. The AMI communications module of Meter 2 also is referred to as the local area networking (LAN) part of the

meter. It is electronic circuitry located on the Network Interface Card (NIC) within Meter 2, which is capable of using internet protocols addressing. Taxpayer uses this component to receive frequent usage readings (every few minutes) from the metrology parts of the meter and to send that data automatically to a data gathering system that leads to Taxpayer's central database. The AMI also has the capability, in conjunction with the meter, to control the disconnect switch.

The NIC is integrated with the meter at the factory using "through-pin" and serial port connections. The NIC includes an E processor with a speed of F MHz and contains A MB of flash storage capacity and G MB of random access memory (RAM), which is roughly comparable in terms of processing and storage capacity to early desktop computers, such as a Computer, which had a H MHz processor and similar amounts of storage.

The components of the NIC have the potential to perform some calculations that are now done on central office mainframe computers. For example, the NIC is capable of multiplying electrical usage by the tariff rate to calculate the customer's bill.

3. A Home Area Network (HAN) module to communicate from the meter to the customer's display or computer. It uses a separate radio circuit at I gigahertz frequency. The HAN was not functioning during the year at issue. However, the HAN is designed to be used by customers to access their account online or view their electricity usage data on a digital display or monitor, rather than waiting for a monthly bill.

4. A disconnect switch that can be programmed or directed by Taxpayer's credit collection and billing department to interrupt, initiate, or restore electric service by remote activation by the AMI communication module. The disconnect switch also can be programmed by the AMI communication module to perform a power-limiting function; that is, to shut off the service temporarily if the power usage through the meter exceeds a certain flow rate (amperage). While Meter 2 had the capability to operate the disconnect switch during the year at issue, the disconnect switch was not functioning then because it had not been programmed to do so.

These functions cannot be used and are not accessible for general computing uses in the same way as a personal computer. There is no connection jack, USB or other port, input keypad, computer display monitor, or physical connection with an external monitor. However, Taxpayer can program Meter 2 remotely through the wireless connectivity and internet protocols. This same wireless connectivity and internet protocol could potentially be used to give Meter 2 the capability to send information to display monitors at the customers' locations or Taxpayer's offices, where the information could be viewed. This potential function was not used during the year at issue.

While the above functions are integrated, should the AMI communications module, HAN module, and/or disconnect switch functions fail, Meter 2 would continue to measure the electrical current and store usage information in the memory register.

Meter 2 does not have an independent power source (battery) so that if power is unavailable, the meter cannot function. However, stored information is not lost in the absence of power. Meter 2 records and stores usage data in hourly increments for J days. Meter 2 is designed to continue to perform various functions (e.g., LAN communications), even though the disconnect switch is engaged and no power is flowing to the customer.

As previously mentioned, Taxpayer uses the LAN part of Meter 2 to receive frequent usage readings from the metrology parts of the meter and to send that data automatically to a data gathering system that leads to Taxpayer's central database. The equipment necessary for the automated relay of data between Meter 2 and Taxpayer's central database consists of wireless receiving and relay devices; that is, eBridges, relays, and access points (hereinafter, this equipment is referred collectively to as the "associated equipment"). Every one of these devices has embedded in it a microprocessor, which is the same one used in Meter 2. The associated equipment gathers data from many customers and feeds it to a specialized Meter Data Management (MDM) centralized computer system. Upon receiving the raw data from the Meter 2 system, the MDM checks for errors and then processes and translates the raw data into a form compatible with Taxpayer's existing customer care and billing central database. The other functions of the MDM include the monitoring of the system for meter failures and power outages. The MDM and customer care and billing central database are not dependent upon the type of meter used.

Meter 2 performs additional functions than Meter 1. The LAN part of Meter 2 and its associated equipment is designed to provide real-time usage data and other real-time information on a two-way basis between Meter 2 and Taxpayer's central billing office. Meter 2 also is designed through the HAN module to communicate information and other data to Taxpayer's customers. Finally, Meter 2 also is programmable so that it can be adapted to other information uses as conditions warrant. These capabilities will permit both Taxpayer and the customer to regulate electric usage by integrating customer billing and rate design with new dynamic rate structures and demand response programs.

Meter 2, like Meter 1, can be read remotely to enable more frequent meter reads needed to implement TOU rates. Meter 2, however, has enhanced capacity because it can communicate in real time rather than in hourly intervals. In addition, Meter 2 has the capability to read and record bi-directional power flows when a customer receives power and provides power at different times rather than simply measuring the net of the power flows over a meter reading time segment (e.g., over a segment that consists of several hours). Meter 2 then subtracts any customer-supplied power from Taxpayer-supplied power thereby converting the bi-directional metering data to net metering data. This capability is available through use of the computerized memory register. The bi-directional metering data also includes detailed time-of-day data that will allow TOU pricing.

LAW AND ANALYSIS:

Section 167(a) provides that there shall be allowed as a depreciation deduction a reasonable allowance for the exhaustion, wear and tear (including a reasonable allowance for obsolescence) of property used in a taxpayer's trade or business.

The depreciation deduction provided by § 167(a) for tangible property placed in service after 1986 generally is determined under § 168. This section prescribes two methods of accounting for determining depreciation allowances. One method is the general depreciation system in § 168(a) and the other method is the alternative depreciation system in § 168(g). Under either depreciation system, the depreciation deduction is computed by using a prescribed depreciation method, recovery period, and convention.

For purposes of either § 168(a) or § 168(g), the applicable recovery period is determined by reference to class life or by statute. Section 168(i)(1) defines the term "class life" as meaning the class life (if any) that would be applicable with respect to any property as of January 1, 1986, under § 167(m) (determined without regard to § 167(m)(4) and as if the taxpayer had made an election under § 167(m)) as in effect on the day before the date of enactment of the Revenue Reconciliation Act of 1990. Former § 167(m) provided that in the case of a taxpayer who elected the Class Life Asset Depreciation Range system of depreciation, the depreciation allowance was based on the class life prescribed by the Secretary that reasonably reflected the anticipated useful life of that class of property to the industry or other group.

Section 1.167(a)-11(b)(4)(iii)(b) of the Income Tax Regulations provides rules for classifying property under former § 167(m). Under § 1.167(a)-11(b)(4)(iii)(b), property is classified according to primary use even though the activity in which such property is primarily used is insubstantial in relation to all the taxpayer's activity.

