BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation for Approval of Its Smart Meter Technology Procurement and Installation Plan	: : :	Docket Nos. P-2014-__________ M-2009-2123945

PETITION OF
PPL ELECTRIC UTILITIES CORPORATION

I. INTRODUCTION

Pursuant to 52 Pa. Code § 5.41, PPL Electric Utilities Corporation ("PPL Electric" or the "Company") hereby files the above-captioned Petition with the Pennsylvania Public Utility Commission ("Commission"). Herein, PPL Electric requests expedited Commission approval to implement a Smart Meter Plan ("SMP") that will fully comply with all of the requirements of Act 129 of 2008, P.L. 1592 ("Act 129") and the Commission's Smart Meter *Implementation Order*.[1] PPL Electric proposes to begin implementing the technology necessary for smart meters in 2015 with full deployment of smart meters beginning in the middle of 2017 through the end of 2019. In order to accommodate this accelerated deployment schedule, PPL Electric requests Commission approval of its SMP by December 31, 2014.

PPL Electric submitted its Initial Smart Meter Technology Procurement and Installation Plan ("Initial SMP") with the Commission on August 14, 2009. Therein, the Company explained that its existing metering system met the Act 129 smart meter requirements. The Company therefore proposed to use the 30-month Grace Period provided by the Commission in its Smart Meter *Implementation Order* to conduct a series of pilot programs and technology

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[1] *Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, Order entered June 24, 2009 ("*Implementation Order*").

evaluations to extend and enhance the capabilities of the Company's existing advanced meter system.

On June 24, 2010, the Commission entered an Order regarding the Company's Initial SMP.[2] In the *2010 Smart Meter Order*, the Commission stated that PPL Electric's existing metering system did not fully meet Act 129's requirements. In particular, the Commission stated that PPL Electric should continue to identify, test, develop and implement cost effective ways to provide metered usage data directly to customers. *2010 Smart Meter Order*, p. 22. In addition, the Commission stated that PPL Electric should use its grace period pilot programs to develop a plan to be filed with the Commission to fully comply with Act 129. *2010 Smart Meter Order*, p. 24.

On May 24, 2012, PPL Electric filed a request to extend its grace period from December 2012 to December 2014 to allow additional time for the Company to file a smart meter plan that fully complies with the Act 129 requirements. On August 2, 2012, the Commission issued an Order authorizing the Company to file a SMP on or before June 30, 2014.[3]

PPL Electric hereby files its SMP pursuant to the Commission's *2012 Smart Meter Order*. Herein, PPL Electric proposes to replace its existing power line carrier ("PLC") metering system with a Radio Frequency ("RF") Mesh metering system that will fully meet the requirements of Act 129 and the Commission's *Implementation Order*. The primary reasons why PPL Electric is proposing to replace its PLC system with an RF Mesh AMI system are explained below.

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[2] *Petition of PPL Electric Utilities Corporation for Approval of Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123945, Order entered June 24, 2010 ("*2010 Smart Meter Order*").

[3] *Petition of PPL Electric Utilities Corporation for Approval to Modify its Smart Meter Technology Procurement and Installation Plan and to Extend its Grace Period*, Docket Nos. P-2012-2303075, M-2009-2123945, Order entered August 2, 2012 ("*2012 Smart Meter Order*").

Over the past several years, the Company has performed a series of pilot programs, in part, to determine if its existing metering system could be upgraded to fully meet the requirements of Act 129 and the Commission's *Implementation Order*. The primary deficiency of PPL Electric's existing PLC system is its inability to provide customers with direct access to price and usage information. Other EDCs in Pennsylvania are proposing to provide this functionality to customers through Home Area Network ("HAN") capability. PPL Electric has conducted a HAN pilot program. However, the Company was unable to effectively offer this functionality to pilot program customers, and the Company is not aware of a PLC solution for its system that would effectively meet this requirement. In addition, the Company conducted an analysis of the communications capability of its existing PLC system. This analysis revealed bandwidth constraints that would impact the Company's ability to provide 15 minute interval data for a large number of meters from certain substations while still maintaining the Company's ability to meet its internal requirements for reading meters.

In addition, approximately 1.2 million or 86% of the Company's existing meters are prior generation electro-mechanical meters. All of these meters would need to be replaced with new solid state electronic meters in order to provide remote disconnect/reconnect functionality, meet industry on-board meter storage standards, have the ability to be upgraded with technology advancements, have the ability to be remotely programmed, and support net metering. Even if these electro-mechanical meters were replaced with new solid state electronic meters, the electronic meters and the PLC system would not be able to effectively provide HAN technology to customers.

Moreover, the Company's current metering infrastructure, including meter hardware and communication equipment, is approaching the end of its life. For 2013, the Company's meter failure rate was approximately four times the industry standard. Due to the age of the Company's existing system, a substantial portion of that system would have to be replaced within the next several years.

Further, PLC technology is not widely used across the country. Very few investor owned utilities currently utilize PLC technology. RF technology is the dominant technology used by utilities to provide smart meter technology to customers and is the technology proposed by all major EDCs in Pennsylvania.

The Company's SMP includes a description of: the Technology Assessment conducted by the Company; the Company's proposed Vendor Selection process; its Implementation Plan; the Company's Cybersecurity and Data Privacy Plans; Organizational Impacts; Program Risks; Program Benefits; Program Costs; the Company's Communication Strategy; and the Company's Cost Recovery proposal. A copy of the Company's SMP (PPL Electric Exhibit No. 1) and supporting testimony is provided with this Petition. For the reasons explained in this Petition, in the SMP and in the supporting testimony, the Company's SMP is in the public interest and should be approved.

II. BACKGROUND

1. PPL Electric provides electric distribution, transmission and provider of last resort services to approximately 1.4 million customers in a certificated service territory that spans approximately 10,000 square miles in all or portions of 29 counties in eastern and central Pennsylvania. PPL Electric is a "public utility" and an "electric distribution company" ("EDC") as those terms are defined under the Public Utility Code, 66 Pa. C.S. §§ 102 and 2803.

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3. Act 129 became effective on November 14, 2008. Act 129 required EDCs to file Smart Meter Plans within nine months after the effective date of the Act. Act 129 provides, among other things, that each Pennsylvania EDC with at least 100,000 customers is required to provide smart meter technology to customers in accordance with a schedule not to exceed 15 years. Act 129 defines smart meter technology as follows:

> (g) Definition. – As used in this section, the term "smart meter technology" means technology, including metering technology and network communications technology capable of bidirectional communication, that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to

> enable the technology. The technology shall provide customers with direct access to and use of price and consumption information. The technology shall also:
>
> (1) Directly provide customers with information on their hourly consumption.
>
> (2) Enable time-of-use rates and real-time price programs.
>
> (3) Effectively support the automatic control of the customer's electricity consumption by one or more of the following as selected by the customer:
>
> (i) the customer;
>
> (ii) the customer's utility; or
>
> (iii) a third party engaged by the customer or the customer's utility.

66 Pa. C.S. § 2807(g).

4. The Commission adopted its *Implementation Order* on June 18, 2009, outlining its guidance for an EDC's Smart Meter Procurement and Installation Programs pursuant to Act 129. The *Implementation Order* established the standards that each plan must meet and provided guidance on the procedures to be followed for submittal, review and approval of each smart meter plan. Additionally, in the *Implementation Order*, the Commission granted a 30-month grace period following plan approval for EDCs to assess needs, select technology, secure vendors, train personnel, install and test support equipment and establish a detailed meter deployment schedule. *Implementation Order,* p. 9.

5. On August 14, 2009, PPL Electric filed its Initial SMP with the Commission. In its Initial SMP, the Company explained that it had deployed an automatic meter reading system beginning in 2002. Beginning in 2005, PPL Electric expanded the capabilities of its automated meter reading system by installing a Meter Data Management System ("MDMS"). PPL Electric believed that its existing smart meter system was able to support all of the capabilities set forth in

the Commission's *Implementation Order*. In addition, PPL Electric explained that it proposed to use the 30-month grace period to conduct a series of pilot programs and technology evaluations designed to extend the capabilities of its current system.

6. On June 24, 2010, the Commission approved PPL Electric's Initial SMP with several modifications. Of note, the Commission held that PPL Electric's existing metering system did not provide customers with direct access to customer usage data. The Commission directed PPL Electric to use the grace period to continue to identify, test, develop and implement cost effective means to directly provide metered usage data from the meter to customers so as to effectively support the automatic control of electricity consumption. In addition, the Commission directed PPL Electric to develop a SMP, to be filed with the Commission, to fully comply with Act 129.

7. On May 4, 2012, PPL Electric filed a request to extend its grace period from December 2012 to December 2014 to allow the Company more time to evaluate whether its existing PLC system could meet the Act 129 smart meter requirements.