Rev. Proc. 87-56 sets forth the class lives of property subject to depreciation under § 168. This revenue procedure establishes two broad categories of depreciable assets: (1) asset classes 00.11 through 00.4 that consist of specific depreciable assets used in all business activities; and (2) asset classes 01.1 through 80.0 that consist of depreciable assets used in specific business activities. An asset that falls within both an asset group (that is, asset classes 00.11 through 00.4) and an activity group (that is, asset classes 01.1 through 80.0) would be classified in the asset group. See Norwest Corp. & Subs. v. Commissioner, 111 T.C. 105, 156-64 (1998).

Asset class 00.12, Information Systems, of Rev. Proc. 87-56 includes computers and their peripheral equipment used in administering normal business transactions and the maintenance of business records, their retrieval and analysis. Assets included in this asset class have a 6-year class life. Asset class 00.12 defines information systems as:

1) Computers: A computer is a programmable electronically activated device capable of accepting information, applying prescribed processes to the information, and supplying the results of these processes with or without human intervention. It usually consists of a central processing unit containing extensive storage, logic, arithmetic, and control capabilities. Adding machines, electronic desk calculators, etc., and other equipment described in asset class 00.13 are excluded from this category.

2) Peripheral equipment consists of the auxiliary machines which are designed to be placed under control of the central processing unit. Nonlimiting examples are: card readers, card punches, magnetic feed tapes, high speed printers, optical character readers, teleprinters, terminals, tape drives, disc drives, disc files, disc packs, visual image projector tubes, card sorters, plotters, and collators. Peripheral equipment may be used on-line or off-line.

Asset class 00.12 does not include equipment that is an integral part of other capital equipment that is included in other classes of economic activity, i.e., computers used primarily for process or production control, switching, channeling, and automating distributive trades and services such as point of sale computer systems. Asset class 00.12 also does not include equipment of a kind used primarily for amusement or entertainment of the user.

Asset class 49.14, Electric Utility Transmission and Distribution Plant, of Rev. Proc. 87-56, includes assets used in the transmission and distribution of electricity for sale and related land improvements. Assets included in this asset class have a 30-year class life.

Several appellate decisions discuss the "primary use" standard for asset classification under § 1.167(a)-11(b)(4)(ii)(b). See, e.g., Clajon Gas Co, L.P. v. Commissioner, 354 F. 3d 786 (8th Cir. 2004). Courts have concluded that the actual purpose and function of an asset determines its asset class (a use-driven functional standard) rather than the terminology used to describe an asset by its owners or others.

The Tax Court in PPL Corporation v. Commissioner, 135 T.C. 176 (2010), concluded that street light assets are not assets used in the distribution of electricity and, thus, not included in asset class 49.14 of Rev. Proc. 87-56. In reaching its conclusion, the Court looked at the definition of the word "distribution" as well as the primary use of the street light assets. The parties stipulated that distribution meant "the delivery of electric energy to customers" and "the final utility step in the provision of electric service to customers." The Court found this definition to be consistent with a standard definition of distribution. 135 T.C. at 183. The Court also stated that the "distribution of electricity seems to us to be the process by which electricity (the commodity) gets to final consumers." Id. The Court found that street light assets could be disconnected from the distribution system without effecting electrical distribution to customers and they are distinct from distribution assets because they have a different purpose and function. On this last point, the Court found that distribution assets get final consumers electricity, service drops are the final part of the distribution of electricity to final consumers, and street light assets are not part of the service to get electricity to final consumers.

Section 306 of Division B of the Economic Stabilization Act of 2008, Pub. L. No. 110-343, 122 Stat. 3765 (2008), amended § 168 by adding §§ 168(e)(3)(D)(iii) and 168(i)(18). Both sections are effective for property placed in service after October 3, 2008.

Section 168(e)(3)(D)(iii) provides that the term "10-year property" includes any qualified smart electric meter.

Section 168(i)(18)(A) defines the term "qualified smart electric meter" as meaning any smart electric meter that: (i) is placed in service by a taxpayer who is a supplier of electric energy or a provider of electric energy services; and (ii) does not have a class life (determined without regard to §168(e)) of less than 10 years.

For purposes of § 168(i)(18)(A), § 168(i)(18)(B) defines the term "smart electric meter" as meaning any time-based meter and related communication equipment that is capable of being used by the taxpayer as part of a system that: (i) measures and records electricity usage data on a time-differentiated basis in at least 24 separate time segments per day; (ii) provides for the exchange of information between supplier or provider and the customer's electric meter in support of time-based rates or other forms of demand response; (iii) provides data to such supplier or provider so that the supplier or provider can provide energy usage information to customers electronically; and (iv) provides net metering.

Section 168(e)(3)(B)(iv) provides that any qualified technological equipment is 5-year property. Section 168(i)(2)(A) and (B)(i) define the term "qualified technological equipment" as meaning, in relevant part, any computer or any related peripheral equipment. Section 168(i)(2)(B)(ii) defines "computer" as meaning a programmable electronically activated device that: (I) is capable of accepting information, applying prescribed processes to the information, and supplying the results of these processes with or without human intervention; and (II) consists of a central processing unit containing extensive storage, logic, arithmetic, and control capabilities.

Section 168(i)(2)(B)(iii) defines "related peripheral equipment" as meaning any auxiliary machine (whether on-line or off-line) that is designed to be placed under the control of the central processing unit of a computer.

However, § 168(i)(2)(B)(iv) provides that the term "computer or peripheral equipment" shall not include, in relevant part, any equipment that is an integral part of other property that is not a computer.

The Tax Court in Broz v. Commissioner, 137 T.C. No. 3 (July 7, 2011), concluded that cell site equipment containing computerized parts, except for the switch, is not a computer under § 168(i)(2)(B)(ii). In reaching its conclusion, the Court determined that the key component of the base station and other cell site equipment was the radio. The Court found that the radio itself did not employ computer processing and did not contain a central processing unit containing extensive storage. The Court also found "compelling that even though the base station contained some of the same software as the switch, which is classified as a computer, the base station did not have the computer system or storage capacity to keep billing records." Further, the Court stated that the radio technology has functioned for many years without the use of computerized parts, suggesting that those parts are only ancillary.

In this case, the Director and Taxpayer agree that Meter 2 is a smart electric meter under § 168(i)(18)(B). A smart electric meter placed in service after October 3, 2008, is not a qualified smart electric meter under § 168(i)(18)(A) if the meter has a class life of less than 10 years. Thus, at issue in this technical advice memorandum is whether Meter 2 is classified in asset class 00.12 of Rev. Proc. 87-56 or is qualified technological equipment under § 168(i)(2).