8. On August 2, 2012, the Commission issued its *2012 Smart Meter Order* authorizing the Company to file a SMP on or before June 30, 2014. PPL Electric hereby files its SMP pursuant to the Commission's *2012 Smart Meter Order*.

III. DISCUSSION

A. PPL ELECTRIC'S EXISTING METERING SYSTEM MUST BE REPLACED.

9. PPL Electric's existing metering system does not fully meet the requirements of Act 129 and the Commission's *Implementation Order*. In its *2010 Smart Meter Order*, the Commission stated as follows: "Since PPL's existing system does not fully meet all Act 129

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requirements, it should use the Grace Period Pilot programs to fully develop a Plan, to be filed with the Commission, to fully comply with Act 129." *2010 Smart Meter Order*, p. 24.

10. The primary deficiency in PPL Electric's existing metering system is the inability to provide customers with direct access to price and use information through a HAN. See *2010 Smart Meter Order*, p. 22.

11. PPL Electric has conducted a HAN pilot program to determine whether its existing system could effectively provide customers direct access to price and use information. This HAN pilot program did not demonstrate the ability to reasonably provide customers with direct access to price and use information. In addition, PPL Electric is not aware of any existing solution for its PLC system that could effectively provide this functionality to customers. Therefore, PPL Electric's existing PLC system does not adequately meet the direct access requirements of Act 129.

12. PPL Electric's existing PLC system also has other limitations that would inhibit the Company's ability to fully meet the spirit and intent of Act 129. For example, bandwidth constraints on some of the Company's power lines and substations could limit the ability to provide 15 minute interval data in the future. In addition, the Company's current system must be pinged in order to provide two-way communication, whereas an RF Mesh system can communicate proactively to provide last-gasp communications. Moreover, an RF Mesh system is more effectively able to provide voltage information, temperature information and other near real-time information and alarms.

13. In order to meet industry on-board meter storage standards, have the ability to be upgraded with technology advancements, have the ability to be remotely programmed or support net metering, approximately 1.2 million or 86% of the Company's existing meters would need to

be replaced with solid state electronic meters. In addition, only 30,000 of the Company's 1.4 million meters have remote connect/disconnect technology.

14. Moreover, the Company has been experiencing increasingly higher meter failure rates over the past several years. For calendar year 2013, the Company's meters failed at a rate of approximately four times the industry standard. Furthermore, the Company recognizes that AMI communications hardware installed during the initial AMI deployment is the same age as the meter population and is also approaching the end of its useful life.

15. For these reasons and as explained in more detail in the Company's SMP, the Company's existing meter system must be replaced.

B. TECHNOLOGY ASSESSMENT

16. In 2013, PPL Electric conducted an evaluation of next generation AMI technologies. The objective of the evaluation was to gain an understanding of new AMI technologies that currently exist in the marketplace.

17. This evaluation focused on the primary AMI technology types that are predominant in the United States and around the world, including PLC technology, Point to Multi-Point technology and RF Mesh technology.

18. During the evaluation, PPL Electric conducted a series of workshops with IBM consultants to discuss available solutions, the strengths and weaknesses of available technology types and compatibility with the Company's current AMI Information Technology ("IT") infrastructure. From these discussions, the Company generated a high level list of functional

requirements for metering technology, Head-End System[4] technology and software information technology.

19. The Company then conducted a Request for Information ("RFI") from interested vendors to obtain more information regarding potential marketplace solutions and estimated costs of those solutions. RFI responses were evaluated to determine compliance with Act 129 and the *Implementation Order* requirements, ability of the solution to meet the Company's smart meter goals, financial risk, commercial risk, ability of the solution to meet IT and network requirements and how broadly the proposed systems were used by other utilities.

20. Based upon this extensive evaluation, PPL Electric is proposing to replace its existing PLC system with an RF Mesh system. A PLC system has limited ability to fully meet all regulatory and business requirements. In addition, RF based systems are widely used across the United States and are being proposed by all EDCs in Pennsylvania. Additional reasons why PPL Electric chose an RF Mesh solution are provided in Section III(B) of the SMP.

21. The new smart meter system will require the replacement and/or installation of additional IT and related systems to provide smart meter technology to customers. These systems include a Head-End System which, as explained above, collects data from the meters and field devices and also can send out commands to the meters and field devices.

22. The Company also assessed whether it should upgrade its Meter Data Management System ("MDMS"). The MDMS provides for storage of data from smart meters, including interval meter reads, and processes raw meter data for billing purposes. The evaluation concluded that PPL Electric's existing MDMS is not capable of supporting all of the Act 129 functionalities without significant development, upgrading and customization. Based upon its

[4] The Head-End System collects data (interval reads, outage and restoration messages, voltage data and other data) from the meters and field devices and also sends out commands (connect/disconnect, firmware upgrades, etc.) to the meters and field devices.

evaluation, the Company is proposing to install a new MDMS system to better address the Act 129 requirements and the Company's business needs. Additional details regarding the Company's MDMS evaluation are provided in Section III(C) of the SMP.

23. In conjunction with the AMI and MDMS evaluations, the Company also evaluated its Energy Analyzer Customer Portal System. The Portal System provides customers with access to view and analyze their energy usage. PPL Electric's current Energy Analyzer is dated and is limited in providing customers additional tools and information that may allow them to better manage and conserve energy use.

24. As a result of its evaluation, the Company is proposing to upgrade its existing Energy Analyzer System to better provide customers with the benefit of smart meter technology. In addition to existing capabilities such as providing customers access to historical interval usage data and energy management features, the Company will look for features to enhance customer service by enabling more customer self-service and energy conservation capabilities. Please see Section III(D) of the SMP for additional details.

25. In addition to evaluating the systems described above, PPL Electric also assessed a Network Operating Center ("NOC"). The NOC manages the operations of the meters and network equipment. It facilitates the identification and resolution of system operational issues in near real time. This capability will be used for deployment and ongoing operations.

26. The Company is also proposing to upgrade its Meter Asset Management ("MAM") System. A MAM system tracks the meter and field devices, capturing testing results, installation, maintenance and retirement information. An upgrade to the MAM system would also allow for advanced tracking of smart meter hardware (meters and network equipment),

software and firmware versions. Therefore, the Company proposes to upgrade its MAM system as part of its SMP.

C. SMART METER CAPABILITIES

27. In the Commission's *Implementation Order*, the Commission identified six smart meter capabilities that are required by Act 129. *Implementation Order*, pp. 29-30. In addition, the Commission listed nine additional capabilities that EDCs were to consider. *Implementation Order*, p. 30. Further, in December 2012, the Commission entered an order establishing additional requirements for smart meter plans. *Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, Final Order entered December 6, 2012. As explained below, the Company's proposed RF Mesh system will have the capability to meet all of these requirements.

1. Required Capabilities Under Act 129

a. Bidirectional Data Communication

28. The RF Mesh system will better enable the Company to meet the statutory bidirectional data communication requirements than the Company's existing PLC system. PPL Electric's current PLC system only allows for polling meters to obtain information and does not support proactive communication from the meters in real time. The RF Mesh system will allow near real time communications to be sent by a meter to the Head-End system and will enable last-gasp technology in the event of a loss of power to the meter. Last gasp technology allows the meters to send a signal to the Head-End System when service is disrupted.

b. Recording Usage Data On At Least An Hourly Basis Once Per Day

29. The RF Mesh solution will enhance the Company's ability to record usage data. The current PLC system posts hourly data to the customer web platform approximately 31-33 hours after each day. An RF solution and MDMS replacement will enable the Company to

record data on any scheduled interval. Data can be collected every eight hours (or more frequently if necessary) and then processed. An upgraded MDM will also allow for continuous data processing, which should allow data to be presented to customers faster than the current system allows.

c. Providing Customers With Direct Access To And Use Of Price And Consumption Information

30. PPL Electric's existing PLC system does not meet this requirement, and the Company is not aware of any technology that would allow its PLC system to effectively meet this requirement in the future. For RF-based communications meters, Zigbee communication from the meter to the customer's HAN device has become the de facto industry standard, and all vendors being considered by the Company use this communications protocol to enable communications to a HAN device.

31. The new AMI system will include Zigbee enabled smart meters that facilitate direct access from the meter to a customer's HAN device for price and consumption information. Customers will be responsible for purchasing and installing their own HAN devices as well as establishing the network connection with the Zigbee interface.

d. Providing Customers With Information On Their Hourly Consumption

32. See (e) below.

e. Enabling TOU Rates And RTP Options

33. The current PLC system meets this requirement through the use of electromechanical retrofitted meters which record hourly interval usage and demand to enable TOU and RTP billing. An RF solution would also meet this requirement. However, an upgraded MDMS system would provide additional support for this technology.

f. Supporting The Automatic Control Of The Customers' Electric Consumption

34. The current PLC system complies with this requirement. Automatic load control is enabled by a signal on the electrical wave. Depending on the vendor solution, an RF system would allow for the same type of control through the Zigbee communications protocols or the solution's RF network.