Information systems

Meter 2, like Meter 1 and Taxpayer's electromechanical meters, is used in the distribution of electricity for sale to final consumers. Meter 2 is the device that allows electricity to flow from Taxpayer to its customers and that measures such electricity. Without these functions, Taxpayer would be unable to distribute and sell its electricity. Accordingly, Meter 2 (and Meter 1 and Taxpayer's electromechanical meters) are included in the activity category of asset class 49.14 of Rev. Proc. 87-56.

However, if an asset is included in both an asset category and an activity category, the asset is classified in the asset category unless it is specifically excluded from the asset category or specifically included in the activity category. See Norwest; Rev. Rul. 2003-81, 2003-2 C.B. 126. Accordingly, if Meter 2 also is included in the asset category of asset class 00.12 of Rev. Proc. 87-56, then Meter 2 is classified in asset class 00.12.

An asset is included in asset class 00.12 if the asset (i) is a computer or peripheral equipment and (ii) is used in administering normal business transactions and the maintenance of business records, their retrieval and analysis.

We first consider whether Meter 2 is used in administering normal business transactions and the maintenance of business records, their retrieval and analysis. During the year at issue, Meter 2 recorded the sale of electricity (the product) to Taxpayer's customers, stored this information for J days, and sent the information automatically to Taxpayer's data gathering system that leads to Taxpayer's customer care and billing central database. Meter 2 also protects Taxpayer from the loss of revenue generated by the sale of electricity. Meter 2 is tamper-resistant thereby preventing some common methods of electricity theft. Based on these uses of Meter 2 during the year at issue, we conclude that Meter 2 is used in administering normal business transactions and the maintenance of business records, their retrieval and analysis during the year at issue.

Next, we consider whether Meter 2 is a computer or peripheral equipment as defined in asset class 00.12 of Rev. Proc. 87-56.

Meter 2 is a computer as defined in asset class 00.12 of Rev. Proc. 87-56. First, it is a programmable electronically activated device. Taxpayer can program Meter 2 remotely through the wireless connectivity and internet protocols. Taxpayer's credit collection and billing department can program the disconnect switch contained in Meter 2 to interrupt, initiate, or restore electric service. The disconnect switch also can be programmed by the AMI communication module to perform a power-limiting function (i.e., shutting off electric service temporarily if the power usage through the meter exceeds a certain amperage). Meter 2 also can be programmed to detect energy tampering or service quality issues and to notify the central billing system when these events occur. Furthermore, Taxpayer can use the remote programming feature to enhance performance and features of Meter 2 (e.g., enhancing the security of Meter 2 and upgrading software programs).

Second, Meter 2 is capable of accepting information, applying prescribed processes to the information, and supplying the results of these processes with or without human intervention. For example, when customer-source power is supplied to the electric grid, Meter 2 does not immediately perform net metering. Instead, Meter 2 is capable of providing bi-directional metering. In this case, Meter 2 separately measures Taxpayer-supplied power and customer-supplied power, and then subtracts any customer-supplied power from Taxpayer-supplied power thereby converting the bi-directional metering data to net metering data. The bi-directional metering data also includes detailed time-of-day data that will allow TOU pricing. Meter 2 also has the capability to multiply electricity usage by the tariff rate to calculate the customer's bill, which is now done on Taxpayer's central office mainframe computers, and through the HAN module has the capability to send this information to display monitors at the customers' locations for viewing. While these functions were not used by Taxpayer during the year at issue, the plain language of asset class 00.12 focuses on the device's capability rather than the device's actual use during the year. Meter 2 also is capable of sending, and was used during the year at issue to send, usage data through Meter 2's LAN and the associated equipment to the Taxpayer's centralized database, where the data is further processed, checked, and translated.

Finally, Meter 2 contains a central processing unit with extensive storage, logic, arithmetic, and control capabilities. In evaluating this requirement, the Director and Taxpayer had differing views. Taxpayer argues that this determination should be based on what was considered extensive storage in 1984 when the definition of computer in the predecessor of § 168(i)(2)(B) (i.e., former § 168(j)(5)(D)) was enacted. The Director argues that the determination should be based on what is considered extensive storage currently. Given the ever-changing and increasing processing and storage capacities of computers, we do not agree with either position. Using Taxpayer's position will render the term "extensive" meaningless in asset class 00.12. Using the Director's position could potentially cause a device that was considered to have extensive storage, logic, arithmetic, and control capabilities in its placed-in-service year not to have such storage, logic, arithmetic, and control capabilities in a subsequent year during its recovery period. Instead, we believe that the determination should be based on what is considered to be extensive storage, logic, arithmetic, and control capabilities in the placed-in-service year of the device that are needed for the device to perform its actual and potential functions.

Based on the information provided to us to date, we believe that Meter 2 has a central processing unit containing extensive storage, logic, arithmetic, and control capabilities that enables Meter 2 to perform its functions actually used during the year at issue and its potential functions. While Meter 2's processing and storage capacity is comparable to early desktop computers, we believe that Meter 2's processing and storage capacity is sufficiently extensive to perform its actual and potential functions.

The exceptions in asset class 00.12 of Rev. Proc. 87-56 do not apply to Meter 2. Specifically, Meter 2 is not used primarily for process or production control, switching, channeling, and automating distributive trades and services such as point of sale computer systems. While the disconnect switch of Meter 2 can be programmed by the AMI communication module to perform a power-limiting function (i.e., shutting off electric service temporarily if the power usage through the meter exceeds a certain amperage) and Meter 2 can be programmed to detect energy tampering or service quality issues (e.g., pinpoint power outages), these process or production control uses are not the primary uses of Meter 2.

Arguably, Meter 2 is similar to a point of sale computer system. For insight into this question, it is necessary to examine the modifications made by Rev. Proc. 80-15, 1980-1 C.B. 618, to the asset classes in Rev. Proc. 77-10, 1977-1 C.B. 548.

Rev. Proc. 80-15 added the following new asset classes to Rev. Proc. 77-10: 57.0, Distributive Trades and Services, and 57.1, Distributive Trades and Services-Billboard, Service Station Buildings and Petroleum Marketing Land Improvements. These new asset classes include the assets that were included in asset classes 13.4, 50.0, 50.1, 70.2, and 70.21 of Rev. Proc. 77-10, which were deleted by Rev. Proc. 80-15. Rev. Proc. 80-15 also clarified asset class 00.12 of Rev. Proc. 77-10 by providing that asset class 00.12 does not include computers used primarily for automating distributive trades and services such as point of sale computer systems. Rev. Proc. 80-15 was effective for assets placed in service in taxable years ending on or after April 28, 1980. For taxable years ending prior to April 28, 1980, Rev. Proc. 80-15 provided that distributive trades and services automated equipment such as point of sale computer systems are properly classified in asset class 00.12, 50.0, or 70.2, depending upon which class was selected by the taxpayer on its original return.

Our review of the modifications made by Rev. Proc. 80-15 indicate that the addition of the new asset classes for distributive trades and services and the new exception to asset class 00.12 for computers used primarily for automating distributive trades and services such as point of sale computer systems are linked together. Accordingly, the exception to asset class 00.12 of Rev. Proc. 87-56 for computers used primarily for automating distributive trades and services such as point of sale computer systems is limited to business activities described in the asset classes for distributive trades and services (asset classes 57.0 and 57.1 of Rev. Proc. 87-56).

Based on Taxpayer's use of Meter 2, the plain language of asset class 00.12 of Rev. Proc. 87-56, and our conclusion that Meter 2 has a central processing unit containing extensive storage, logic, arithmetic, and control capabilities that enables Meter 2 to perform its functions actually used during the year at issue and its potential functions, Taxpayer's Meter 2 is an information system included in asset class 00.12 of Rev. Proc. 87-56.

We also conclude that the associated equipment is peripheral equipment as defined in asset class 00.12 of Rev. Proc. 87-56. The associated equipment is designed to be placed under the control of the central processing unit of Taxpayer's centralized computer system.

In this case, Meter 2 and the associated equipment serve a dual purpose. They are included in asset class 49.14 of Rev. Proc. 87-56, an activity category, and asset class 00.12 of Rev. Proc. 87-56, an asset category. An asset that is included in both an asset category and an activity category is classified in the asset category unless it is specifically excluded from the asset category or specifically included in the activity category. See Norwest; Rev. Rul. 2003-81. Because Meter 2 and the associated equipment are included in both asset class 00.12 and asset class 49.14, and not specifically excluded from asset class 00.12 or specifically included in asset class 49.14, Meter 2 and the associated equipment are classified in asset class 00.12. [1]

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[1] Meter 1 and Taxpayer's electromechanical meters are not included in asset class 00.12 of Rev. Proc. 87-56. The Director and Taxpayer agree that Meter 1 is not a computer. Based on the information provided to date, we believe

The Director makes several arguments in support of its position that Meter 2 is not included in asset class 00.12 of Rev. Proc. 87-56. First, the Director argues that based on the heading for the "00" asset classes of Rev. Proc. 87-56, Specific Depreciable Assets Used In All Business Activities, Except As Noted, the asset must be of a type used in all business activities to be included in an asset class with a "00" prefix; but Meter 2 can only be used in one specific type of activity, i.e., the sale of electricity by an electric company. We disagree. Under the heading "Specific Depreciable Assets Used in All Business Activities, Except as Noted," there are 14 asset classes with a "00" prefix and one of them is titled "Information Systems." For the reasons previously stated, we conclude that Meter 2 is an information system. Further, the asset classes with a "00" prefix prescribe class lives for specific depreciable assets, such as information systems, regardless of the business activity in which they are used.

Second, the Director argues that Meter 2 is not an information system because Taxpayer primarily uses this meter to distribute and measure electricity for sale. We agree that Taxpayer uses Meter 2 in this activity. However, as previously discussed, we conclude that Meter 2 is dual-use property that also is used by Taxpayer as an information system. In such a case, the asset category of asset class 00.12 of Rev. Proc. 87-56 prevails over the activity category of asset class 49.14 of Rev. Proc. 87-56. See Norwest; Rev. Rul. 2003-81 (bookcase primarily used in connection with the production of electricity for sale is classified in asset class 00.11 of Rev. Proc. 87-56 even though bookcase also is included in asset class 49.13 of Rev. Proc. 87-56).

The Director also argues that the exception in asset class 00.12 for equipment that is an integral part of other capital equipment that is included in other classes of economic activity should be applied broadly rather than applied only to the listed items. Asset class 00.12 does not include equipment that is an integral part of other capital equipment that is included in other classes of economic activity, ***i.e.***, computers used primarily for process or production control, switching, channeling, and automating distributive trades and services such as point of sale computer systems (emphasis added). If the listed items were meant to be examples, then "e.g." instead of "i.e." should have been used. Accordingly, the plain language of asset class 00.12 does not support a broader application.

Finally, the Director argues that Meter 2 is not an information system because it is not used by Taxpayer in administering normal business transactions and the maintenance of business records, their retrieval and analysis. For the reasons previously stated, we do not agree with this argument.

Qualified technological equipment

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that Meter 1 is not peripheral equipment. Further, Taxpayer's electromechanical meters clearly are not computers or peripheral equipment.

In light of our conclusion that Meter 2 and the associated equipment have a class life of less than 10 years because these assets are properly includible in asset class 00.12 of Rev. Proc. 87-56, we will not address whether Meter 2 and the associated equipment is qualified technological equipment under § 168(i)(2)(B). We note, however, that the definition of computer or peripheral equipment in § 168(i)(2)(B) is not the same as the definition of such terms in asset class 00.12 of Rev. Proc. 87-56. Specifically, the exception in § 168(i)(2)(B)(iv)(I) is broader than the exception in the last paragraph of asset class 00.12 of Rev. Proc. 87-56.

CAVEAT:

Temporary or final regulations pertaining to one or more of the issues addressed in this memorandum have not yet been adopted. Therefore, this memorandum will be modified or revoked by the adoption of temporary or final regulations to the extent the regulations are inconsistent with any conclusions in the memorandum. See section 13.03 of Rev. Proc. 2011-2, 2011-1 I.R.B. 90, 106 (or any successor). However, a technical advice memorandum that modifies or revokes a letter ruling or another technical advice memorandum generally is not applied retroactively if the taxpayer can demonstrate that the criteria in section 13.02 of Rev. Proc. 2011-2 are satisfied.

A copy of this technical advice memorandum is to be given to the taxpayer. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

EXHIBIT 3

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	Case No. 17-1263-EL-SSO
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	Case No. 17-1264-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Defer Vegetation Management Costs.	)	Case No. 17-1265-EL-AAM

DIRECT TESTIMONY OF

DONALD L. SCHNEIDER, JR.

ON BEHALF OF

DUKE ENERGY OHIO, INC.

June 1, 2017

TABLE OF CONTENTS

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as General Manager, Advanced Metering Infrastructure (AMI) Program Management. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville in 1986. After graduation, I was employed by Duke Energy Indiana, Inc., (then known as Public Service Indiana) as an electrical engineer. Throughout my career, I have held various positions of increasing responsibility in the areas of engineering and operations, including distribution planning, distribution design, field operations, and capital budgets. Prior to my current role, I was General Manager, Midwest Premises Services, responsible for managing all of Duke Energy's Midwest Premises Services and Meter Reading departments. I was promoted to my current position in 2008.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A. Yes. I have been registered as a professional engineer with the State Board of Registration for Professional Engineers in the state of Indiana since 1995.