2. Additional Smart Meter Capabilities Set Forth In The Implementation Order

a. Ability to Remotely Connect And Disconnect

35. The Company's current PLC system can meet this requirement, but would require that new meters with remote service switches be installed in order to comply. All RF Mesh vendors that are being considered have meters with demonstrated remote connect/disconnect functionality. PPL Electric proposes to install meters with the remote connect/disconnect functionality, which is consistent with all other major EDCs in Pennsylvania.

b. Ability To Provide 15-Minute Or Shorter Interval Data

36. Currently, the Company provides sub-hourly 15-minute interval data for all its large commercial and industrial ("C&I") customers. Residential customers are provided with hourly interval data. In order to measure and record sub-hourly usage for all residential customers through the power line carrier system, the Company would need to upgrade the meters of approximately 1.2 million customers to newer electronic meters. However, the PLC system would be severely constrained in collecting the 15-minute interval data for all customers as tested in the pilot program. Furthermore, the current information technology platform and systems are not built to process and store this amount of data.

37. An RF solution would eliminate bandwidth issues associated with providing this data, while also enabling the functionality assuming that the required back office functions (e.g.

an upgraded MDMS system) are in place. The Company plans to deploy a system which supports this functionality at the meter level, but does not propose to build out the IT platform to support this functionality at this time due to cost and lack of market demand. However, with the RF Mesh system, the Company will be able to expand its systems to provide this functionality in the future if and when it is required.

c. On-Board Meter Storage Of Meter Data That Complies With Nationally Recognized Non-Proprietary Standards Such As ANSI C12.19 and C12.22 Tables

38. The current PLC system does not comply with this requirement as the current electromechanical retrofitted meters would have to be replaced with electronic meters. All RF-based solution vendors being considered comply with this requirement, but differ in how they approach the various standards involved. PPL Electric will evaluate RF solution capabilities in support of nationally-recognized non-proprietary standards.

d. Open Standards And Protocols That Comply With Nationally Recognized Non-Proprietary Standards Such As IEEE 802.15.4

39. The current PLC system does not fully comply with this requirement. Only the Company's solid state meters (14% of the existing meter population) comply with this requirement. All RF-based solution vendors being considered comply with this requirement.

e. Ability To Upgrade These Minimum Capabilities As Technology Advances And Becomes Economically Feasible

40. The characteristics of the current PLC system make it increasingly difficult to upgrade due to restrictions with the PLC infrastructure. Furthermore, assessments and pilots conducted by the Company have revealed that it is already pushing the limits of PLC technology. An RF solution would comply with these capabilities and in some cases can provide functionality enhancements over time as requirements evolve.

f. Ability To Monitor Voltage At Each Meter And Report Data In A Manner That Allows An EDC To React To The Information

41. The current PLC system uses electromechanical meters retrofitted with modules that calculate voltage manually, causing a potential loss in accuracy compared to more modern, electronic meters. Additionally, constraints with the current PLC infrastructure limit the frequency of voltage monitoring due to bandwidth constraints. An RF solution would include the use of electronic meters which will allow voltage information to be reported at designated intervals and provided on a near-real-time basis.

g. Ability To Remotely Reprogram The Meter

42. The current PLC system is severely limited with respect to remote programming capabilities. Some functionality changes to meter measurement and register mapping are possible, but there is no capability for meter firmware updates or major functional measurement changes. RF solutions support remote programming of functions and operating system firmware, and provide bandwidth availability through the communications network to enable this functionality.

h. Ability To Communicate Outages And Restorations

43. The current PLC system requires polling (pinging) the meter to obtain power status. The current solution does not allow for "last gasp" or power restoration messages to be sent proactively by the meters, so the system is unable to proactively report an outage and restoration. The current PLC system does have the ability to poll time-stamped outage information from the electronic meters. An RF solution allows for the existing pinging capability, while also using meters which have "last gasp" and power restoration messages. These messages can allow meters to proactively report an outage and restoration.

i. Ability To Support Net Metering Of Customer-Generators

44. The current PLC system supports net metering of customer-generators by changing the normal retrofitted electromechanical meter with an electronic meter. An RF solution would also enable this functionality with the accompanying support of IT systems including the Customer Information System ("CIS").

3. Additional Requirements From The Commission's December 2012 Order

a. Utilization of Smart Meter Data For Bill Ready and Dual Billing

45. PPL Electric currently utilizes meter data for bill ready and dual billing and will continue to offer this functionality to EGSs.

b. Providing at least 12 Months of Account or Meter Level Historical Interval Usage Data Via Electronic Data Interchange ("EDI")

46. PPL Electric currently provides historical interval information at the aggregate account level via EDI and will continue to do this.

c. Participation in an EDEWG Working Group to Define a Solution for Providing Hourly Internal Usage and Billing Quality Internal Usage Data Via a Web Portal.

47. PPL Electric is currently participating in the EDEWEG working group.

d. Providing a Plan to Support Meter Level Hourly Interval Usage Data.

48. PPL Electric currently captures historic hourly or 15-minute interval usage information at the meter level. In the Company's Supplier Web Portal, this information is shown at the aggregate account level and also at the aggregate meter level. PPL Electric will continue to do this under the SMP.

D. VENDOR SELECTION

49. PPL Electric proposes to conduct a Request For Proposal ("RFP") process to select the vendor or vendors to install the new RF Mesh and related systems.

50. The Company proposes to issue RFPs in two phases. Phase 1 will include:

- AMI System (including primary meter supplier, network communication equipment and Head-End software)
- MDMS
- Customer Portal
- NOC
- Project Management Office
- System Integrator
- Meter Asset Management System

Phase 2 will include:

- Meter Installation/Deployment vendor
- Alternate meter vendor for secondary supply of meters

51. Additional details regarding the vendor selection process are set forth in Section IV of the SMP. As explained therein, the Company is not proposing to seek Commission approval of actual vendors, but rather seeks approval of the process for selecting the vendor as described in the SMP. In addition, the Company does not intend to execute contracts with vendors until after the Commission approves the SMP.

E. IMPLEMENTATION PLAN

52. PPL Electric proposes to deploy its AMI system from 2015-2021. From 2015-2017, the Company will build the IT systems necessary to support its AMI system.

53. Deployment of meters will begin with a "Solution Validation" phase which will start in late 2016 through early 2017 and will include a total deployment of up to 50,000 meters. The purpose of this phase is to test the performance of the RF mesh and confirm end-to-end AMI system performance. This solution validation phase will help ensure system performance during deployment.

54. PPL Electric proposes to begin full deployment of meters in 2017 following the Solution Validation phase and to continue deployment through 2019.

55. Following the completion of deployment in 2019, the system will enter a two-year stabilization period (through 2021). This stabilization period will continue the process of fine-tuning the mesh network and back office systems. This time period will also be used to deploy any final system enhancements or upgrades prior to full operation in 2022. Additional details are provided in Section V of the SMP.

F. CYBERSECURITY AND DATA PRIVACY

56. PPL Electric recognizes the importance of implementing and maintaining strong cybersecurity and data privacy measures. The Company maintains an internal workgroup and utilizes third-party experts that focus on cybersecurity and data privacy issues for all of the Company's systems. To ensure that cybersecurity risks are adequately addressed, the Company will utilize its project lifecycle process to aid in creating cybersecurity controls, processes and procedures.

57. The Smart Meter Project will also leverage existing and emerging security standards, including those developed by the National Institute of Standards and Technology ("NIST"). Additional details regarding the Company's cybersecurity and data privacy processes are provided in Section VI of the SMP.

G. ORGANIZATIONAL IMPACTS

58. PPL Electric recognizes that its SMP has potential for organizational impacts. The Company has implemented an organizational change impact analysis and will continue this assessment over the next several years.

59. The Company will implement processes and any necessary procedures to address organizational changes issues. Further discussion is provided in Section VII of the SMP.

H. PROGRAM RISKS

60. The Company recognizes that the SMP will have broad ranging impacts on the Company, its customers and other stakeholders. The Company believes that it is prudent to conduct a comprehensive risk assessment and implement a management process to mitigate risks.

61. The Company has identified several risks associated with implementing the SMP, including but not limited to, new regulatory or legislative requirements, resource availability, customer perception and education, vendor performance, technology obsolescence and complexity of IT efforts.

62. To address and mitigate risks, the Company has developed a risk mitigation plan. The risk mitigation plan includes actions to: (1) conduct ongoing risk management and mitigation, (2) participate in site visits with vendors and peer utilities, (3) engage industry expertise and external program support, (4) use a staged deployment approach to manage the impact of the new systems, (5) use a phased approach to test and operationalize advanced functionality, and (6) conduct due diligence through requirements design and vendor planning. This risk mitigation plan is further described in Section VIII of the SMP.

I. PROGRAM BENEFITS

63. PPL Electric installed its existing metering system in 2002-2004. As a result of installing this system, the Company was able to eliminate its physical meter reading operations, which produced cost savings for customers. These savings have been reflected in the Company's base rate proceedings over the past 10 years.

64. PPL Electric anticipates that it will realize additional benefits associated with implementing its SMP. Including the remote connect/disconnect functionality will reduce the number of physical visits required to customers' premises. Also, the Company will be able to respond to customer requests to connect and disconnect service in a more timely manner which should increase customer satisfaction. The Company also anticipates that its call volumes will decrease regarding reconnection of service.

65. Other benefits include increased power quality, an enhanced ability to detect distribution problems, faster location of outages with the introduction of last gasp technology, improved tracking of unaccounted for energy, enhanced customer service and others which are described in Section IX of the SMP.

66. The benefits of implementing the SMP are difficult to quantify. For example, when implementing the remote connect/disconnect functionality, the Company anticipates a reduced number of service visits to customers' premises. However, the Company may not necessarily reduce its staff to account for this functionality but may use its resources to perform other activities. The Company may also experience lower call volumes, but it is not possible to predict with any accuracy a precise amount by which this would reduce the Company's operating expense. In addition, the Company may experience improved power quality and increased customer satisfaction associated with implementing the SMP. It is not possible to accurately

quantify these types of benefits. Moreover, many of the benefits will not be fully realized until the SMP is implemented.

67. Due to the uncertainty and difficulty in quantifying operational savings associated with implementing the SMP and the delay in fully realizing these benefits, the Company proposes to reflect any savings associated with the SMP in future base rate cases as these savings are realized in the Company's operations. This is consistent with how the Company reflected savings to customers associated with implementing its existing metering system.

J. SMP COSTS

68. The total cost of PPL Electric's SMP is estimated to be approximately $450 million. A high level overview of estimated spending for various components of the SMP is provided in the table below:

Program Component	**Cost Estimate ($ Millions)**
Meters	$284.9
Network & Network Management	$39.3
IT	$77.7
Systems Integration	$8.8
Program Management	$28.6
Communications/Change Management	$10.0
Total	$449.3

69. A further breakdown of the estimated project costs are provided in Section X of the SMP. PPL Electric notes that the costs provided herein and in the SMP are estimates, and PPL Electric proposes to recover its actual costs for implementing the SMP.

K. SMP COST RECOVERY

70. PPL Electric currently recovers its smart meter plan costs through its Smart Meter Rider ("SMR") that was approved by the Commission's *2010 Smart Meter Order* at Docket No. M-2009-2123945.

71. PPL Electric is proposing to recover its costs for the SMP through the SMR with several modifications. The Company is proposing that the SMR be stated as a per-customer charge for all Residential, Small C&I and Large C&I customers. The rate will be updated quarterly and will be based on historical, actual cost data for the prior three-month period with a one-month lag.

72. In addition, PPL Electric will incur costs to develop and implement this SMP before the Commission approves cost recovery. Therefore, the Company proposes to defer qualifying development and implementation expenses and recover them over a three-year period through the SMR following Commission approval of the SMP.

73. The SMR is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year. The revenue received under the SMR for the reconciliation period will be compared to PPL Electric's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year. If SMR revenues exceed SMR-eligible costs, such overcollections will be refunded with interest. If SMR-eligible costs exceed revenues, such undercollections will be collected with interest.

74. As stated above, the Company has provided estimates of the costs to implement its SMP. However, the Company proposes to recover its actual SMP capital costs and expenses through the SMR. Additional details regarding the Company's cost recovery proposals are provided in Section XII of the SMP.

L. CUSTOMER EDUCATION AND OUTREACH

75. PPL Electric understands that customer education and outreach are important for customer acceptance and utilization of smart meter technology. Therefore, PPL Electric has developed a communications strategy to educate customers. PPL Electric's communications related to the Smart Meter Plan will ensure that customers are informed about AMI benefits and the installation experience, including when they can expect new meters. The Company also intends to provide sources of information about AMI, and contact information for scheduling installation appointments. These activities will also include addressing any concerns about the program. In addition to customer communications, PPL Electric will educate and inform employees, stakeholders, members of the media, public officials, and other audiences about why PPL Electric is upgrading to advanced meters.

76. During deployment, PPL Electric proposes to implement a 90-60-30 day communication strategy that provides different levels of communications to customers, employees and community and other stakeholders 90 days, 60 days and 30 days before meters are installed in a specific community or location. The strategy has been used successfully by other utilities across the country. In addition, the Company proposes to conduct a post-installation survey requesting feedback regarding the installation experience and the efficacy of communication materials. Additional details regarding the Company's communications strategy are provided in Section XI of the SMP.

M. POST GRACE PERIOD DEPLOYMENT FOR NEW CONSTRUCTION AND CUSTOMER REQUESTS

77. PPL Electric is proposing to install its existing PLC meters for customer requests and in new construction in each geographic region of its service territory until it has extended the

RF mesh network to that geographic location. Thereafter, PPL Electric will install RF mesh meters for customer requests and new construction in the geographic location.

78. As explained above, PPL Electric currently has a PLC based metering system that reads meters over the power lines. The Company no longer has manual meter readers. PPL Electric is installing an RF mesh network that will read meters over the airwaves. However, the RF mesh communication network will be built out over time in different geographic areas of the Company's service territory. It would not be prudent to install an RF mesh meter in an area where there is no RF communication network because PPL would have no way of reading the meter. It would be very costly and resource intensive to develop micro RF networks or hire manual meter readers to read meters.

79. In addition, PPL Electric's customers already receive many benefits of smart meter technology through the Company's existing AMI system such as hourly reads, TOU service and net metering.

80. For these reasons, and as further explained by Mr. Glenwright in PPL Electric Statement No. 2, it is reasonable for PPL Electric to continue to install PLC meters for customer requests and in new construction until the RF mesh communication network is installed.

N. UNRECOVERED COSTS OF ASSETS TO BE REPLACED

81. PPL Electric's existing meters are not fully depreciated and will not be fully depreciated by the end of the new meter deployment period if the Company continues its existing depreciation schedule.

82. In order to fully recover its costs for its existing meters, PPL Electric proposes to continue recovering depreciation expense on its existing meter assets through distribution base rates. When the Company submits its next base rate case, PPL Electric will accelerate the period

over which it will recover its remaining investment in its existing assets to coincide with the completion of the new meter deployment period.

83. PPL Electric requests Commission approval of this methodology for recovering its unrecovered investment in its existing AMI assets. If the Commission does not approve the cost-recovery methodology, the Company requests Commission approval to accelerate its meter depreciation upon approval of this SMP and recover the increased depreciation expense through the SMR.

O. METER TESTING

84. PPL Electric also has developed a strategy to address in-service and removed watthour meter testing during full deployment in years 2017 to 2019. In regard to in-service periodic testing of watthour meters, the Company will appropriately adapt its current sample process to ensure that in-service testing continues to meet or exceed the requirements contained in 52 Pa. Code § 57.20(e).

85. With regard to testing removed watthour meters during full deployment, the Commission's *Implementation Order* exempted all electric distribution companies required to install smart meter technology from compliance with 52 Pa. Code § 57.20(h), which states, "A service watthour meter which is removed from service shall be tested for "as found" registration accuracy." Nevertheless, the Company will implement a "Deployment Sample Process" to identify a statistically significant random sample of removed meters. This sample of removed meters will be flagged for registration accuracy testing and returned to the Company's meter test lab as they are removed from service by the deployment vendor.

86. In addition PPL Electric will hold all removed meters for two billing cycles before allowing them to be retired. This will allow any customer billing concerns to be addressed and provide the ability to locate the stored meter for accuracy testing.

IV. CONCLUSION

As discussed above, PPL Electric Utilities Corporation has spent considerable time and effort in evaluating and proposing a cost-effective Smart Meter Plan that will provide customers with the Smart Meter functionalities required under Act 129 and those additional capabilities set forth in the Commission's Smart Meter Implementation Order.

WHEREFORE, for all of the foregoing reasons, PPL Electric Utilities Corporation respectfully requests that the Pennsylvania Public Utility Commission enter an Order by December 31, 2014 to:

(1) Approve this Petition;

(2) Approve the Company's Smart Meter Plan without modification;

(3) Approve the Company's cost-recovery proposals;

(4) Find that the Smart Meter Plan fully complies with Act 129 and the Commission's *Implementation Order*; and

(5) Grant any waivers that may be necessary for PPL Electric Utilities Corporation to implement its Smart Meter Plan, as filed.