Q. PLEASE DESCRIBE YOUR DUTIES AS GENERAL MANAGER, AMI PROGRAM MANAGEMENT.

A. As General Manager, AMI Program Management, my primary responsibility is managing the project execution of AMI-related projects and AMI systems operations for all Duke Energy jurisdictions. Prior to the merger between Duke Energy and Progress Energy, I was responsible for managing the project execution for both AMI and Distribution Automation (DA) deployments for all legacy Duke Energy jurisdictions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes. I have submitted pre-filed testimony and have testified before the Public Utilities Commission of Ohio (Commission).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. I will begin by providing a background on Duke Energy Ohio's AMI. Then I will describe the current state of the Company's AMI environment and some challenges to that environment and explain how the Company plans to address those challenges. Finally, I will discuss and quantify the benefits and costs associated with the Company's AMI proposal.

II. BACKGROUND ON DUKE ENERGY OHIO'S CURRENT AMI ENVIRONMENT

Q. WHAT IS AMI?

A. AMI involves a two-way communication network between the utility and its meters that is used to provide operational efficiencies and to enable customer services not possible with metering programs involving walk-by or one-way communications network (drive-by) readings.

Q. DESCRIBE THE CURRENT AMI ENVIRONMENT FOR DUKE ENERGY OHIO.

A. Today, the Company has two AMI metering environments, which I will describe as the node and mesh environments. The node environment is composed of Echelon electric meters, Badger gas communication modules, and communication nodes that were originally manufactured by Ambient, which has since been acquired by Ericsson. The mesh environment is composed of Itron electric meters, Itron gas communications modules, Itron range extenders, and Cisco Connected Grid Routers (CGRs).

Q. HOW DO COMMUNICATIONS WORK IN THE AMI NODE ENVIRONMENT?

A. Echelon electric meters communicate with nodes via two-way, low-voltage power-line carrier technology, and Badger gas communication modules communicate with nodes via one-way wireless radiofrequency signals. Each node is equipped with a cellular modem that allows for data and signals to be sent to and received from the node environment. The devices within the node environment are managed by head-end control systems. The Echelon Networked Energy Services (Echelon NES) head-end system manages Echelon AMI meters, the Badger Read Center manages the gas communication modules, and the Ambient Network Management System (Ambient NMS) manages the communication nodes.

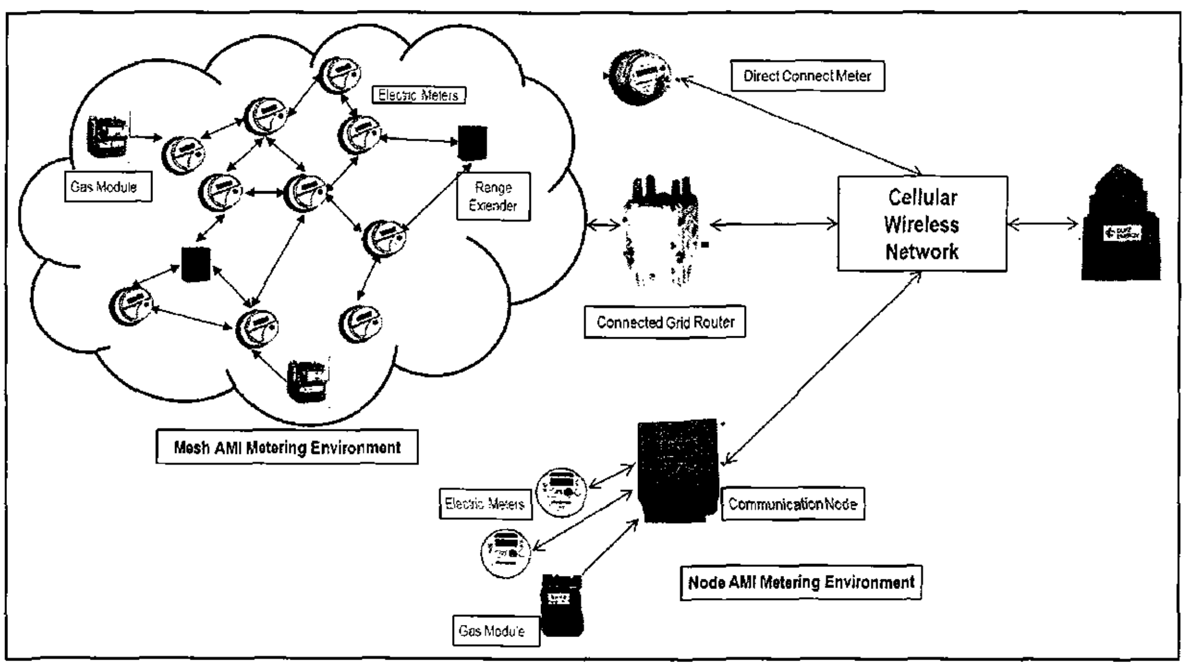
Q. HOW DO COMMUNICATIONS WORK IN THE AMI MESH ENVIRONMENT?

A. The mesh environment is so described because Itron electric meters communicate with one another and CGRs using wireless radiofrequency signals with IPv6 communication protocol, effectively forming a meshed communication network across a geographic area. Itron gas communication modules communicate with Itron electric AMI meters using a separate wireless radiofrequency signal that uses a communication protocol known as ZigBee and that data is then carried over the mesh network to CGRs. Each CGR is equipped with a cellular modem that allows for data and signals to be sent to and received from the mesh environment. Itron range extenders are used in the mesh environment to help extend the wireless radiofrequency signal when necessary. The Itron OpenWay head-end system manages the Itron AMI meters and the Cisco Network Management System (CGNMS) manages the CGRs.

Figure 1 below illustrates Duke Energy Ohio's overall AMI network architecture. The mesh environment is depicted in the top left corner of the image. It shows gas modules communicating with electric meters and the electric meters communicating with one another and the CGR wirelessly. It then shows how the

CGR communicates through the cellular wireless network. The node environment is portrayed at the bottom of the image. It shows electric meters and gas modules communicating directly to a communication node, which also then communicates through the cellular wireless network. Finally, at the top of Figure 1 there is a depiction of an Itron Direct Connect electric AMI meter, which communicates directly over the cellular wireless network using a built-in cellular radio. The Direct Connect meters are used as an alternative for situations in which an Itron mesh electric meter at a specific premises cannot connect reliably with other mesh network meters in that area and it is cost prohibitive to extend the mesh utilizing Itron range extenders.