Respectfully submitted,

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Dated: June 30, 2014

Attorneys for PPL Electric Utilities Corporation

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation for Approval of Its Smart Meter Technology Procurement and Installation Plan	: : :	Docket Nos. P-2014-___________ M-2009-2123945

VERIFICATION

I, Renae G. Yeager, being the Director – Distribution, Regulatory & Business Affairs for PPL Electric Utilities Corporation, hereby state that the facts above set forth are true and correct to the best of my knowledge, information and belief and that I expect that PPL Electric Utilities Corporation to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Date: June 26, 2014

Renae G. Yeager
PPL Electric Utilities Corporation
Director – Distribution, Regulatory
& Business Affairs

PPL Electric Exhibit No. 1

Before the

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PPL Electric Utilities Corporation

Smart Meter Technology Procurement and Installation Plan

Docket Nos. P-2014-__________
and M-2009-2123945

June 30, 2014

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I. Executive Summary

PPL Electric Utilities Corporation ("PPL Electric" or the "Company") was one of the first investor-owned utilities in North America to deploy an Automated Metering Infrastructure ("AMI"). The Company deployed its initial AMI solution beginning in 2002, utilizing a Power Line Carrier ("PLC") technology wherein data from meters is transmitted via existing power line infrastructure. Through the course of its initial implementation, which took place from 2002 – 2004, PPL Electric realized several operational and customer benefits including the automation of monthly meter reads for all customers. A Meter Data Management ("MDM") system was added in 2006 to support processing of the meter data being collected from the AMI system and to interface directly with a customer portal. As a result, PPL Electric was one of the first utilities in the country to present hourly usage data to all customers.

In 2009, PPL Electric submitted its Smart Meter Filing as required by the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission") describing compliance with PA Act 129 and the Commission's subsequent Smart Meter Implementation Order. In the proceedings which followed, the Commission determined that PPL Electric's AMI solution was not fully compliant with all legal and regulatory requirements. In particular, the Commission cited the inability of the Company's solution to provide direct access to and use of pricing information, and the need for further evaluation regarding the 15-minute interval data requirement.

- PPL Electric responded by launching a series of pilot programs to evaluate the impact of upgrades and extensions to the PLC AMI solution. In parallel, the Company performed a series of assessments, with industry expertise, to determine the technical limitations of that solution. These assessments and pilots led to several conclusions: The existing PLC AMI solution is not fully compliant with the above-referenced legal and regulatory requirements.

- Components of the existing PLC AMI solution were approaching the end of their useful lives. The Company has witnessed increased meter failure rates over the past several years due to the age of the solution.

- Market assessments and pilot programs conducted by PPL Electric validated the increasingly obsolete nature of PLC technology, which was determined to be limited in both scalability and functionality versus competing AMI technology types. This obsolescence also meant that without a new solution, PPL Electric would be unable to provide the same level of service to its customers as could be provided by peer utilities.

As a result, PPL Electric proposes to implement a Radio Frequency Mesh ("RF Mesh") AMI technology type for its future smart metering solution. The Company believes RF Mesh represents the best technology option that exists in the marketplace today with respect to solution costs, compliance with legal and regulatory requirements, and PPL Electric's current and future business needs.

PPL Electric's proposal is to fully replace its current system with an RF Mesh AMI solution. This includes the replacement of all meters (approximately 1.4 million). The Company is also proposing to replace the supporting systems needed to enable advanced metering functionality, including the Head End system, the MDM, a Meter Asset Management ("MAM") tool, the Customer Portal tool, and the associated Information Technology ("IT") architecture. The proposed solution also calls for the addition of a Network Operating Center ("NOC") to be implemented prior to deployment. This solution will allow the Company to ensure a high level of operational performance, maintain network and infrastructure integrity, and effectively manage the deployment of the new metering system. Additionally, changes to customer data and billing will require changes to PPL Electric's Customer Information System ("CIS"). An analysis is currently underway to assess the scope of this impact. After completing this analysis, PPL Electric anticipates filing an amendment to this Plan to implement the CIS changes and seek recovery of the associated costs.

A diagram showing these proposed components is provided in Figure 1 – SMP Scope High Level Overview.

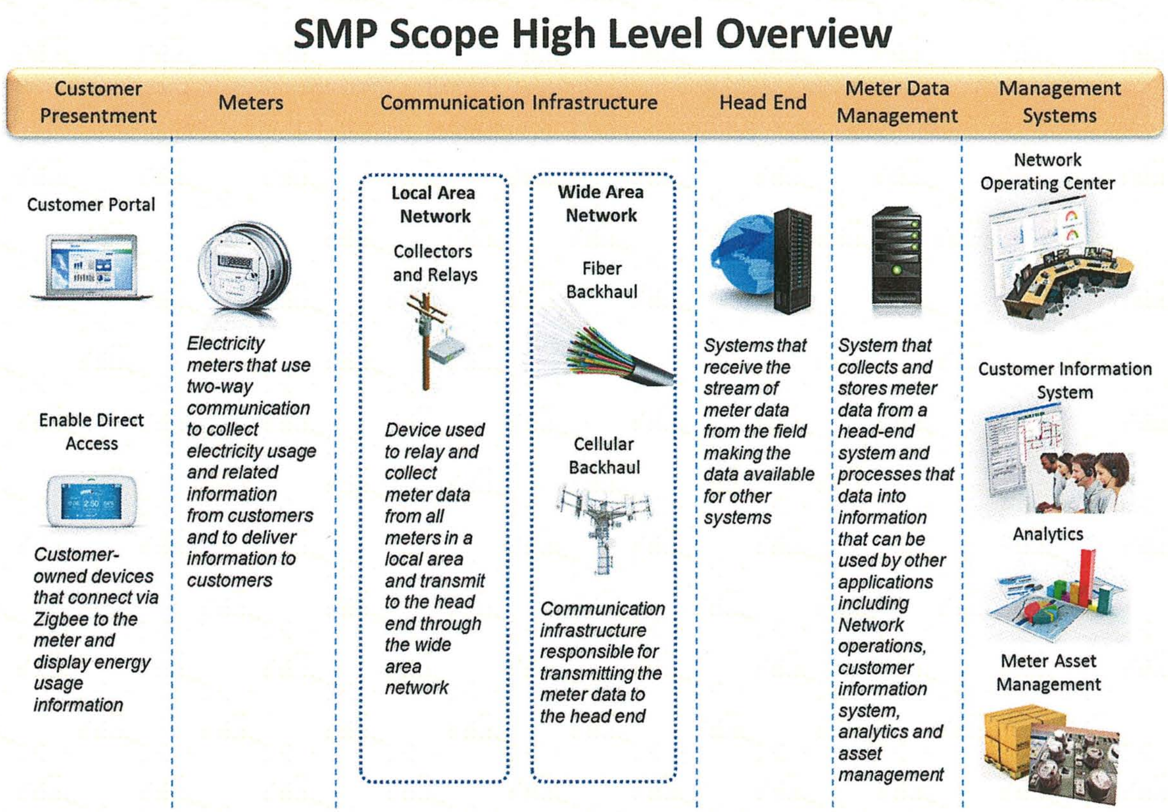


Figure 1 – SMP Scope High Level Overview

The decision to replace the existing solution was based on many factors, including:

Regulatory Compliance

PPL Electric determined, based on the above-referenced pilot programs and assessments, that upgrading the existing PLC AMI solution would not allow the Company to comply with all legal and regulatory requirements. An RF Mesh AMI solution type as proposed herein will allow the Company to meet these requirements.

Additional detail regarding compliance with legal and regulatory requirements is provided in Section III. Technology Assessment.

Solution and Systems

The Company believes that an RF Mesh AMI solution and supporting systems provide the strongest operational performance and the most flexibility for future business and regulatory needs. This type of network provides a solution that is not constrained by the existing distribution network and which allows for flexible expansion opportunities as the Company experiences growth. An RF Mesh solution also provides the capability for proactive messages, such as outage and restoration notification, an improvement over the current system which requires active pinging of the meters to detect power outage status. Additional details regarding the technical capabilities of the solution are provided in Section III. Technology Assessment.

Prudency

For the reasons discussed above, PPL Electric would need to replace the majority of its current meters regardless of the solution chosen. In addition to being non-compliant, the original electromechanical meters (~1.2 million) deployed in the existing solution are no longer available in the market. Based on this and other factors described in more detail in the following chapters, PPL Electric determined that upgrading the PLC AMI solution would not be a prudent expenditure.

Technology Evolution

With its current solution, PPL Electric remains an outlier within the expanding AMI community. Very few Investor Owned Utilities operate a similar technological solution within the US, whereas RF Mesh continues to exhibit industry dominance and expanded growth. An RF Mesh solution therefore provides PPL Electric with a substantial pool of peer companies with which to collaborate and benchmark. This includes the Company's peers in Pennsylvania, all of whom have elected to deploy an RF-based AMI solution to comply with Act 129 and Implementation Order requirements.