Figure 1:



Q. WHAT IS THE MAJOR DIFFERENCE BETWEEN THE AMI NODE AND MESH METERING ENVIRONMENTS?

A. Since the node environment utilizes low-voltage power-line carrier technology that requires installation of communication nodes at power transformers associated with the downstream electric meters, individual communication nodes only support about five electric AMI meters on average. In comparison, the mesh environment is typically designed so that 500 to 1,000 meters can communicate with a single CGR.

Q. WHAT CUSTOMER CLASSES ARE SERVED BY THE SEPARATE AMI ENVIRONMENTS?

A. The node environment serves most of Duke Energy Ohio's residential electric and residential combination gas and electric customers. The mesh environment serves most of the Company's commercial/industrial customer classes, as well as some residential customers. The mesh environment also serves some combination gas and electric customers in both the residential and commercial/industrial customer classes.

Q. WHY IS THERE A DIFFERENCE IN AMI ENVIRONMENTS BASED ON CUSTOMER TYPE?

A. Beginning in 2009, the Company installed the AMI node environment technology with electric meters manufactured by Echelon. Echelon began manufacturing AMI meters with the Form 2s Class 200 meter type, which is primarily used by residential customers. Echelon had planned to continue development of AMI electric meters for all other meter forms but the market never developed in North

America for this technology so they did not start manufacturing other meter forms. Therefore, the majority of Duke Energy Ohio's residential electric customers are served by an Echelon meter. After analyzing other AMI environments, the Company standardized on the Itron AMI mesh environment and installed electric AMI meters manufactured by Itron for most of its commercial/industrial electric customers and any additional customers who could not be served by an Echelon Form 2s Class 200 AMI meter. In some cases, such as when a customer requires demand readings, Duke Energy Ohio installed Itron AMI meters for residential electric customers as well.

Q. WHERE IS DUKE ENERGY OHIO'S AMI METER DATA STORED?

A. Duke Energy Ohio's AMI meter data is stored in two separate meter data management systems, which are responsible for processing and storing vast amounts of collected meter data. For the node environment, interval AMI customer energy usage data (CEUD) is stored in Oracle's first-generation meter data management system called the Energy Data Management System (EDMS). For the mesh environment, interval AMI CEUD is stored in Oracle's second-generation meter data management system, which Duke Energy Ohio calls MDM. Data in EDMS and MDM is used by Duke Energy Ohio's billing system known as the Customer Management System (CMS) for billing functions.

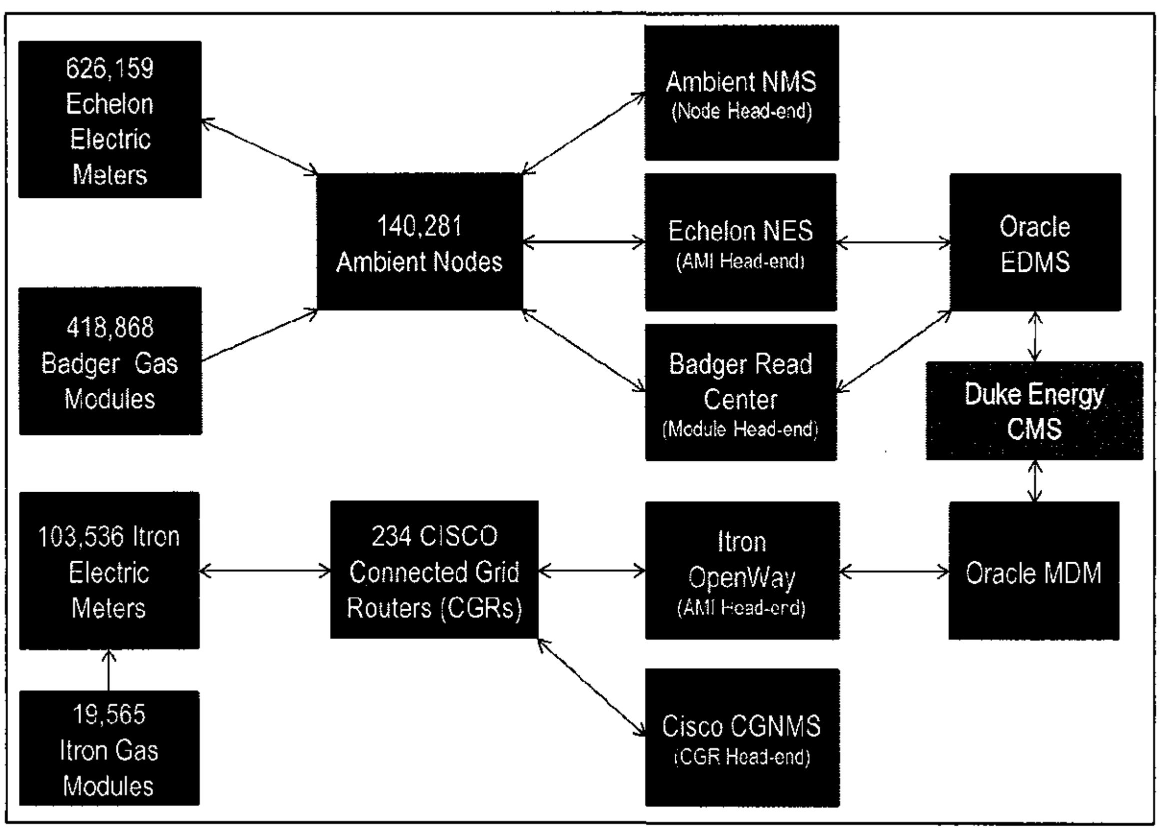
Q. DESCRIBE THE DIFFERENCES BETWEEN EDMS AND MDM WITH REGARD TO HOW THEY PROCESS INTERVAL AMI CEUD.

A. MDM provides scalable Validation, Estimation, & Editing (VEE) functionality for interval AMI CEUD. EDMS relies on the CMS to provide scalable VEE functionality for interval AMI CEUD. Interval AMI CEUD coming out of the MDM system is considered billing-quality interval AMI CEUD, while interval AMI CEUD that comes out of EDMS is not considered billing-quality interval AMI CEUD.

Q. WHAT IS THE CURRENT BREAKDOWN OF DEVICES DEPLOYED ACROSS DUKE ENERGY OHIO'S TWO AMI METERING ENVIRONMENTS?

A. Figure 2 provides a visual representation of this device breakdown as of January 31, 2017. It also displays the respective head-ends, network management systems, and meter data management systems for the two AMI metering environments.