Proposed Deployment Schedule and Cost:

With Commission approval, the proposed solution will be deployed beginning with an IT system upgrade to be completed by the end of Q3 2016. Deployment of meters will begin in 2016 and will be implemented in three phases: a solution validation phase in late 2016 and early 2017 to validate full system functionality, deployment processes and field tools, followed by a full deployment phase from 2017 – 2019. The third phase will consist of a two-year system stabilization period from 2020 – 2021. This phase will be used to optimize system performance and ensure all functionality is delivered. In order to accomplish this timeline, activities to support vendor procurement began in May 2014. PPL Electric will not execute contracts with selected vendors until approval of this Plan by the Commission. Further details on the deployment process are provided in Section V. Implementation Plan.

The full cost of this solution through the deployment timeframe is estimated to be approximately $450 million. This cost is explained in more detail in Section X. Financial Overview. PPL Electric's projection of costs for the various components of the SMP are high level estimates based on data provided by potential vendors in response to the Company's Requests for Information ("RFIs") and further based on the Company's business experience. These high level estimates are subject to change for a variety of reasons, including, but not limited to, increases in vendor prices, changes in project scope, changes in the implementation timeline, unforeseen complications or changes in regulatory requirements. The cost estimates are not precise and will be revised over the life of the project. PPL Electric intends to recover its actual smart meter costs through the Smart Meter Rider whether they are more or less than the Company's initial estimates.

A high-level view of the schedule is shown below in Figure 2 - High Level Program Schedule.

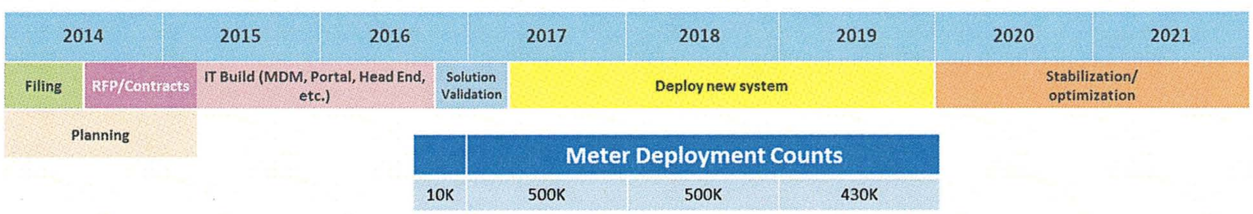


Figure 2 - High Level Program Schedule

Objectives of this Plan

The objectives of this Smart Meter Plan are to:

- Provide a summary update on final pilots conducted by the Company
- Describe the process which led to the proposal to replace the existing PLC AMI solution with an RF Mesh AMI solution
- Provide detail about the key activities needed to select vendors and the proposed timeline for deployment, including when advanced metering functionality will be available to customers
- Describe the Company's plan to implement the RF Mesh AMI solution
- Describe a plan to address cyber security and privacy of customer data concerns
- Discuss organizational impacts
- Discuss program risks and mitigation strategies
- Describe program benefits and present the financial overview and the Company's proposed cost recovery mechanism
- Define the Company's communications strategy

II. PPL Electric Background

PPL Electric provides electric distribution, transmission and default generation services to approximately 1.4 million customers in a certificated service territory that spans approximately 10,000 square miles in all or portions of 29 counties in eastern and central Pennsylvania. PPL Electric is a "public utility" and "electric distribution company" ("EDC") as those terms are defined under the Public Utility Code, 66 Pa. C.S. §§ 102 and 2803.

A. Smart Meter Program History

PPL Electric was one of the first Investor-Owned Utilities in the country to implement an Automated Metering Infrastructure system. The technology chosen for that system was a PLC solution purchased from Aclara. Under PLC technology, the meters are read remotely and the data is transmitted back to PPL Electric through the power line. PPL Electric replaced all meters, built equipment into each substation to collect meter data, and built an IT infrastructure to allow for the collection of data to support a variety of processes, including billing and settlement, and to pave the way for advanced business functionality. This infrastructure incorporated the MV-90 system used for large commercial and industrial customers which was already in place at the time. A MDM system, also purchased from Aclara, was added in 2006 to support processing of the meter data being collected from the AMI system and to interface directly with a customer portal. As a result, PPL Electric was one of the first utilities in the country to present hourly usage data to customers.

In 2008, the legislature adopted Act 129 of 2008 ("Act 129"), which amended the Public Utility Code and inter alia, required all Pennsylvania utilities with over 100,000 customers to deploy smart meters. In particular, Act 129 described smart meter technology as follows:

> *"Smart meter technology" means technology, including metering technology and network communications technology capable of bidirectional communication, that records electricity usage at least an hourly basis, including related electric distribution system upgrades to enable the technology. The technology shall provide customers with direct access to and use of price and consumption information. The technology shall also:*
>
> *(1) Directly provide customers with information on their hourly consumption.*
> *(2) Enable time-of-use rates and real-time price programs.*
> *(3) Effectively support the automatic control of the customer's electricity consumption by one or more of the following as selected by the customer:*
> *(i) the customer;*
> *(ii) the customer's utility; or*
> *(iii) a third party engaged by the customer or the customer's utility*

On June 24, 2010, the Commission issued an Implementation Order directing that a covered EDC's smart meter technology should support the following 15 capabilities:

<u>*Mandatory Act 129 Requirements:*</u>

1. Bidirectional data communications

2. Reading usage data on at least an hourly basis once per day

3. Providing customers with direct access to and use of price and consumption information

4. Providing customers with information on their hourly consumption

5. Enabling Time of Use (TOU) rates and Real-Time Pricing (RTP) programs

6. Supporting the automatic control of the customers' electric consumption

<u>*Additional PA PUC Implementation Order Requirements:*</u>

7. Ability to remotely disconnect and reconnect

8. Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties, and an RTO on a daily basis, consistent with the data availability, transfer, and security standards adopted by the RTO

9. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables

10. Open standards and protocols that comply with nationally recognized non-proprietary standards such as IEEE 802.15.4

11. Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

12. Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information

13. Ability to remotely reprogram the meter

14. Ability to communicate outages and restorations

15. Ability to support net metering of customer-generators

Additionally, the Implementation Order established a mechanism for recovery of smart meter deployment costs, provided guidance on required filings and communications pertaining to Smart Meter Implementation and Procurement, and established a transition period for utilities to develop a Smart Meter Plan with requirements to provide smart meters upon customer requests and new construction.

In accordance with the schedule established by the Commission, PPL Electric filed its initial Smart Meter Plan with the Commission on August 14, 2009. In this filing, PPL Electric stated that the then-current system was compliant with the requirements of Act 129 and the

Implementation Order. Therefore, the Company proposed to conduct a series of pilots and evaluations to test and enhance its existing AMI system.

On June 24, 2010, the Commission entered its order in the Smart Meter proceeding. In its order, the Commission revised certain aspects of the Company's Smart Meter Plan and found that PPL Electric's current metering system did not fully comply with the requirements of Act 129. Specifically, the Commission stated that:

> *Since PPL Electric's existing system does not fully meet all Act 129 requirements, it should use the Grace Period Pilot programs to fully develop a Plan, to be filed with the Commission, to fully comply with Act 129*

Following the Commission's Order, PPL Electric undertook a series of pilot programs to test the abilities of the Aclara PLC system and reported to the Commission annually on the status of these pilots. The results of the pilots are discussed in Section III. Technology Assessment.

In addition, PPL Electric conducted a current state assessment of its smart metering system in 2011, including an analysis of the current state architecture and recommendations for the future system. PPL Electric contracted Black & Veatch, a recognized utility consulting firm with substantial experience in smart metering, to support this effort.

On May 4, 2012, the Company filed a petition requesting approval to modify its Smart Meter Plan and to extend its grace period to give the Company additional time to further test and evaluate the most cost-effective ways to meet the Act 129 requirements. *Petition of PPL Electric Utilities Corporation for Approval to Modify Its Smart Meter Technology Procurement and Installation Plan and to Extend its Grace Period,* Docket No. P-2012-2303075 ("May 2012 Petition").

In its Order entered August 2, 2012, the Commission granted an extension until June 30, 2014, for the Company to file its Final Smart Meter Plan.

In December 2012, the Commission entered a further order establishing additional requirements for smart meter plans. *Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, Final Order entered December 6, 2012. Specifically, the Commission directed EDCs to include plans to support exchange of smart meter data between EDCs and Electric Generation Suppliers ("EGSs") and third parties. The order included direction to EDCs to support:

1. Utilization of smart meter data for bill ready and dual billing
2. Providing at least 12 months of account or meter level historical interval usage data via Electronic Data Exchange (EDI)
3. Participation in an EDEWG working group to define a solution for providing hourly interval usage and billing quality interval usage data via a web portal
4. Providing a plan to support meter level hourly interval usage data

In July 2013, PPL Electric contracted with IBM to assist the Company in the alignment of smart meter activities to program goals and a detailed advanced metering technology assessment. Requests for Information were issued to solicit vendor technical and cost information from the marketplace. The Company also performed a financial analysis to support this Plan and established a Smart Meter Plan Roadmap for the next several years. Details on these assessments are provided in the appropriate chapters of this Plan.

PPL Electric has filed annual updates regarding progress of its SMP since submitting its initial filing in 2009, and has conducted multiple stakeholder meetings to provide updates on the progress of pilot programs and other matters of importance related to the SMP. Representatives from the Office of Consumer Advocate ("OCA"), Pennsylvania Utility Law Project ("PULP"), PP&L Industrial Customer Alliance ("PPLICA"), Reliant Energy, PA Coalition Against Domestic Violence, various Commission representatives, and other interested parties attended one or more of these stakeholder meetings.

The Company will continue to provide annual smart meter plan updates and meet with interested stakeholders in addition to ad-hoc updates basis as necessary and appropriate.

III. Technology Assessment

Following the Commission's June 24, 2010 Order, PPL Electric conducted several pilots to determine if its existing smart metering technology, with significant upgrades, could meet all of the requirements of Act 129 and the Commission's Implementation Order. In addition, PPL Electric evaluated the latest smart metering technologies in the marketplace in order to better understand the differences between upgrading the current system and installing a new one. PPL Electric communicated the status of these pilot programs to the Commission on an annual basis.

In 2013, PPL Electric initiated an evaluation of next generation AMI technologies to assess current and future smart meter technology. The objective of the evaluation was to gain an understanding of new AMI technologies that exist in the marketplace. The assessment focused on several key components of the smart metering system:

- Advanced Metering Infrastructure (AMI) Solution – includes smart meters, communications infrastructure, and head end technology
- Meter Data Management System (MDM)
- Customer Web Presentment Portal
- Network Operating Center (NOC)
- Meter Asset Management solution (MAM)

The technology assessments were conducted simultaneously and in parallel with ongoing pilot programs to determine the feasibility of upgrades to the current system.

A. SMP Pilot Programs

Beginning in 2009, PPL Electric provided annual communications to the Commission on the status of its pilot programs. These communications included Stakeholder Meetings and Annual Reports, the last of which was submitted in 2013. These annual reports included detailed descriptions of each of the pilots, status, and results.

Based on the pilots, PPL Electric concluded that the existing PLC AMI solution was technically limited in its ability to fully comply with legal, regulatory, and future business requirements. A significant barrier to this technology is the limited scalability, in terms of network bandwidth, for future uses. Additionally, the inability of the PLC network to generate proactive alarms and messages from meters, including outage, restoration, voltage, and temperature was also realized through the pilot programs.

Two pilot programs were particularly important to PPL Electric's decision to proceed with an RF Mesh solution. First, the TWACS 20 pilot tested the ability of the existing system to provide 15-minute interval read data as well as other meter-level data (voltage, temperature, etc.). This pilot concluded it would not be possible to read all meters for 15-minute intervals on a constrained substation while still maintaining key performance metrics (e.g. billing read performance, hourly read performance). Second, the In-Home Display pilot project concluded that the Wi-Fi technology utilized in this pilot would need to have some significant hardware and software improvements, which could not be supported by the existing solution, in order to provide an effective In Home Display system to support the direct access requirement.

Based on these results, and others, the Company concluded its current AMI solution could not fully meet the requirements of Act 129.

B. Existing AMI Solution Assessment

Concurrently with early pilots, PPL Electric conducted a detailed assessment in 2011 to determine whether upgrades to its AMI solution could meet current and future business needs. This process considered both the functionality of the AMI solution and the supporting IT architecture. The assessment, which was supported by Black & Veatch, was divided into three areas:

1. Development of current and future requirements;
2. Assessment of how the current Aclara system meets PPL Electric's requirements; and
3. Analysis of proposed upgrades and their ability to meet future requirements.

During this assessment, PPL Electric determined that the system was operating at its maximum realistic throughput at the Company's larger substations due to the increasing bandwidth needs of new smart meter functionality, such as gathering frequent meter reads. Additionally, the assessment concluded that the future system requirements dictated by Act 129 and the Implementation Order would create additional traffic on the communications network. This additional traffic would exacerbate existing problems with bandwidth and would eventually adversely impact system performance.

The Company also explored the specific Act 129 and Implementation Order requirements that would most stress the existing advanced metering infrastructure. These included voltage information, outage information, historical read collection, and interval data collection. It was predicted that the additional data required by more frequent interval data collection would result in quadrupled increase in network traffic alone, which the current system would not be able to support without significant enhancement. This would be especially true for the initiation of 15 minute interval reads, which would result in an approximately four times increase in data traffic.

To address these concerns, the Company concluded that it should explore the following:

1. Extend the useful life of PPL's TWACS system through system upgrade investments
2. Adopt accelerated meter replacement strategy
3. Ensure full vendor support of upgrade development to technology roadmap to limit exposure of future investments

The Company also began considering upgrades to the existing investment and initiated additional pilots to test functionality.

During this period, PPL Electric began experiencing increasingly higher meter failure rates. PPL Electric's meter population consists of both electromechanical and solid state meters. The population demographic is 86% and 14% respectively. A typical mature meter population experiences a low failure rate during the asset life of the meter. An industry standard failure rate for a meter population during its useful life is approximately 0.5%. For PPL Electric's population of 1.4 million meters, a failure rate consistent with the industry standard would realize as approximately 7,000 meter replacements per year. PPL Electric experienced approximately

28,000 failed meters in 2013 – four times the industry standard. The Company expects this trend to continue growing at an accelerated rate. Figure 3 shows PPL Electric's historic meter failure trend.

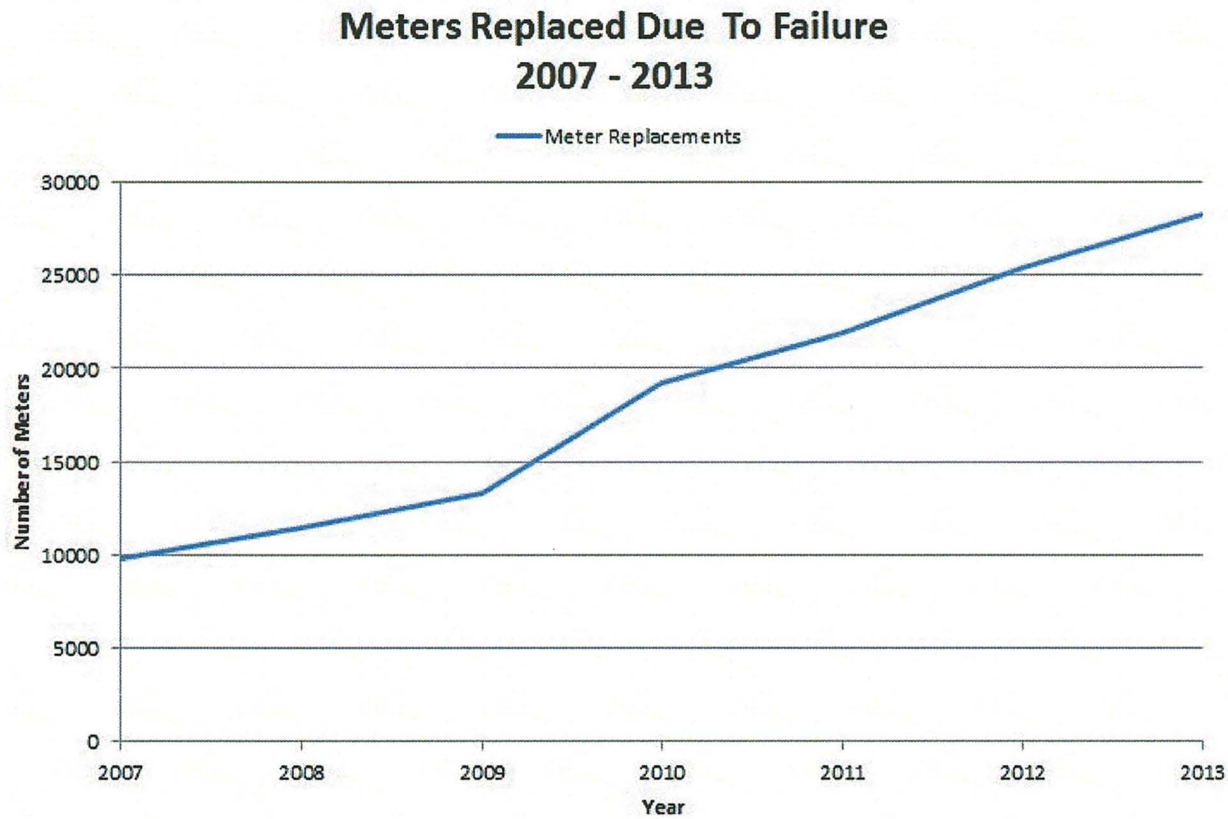


Figure 3 - Historic Meter Failure Rates

An increase in failure rates is most likely attributable to the tendency of this type of equipment to "wear out" over time as electrical components (early generation communication modules) fail due to electrical and thermal stresses. The upward trend in meter failure rates is a leading indicator that meters installed on PPL Electric's system are reaching the end of their useful life. Furthermore, the Company recognizes that AMI communications hardware installed during the initial AMI deployment is the same age as the meter population and is also approaching the end of its useful life. Of note, customers have largely received the benefits of the Company's existing metering system as it is nearing the end of its useful life.