Figure 2:



Using figures as of January 31, 2017, 626,159 Echelon electric meters and 418,868 Badger gas communication modules communicate directly with 140,281 communication nodes in the node environment. As of the same date, 103,536 Itron electric meters communicate with 234 CGRs and 19,565 Itron gas communication modules communicate through the Itron electric meters to the CGRs in the mesh environment.

Q. IS DUKE ENERGY OHIO FACING ANY ISSUES WITH ITS AMI METERING ENVIRONMENTS?

A. In Duke Energy Ohio's AMI node environment, Ericsson is no longer manufacturing communication nodes. Duke Energy Ohio's inventory of nodes is therefore depleting beyond the desired stocking level with each device failure. Additionally, communication nodes have been failing at a higher rate than expected.

Q. WHAT IS DUKE ENERGY OHIO DOING TO ADDRESS THIS ISSUE IN THE NEAR TERM?

A. Duke Energy Ohio has begun a business continuity effort for the years 2017-2018 to remove approximately 23,700 communication nodes currently deployed in the field, in order to restore inventory back to desired stocking levels. Removing these nodes – transitioning from the AMI node environment to the mesh environment – requires expanding the footprint of the Company's existing mesh environment; consequently, the Company will replace approximately 80,000 Echelon electric meters and 48,800 Badger gas communication modules with Itron electric meters and Itron gas communication modules. Upon completion of the effort, the AMI node environment will contain approximately 546,000 Echelon electric meters, 370,000 Badger gas communication modules, and 120,000 communication nodes remaining in the field.

Q. WHAT IS THE ESTIMATED TIMELINE TO ADDRESS THIS NODE ISSUE AS DESCRIBED ABOVE?

A. The Company began expanding the mesh environment footprint in early 2017. This business continuity work is expected to conclude by the end of 2018.

III. FUTURE STATE OF THE COMPANY'S AMI ENVIRONMENT

Q. PLEASE DESCRIBE HARDWARE UPGRADES REQUIRED FOR DUKE ENERGY OHIO'S AMI METERING ENVIRONMENTS IN THE COMING YEARS.

A. Verizon, the Company's primary cellular provider, has alerted the Company that their second generation (2G) and third generation (3G) cellular networks will be discontinued, or sunset, in 2022. Verizon originally planned to discontinue these networks earlier than 2022, but through Duke Energy's partnership with Verizon, it was agreed to extend the sunset to 2022. No further extension is expected. The 2G and 3G sunset will require Duke Energy Ohio to completely transition all of its communication devices – whether they are nodes or CGRs – to the Verizon 4G network prior to end of 2022. The 2G and 3G sunset applies to all users of the Verizon cellular network, including anyone using Verizon's personal cellular services.

Q. HOW DOES VERIZON'S DECISION TO DISCONTINUE SUPPORTING THE 2G AND 3G SYSTEMS AFFECT THE COMPANY'S AMI MESH ENVIRONMENT?

A. Cisco has already released a 4G CGR. Duke Energy Ohio will need to upgrade 233 of its current 234 CGRs to 4G communications technology before Verizon ends its support. Upgrading a CGR involves swapping out the 3G communication card for a 4G communication card and replacing the CGR's antennas.

Q. HOW DOES VERIZON'S DECISION TO DISCONTINUE SUPPORTING THE 2G AND 3G SYSTEMS AFFECT THE COMPANY'S AMI NODE ENVIRONMENT?

A. The loss of support for 2G and 3G is a significant long-term challenge for Duke Energy Ohio's node environment due to the sheer volume of communication nodes. As I mentioned previously, there are far more communication nodes installed since the ratio of meters to nodes is so much lower than the ratio of meters to CGRs. The Company would need to upgrade at least 140,000 nodes. Adding to the challenge, the communication nodes are no longer being manufactured, but the Company could work with the vendor to source a replacement 4G modem and antenna that could be retrofitted into the node. Upgrading a node to the 4G network is more complicated than the upgrade process for CGRs. The node design incorporates a cellular modem chip that is soldered onto the communication node's motherboard; so, it is a more delicate and labor-intensive process than what is required for CGRs, which incorporates a cellular modem card design.

Q. ARE THERE ANY OTHER LONG-TERM CHALLENGES IN SUPPORTING THE AMI NODE ENVIRONMENT?

A. Since the Company began its AMI deployment, Ambient has been purchased by Ericsson and Duke Energy Ohio remains the only customer utilizing the specific communication nodes that were manufactured by Ambient. While Echelon has had success in other countries, Duke Energy Ohio remains the only North American company utilizing the Echelon AMI nodal solution. The high failure rate of nodes, the lack of North American adoption, and the fact that the nodes are no longer manufactured are all factors that present risk to Duke Energy Ohio and its customers. Even if the Company were to upgrade all its communication nodes to the Verizon 4G network, the node failure issue would not be resolved. The nodes are already approaching the end of their expected 10-year useful life. The Company would need to continue removing nodes and switching customers to the mesh environment, just for business continuity beyond 2018. The Company has a support contract in place for node repair but, with the higher than expected failure rates, Ericsson is not able to keep up with the repairs.

Q. HOW DOES DUKE ENERGY OHIO PLAN TO ADDRESS THE LONG-TERM CHALLENGE WITH THE NODE ENVIRONMENT?

A. Rather than upgrading the communication nodes to 4G and perpetuating the support concerns the Company is already confronting in the near-term, the Company proposes to transition entirely from the AMI node environment to the AMI mesh environment (Ohio AMI Transition). The estimated total cost of the Ohio AMI Transition effort is approximately $143.4 million, most of which will be capital costs. The work would begin in 2019 and conclude by the end of 2022. Attachment DLS-1 shows the estimated costs of ownership/operation and a net present value (NPV) comparison of the Ohio AMI Transition effort versus retaining the node environment. I will discuss the benefits and costs of the Ohio AMI Transition in depth over the next two sections of testimony.

IV. BENEFITS OF THE PROPOSED AMI TRANSITION

Q. WHAT ARE THE OVERARCHING BENEFITS OF COMPLETELY TRANSITIONING FROM THE NODE TO THE MESH AMI METERING ENVIRONMENT?

A. The Ohio AMI Transition would allow Duke Energy Ohio to avoid approximately $91.2 million in total costs to upgrade its AMI node environment to 4G, as shown on Attachment DLS-1. Having all meters in the Itron AMI mesh environment would mean that the Company would have billing-quality interval AMI CEUD for all its electric customers with AMI meters because Itron meters necessarily feed data into MDM rather than EDMS.

Going forward, support for the mesh environment will be significantly less costly – in terms of both avoided costs and reduced costs – than the cost of continuing to support the node environment. Attachment DLS-1 shows that the 20-year NPV of costs associated with keeping the node environment in place is approximately $190.3 million, while the 20-year NPV of costs associated with the Ohio AMI Transition is approximately $134.7 million.

Additionally, the Ohio AMI Transition would position the Company to provide its customers with programs and services of importance to them, which I understand is consistent with the Commission's PowerForward initiative and its intention to consider ways in which to transform the electric distribution grid and enhance the customer experience.

Q. WHAT IS THE BENEFIT OF AVOIDING THE 4G UPGRADE COSTS FOR THE COMMUNICATION NODES?

A. Duke Energy Ohio would face significant costs to upgrade its communication nodes to 4G, an unavoidable upgrade if it continues using the AMI node environment. The Company estimates that it would cost approximately $91.2 million for the project, which would begin in 2019 and end in 2021. The Ohio AMI Transition will allow Duke Energy Ohio to avoid those costs by installing 4G CGRs and Itron AMI meters.

Q. WHAT IS THE BENEFIT OF NO LONGER SUPPORTING THE NODE ENVIRONMENT?

A. If Duke Energy Ohio does not receive necessary regulatory approval and has to continue with the node environment instead of undertaking the Ohio AMI Meter Transition, the Company estimates it would spend $1 million in 2019 just to develop a long-term solution to address the node failure issue. At that point, the business continuity effort will have concluded, but the node failure rate is expected to continue increasing.

Besides addressing the node failure issue, the future costs to support the node environment and its related systems would be avoided or reduced if the Company pursues the Ohio AMI Meter Transition. Duke Energy Ohio would spend less in annual on-going operation and maintenance (O&M) costs if it transitions the entire node environment to the mesh environment. That includes reduced costs for monthly cellular contracts and for managing communication node failures, as well as avoided costs for system upgrades and vendor maintenance.

V. COSTS OF THE PROPOSED AMI TRANSITION

Q. WHAT IS THE ESTIMATED COST AND TIMELINE FOR THE OHIO AMI TRANSITION?

A. Duke Energy Ohio estimates that the Ohio AMI Transition will cost approximately $143.4 million, most of which will be capital costs. Attachment DLS-1 shows a breakdown of project costs between electric, gas, communications, and software by capital and O&M. The deployment would begin in 2019 and conclude in 2022.

Q. WHAT PORTION OF THE TOTAL OHIO AMI METER TRANSITION COSTS IS FOR ELECTRIC SERVICE AND GAS SERVICE?

A. About $106.5 million of total costs for the Ohio AMI Transition are attributable to electric service. Just under $36.9 million of total costs are attributable to gas service.

Q. HOW DO THE COSTS OF THE BUSINESS CONTINUITY EFFORT AND OHIO AMI TRANSITION COMPARE TO THE BENEFITS OF AVOIDING THE NODE ENVIRONMENT COSTS?

A. As mentioned earlier, Attachment DLS-1 shows that the NPV of costs to maintain the node environment from 2019 through 2038 is $190.2 million versus $134.7

million to pursue the Ohio AMI Transition over the same time period. The 20-year NPV analysis was used in alignment with typical internal cost analyses.

Q. IS THE COMPANY PROPOSING TO RECOVER ANY OF THE COSTS OF THE OHIO AMI TRANSITION IN THESE PROCEEDINGS?

A. As discussed in the Direct Testimony of witness William Don Wathen Jr., capital expenditures associated with the Ohio AMI Transition would be recovered through Rider DCI, expanded to include distribution-related general, intangible, and common plant, as proposed in these proceedings. O&M costs would be recovered under the proposed PowerForward Rider, to the extent not otherwise recovered in base rates.

VI. CONCLUSION

Q. WAS ATTACHMENT DLS-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN ATTACHMENT DLS-1 TRUE AND ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Total (All Electric and Gas Costs)

Discount Rate (DEO before tax)	7.73%		NPV	TOTAL (2019-2038)
		Continue Node Environment		
	O&M	4G Communication Node Upgrade	78,694,632	91,162,500
		EDMS to MDM Conversion	14,140,117	15,800,000
		Long-term Communication Node Solution	928,247	1,000,000
		NES Headend Upgrades	5,123,981	10,589,310
		Monthly Cellular Cost	15,487,719	33,216,510
		Communication Device Failures	49,779,269	118,383,860
		Vendor Maintenance	26,129,276	56,039,456
			190,283,240	326,191,636
		Transition to Mesh Environment		
	Capital	Ohio AMI Transition	123,299,685	143,398,848
	O&M	Monthly Cellular Cost	6,418,755	14,237,970
		Communication Device Failures	372,557	930,746
		Vendor Maintenance	4,615,356	10,644,198
			134,706,353	169,211,762

Electric Costs Only

Discount Rate (DEO before tax)	7.73%		NPV	TOTAL (2019-2038)
		Continue Node Environment		
	O&M	4G Communication Node Upgrade	69,487,360	80,496,488
		EDMS to MDM Conversion	8,625,471	9,638,000
		Long-term Communication Node Solution	566,230	610,000
		NES Headend Upgrades	5,123,981	10,589,310
		Monthly Cellular Cost	9,447,509	20,262,071
		Communication Device Failures	43,955,094	104,532,948
		Vendor Maintenance	19,073,436	40,906,796
			156,279,082	267,035,613
		Transition to Mesh Environment		
	Capital	Ohio AMI Transition	91,584,689	106,505,554
				-
	O&M	Monthly Cellular Cost	3,915,440	8,685,162
		Communication Device Failures	328,968	821,849
		Vendor Maintenance	3,528,090	8,141,157
			99,357,188	124,153,722

Gas Costs Only

Discount Rate (DEO before tax)	7.73%		NPV	TOTAL (2019-2038)
		Continue Node Environment		
	O&M	4G Communication Node Upgrade	9,207,272	10,666,013
		EDMS to MDM Conversion	5,514,645	6,162,000
		Long-term Communication Node Solution	362,016	390,000
		NES Headend Upgrades	-	-
		Monthly Cellular Cost	6,040,211	12,954,439
		Communication Device Failures	5,824,174	13,850,911
		Vendor Maintenance	7,055,839	15,132,659
			34,004,158	59,156,021
		Transition to Mesh Environment		
	Capital	Ohio AMI Transition	31,714,995	36,893,294
				-
	O&M	Monthly Cellular Cost	2,503,314	5,552,808
		Communication Device Failures	43,589	108,896
		Vendor Maintenance	1,087,267	2,503,044
			35,349,165	45,058,042