As stated in its 2013 Annual Filing (2013 Annual Smart Meter Filing to the Commission, Docket No. M-2009-2123945), PPL Electric initiated an evaluation of next generation AMI technologies to assess current and future smart meter functionality. The need for an assessment of the AMI solution was motivated by several factors, primarily the non-compliance of the AMI solution as described by the Commission. The objective of the evaluation was to gain a better understanding of new AMI technologies that exist or will exist in the marketplace. Also, the Company wanted to gain additional information about how these technologies could meet the Company's future requirements. PPL Electric hired IBM for this work and the evaluation consisted of the following areas:

- Development of smart meter goals,
- Technical assessment of mass market and large commercial and industrial metering systems, and
- Technical assessment of IT requirements (including MDM) and network communications

Beginning in late 2013, the Company established the following goals for smart metering and related technologies as described below:

> PPL's smart meter plan will address PA Act 129 and Implementation Order requirements as well as attempt to address current and future business requirements through a 20 year horizon.
>
> PPL's smart meter solution will:
> - Encompass new or existing meters, communications networks, integrated system architecture and advanced analytics.
> - Maintain or enhance the customer experience by providing operational functionality consistent with core business requirements and an asset centric business model.
> - Provide a stable, robust, and flexible platform that will facilitate market driven choices for customers through third party market providers (EGSs, CSPs, retailers, etc.).
> - Establish a flexible foundation for possible integration into broader smart grid technologies which may include distribution automation and grid monitoring.

These goals provided important direction for the next stage of the assessment, which focused on the three primary technology types that in aggregate dominate the AMI marketplace in the United States and around the world. These technology types are shown in Figure 4.

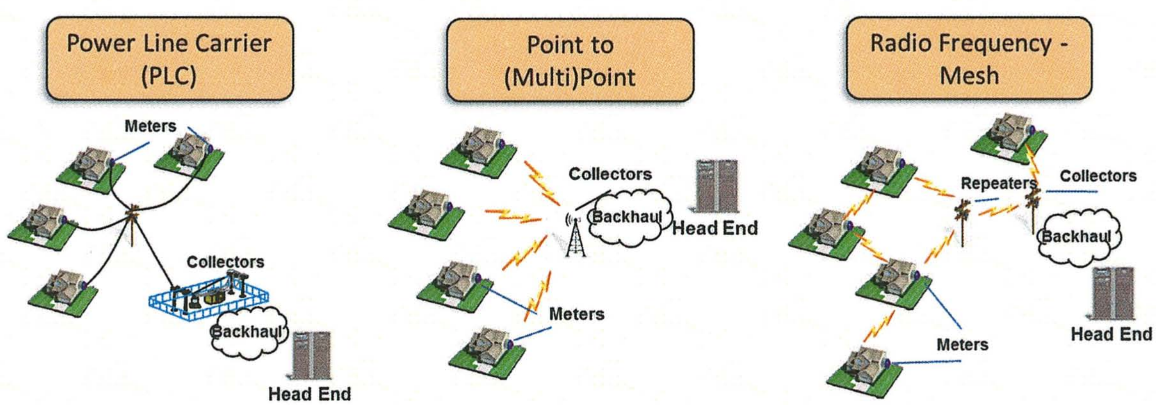


Figure 4 - AMI Technology Types

PPL Electric began with an analysis of the current-state metering solution (PLC) followed by a requirements identification phase. A series of workshops were held with subject matter experts from PPL Electric and IBM. These workshops discussed available solutions, strengths and weaknesses of available technology types, and inter-operability with the Company's current AMI IT infrastructure.

The areas of evaluation focused on technical components of the different solution types. The outcomes of this phase supported the issuance of a RFI.

Following this, the Company generated a high-level list of functional requirements for metering technology, head end technology, and software / information technology. Solution types were evaluated based on vendor RFI responses across several categories. Evaluation categories included compliance with Act 129 and Implementation Order requirements, alignment with the Company's goals for smart metering, financial / commercial risk, meeting functional requirements, meeting IT and network requirements, and resilience / maturity of the proposed system.

Each vendor's RFI solution was evaluated by the Company with input from key business units within PPL Electric. The evaluation process included communications with relevant PPL Electric internal stakeholders, subject matter expertise provided by IBM, and a series of workshops to discuss the received responses. Vendors and technology solutions were evaluated in the categories shown in Figure 5.

- **Financial**
- **SMP Vision Themes**
  - Core Business
  - Enable Choice
  - Analytics
  - Integrated System
  - Act 129 Compliance
- **Functional Requirements**
  - **Meter**
    - Firmware
    - HAN
    - Operational
    - Outage Management
    - Pricing / Programs
    - Security
    - Standards
  - **Head End**
    - Firmware
    - Network
    - Operations
    - Outage Management
    - Security
    - Smart Grid
    - Standards
- **IT**
  - Integration / Architecture
  - Security
  - Platform
  - Support
- **Other Areas**
  - Network Design
  - Backhaul
  - Bandwidth / Latency
  - Resilience / Maintenance
  - Maturity

Figure 5 - Evaluation Categories for AMI Solution Evaluation

In addition to technical and business requirements, PPL Electric requested detailed cost information from solution vendors. A financial analysis was performed based on the submitted cost data, and forms the basis for the anticipated total solution cost. A detailed description of the financial analysis, including the overall solution costs, is provided in X. Financial Overview.

As a result of these evaluations, the Company proposed the adoption of a new technology type for its future metering system. Specifically, the proposal is to replace its current system with an RF Mesh solution type.

Based on the Technical Assessment, PPL Electric concluded the existing PLC technology has limited ability to meet current regulatory and future business requirements. Furthermore, the pilots performed by the Company have shown expansion of the PLC technology to meet requirements is in some cases high-cost and high-risk. For example, the ability to meet the regulatory requirement to provide 15-minute interval data requires a high degree of network bandwidth. This in turn would place unreasonable stress on the bandwidth of the current system. The current system vendor has created a roadmap to address these issues. However, in some cases, such as Home Area Network ("HAN") technology, no solution has been shown to be commercially viable.

The Technical Assessment evaluation also showed that the market share of PLC technology in North America has been steadily declining since PPL Electric first deployed its current system in 2002. Since 2002, several large utilities in North America have chosen to deploy RF-based systems and have developed best practices and lessons learned from their deployments; PPL Electric plans to leverage these practices through site visits, through collaboration meetings with peer utility companies, and by retaining consultants who have experience with deployments of RF Mesh solutions. Additional detail in this regard is provided in Section VIII. Program Risks. It is the Company's belief that an RF Mesh solution is the optimal alternative for the Company and its customers.

An RF Mesh solution will meet Act 129 and Implementation Order requirements in addition to the future business needs of the Company. PPL Electric plans to undergo a thorough vendor selection process to select the key partners for this deployment; this process is described in detail in Section IV. Vendor Selection for Future Technologies.

C. MDM Assessment

In parallel with the effort to solicit information for an AMI solution, PPL Electric conducted a similar effort to obtain market information for an upgrade to the existing MDM system. This assessment was completed with support from Black & Veatch.

PPL Electric's MDM has provided initial capabilities to process smart meter data, but is currently not capable of supporting the full breadth of Act 129's stated functionalities without significant development, upgrading, and customization. Thus, PPL Electric needed to effectively address these risks while also addressing the increased functional requirements defined by Act 129.

In order to accurately address the requirements of Act 129 and the evolving business needs of the utility, PPL Electric assessed the MDM functionality currently used by each internal stakeholder group. The Company used this information to create a baseline of current business needs into which was integrated the new Act 129 requirements. Future requirements for Smart Meter data from these internal operations as well as those expected to support the growing needs of retail markets were also considered.

In performing this evaluation of MDM alternatives and determining a prudent, cost effective strategy to meet Act 129 requirements, PPL Electric established three (3) underlying principles to guide the process. These guiding principles included:

1. <u>Compliance with Act 129 requirements</u>: The recommended MDM solution strategy must, first and foremost, enable the Company to fully support all of the Act 129 functional requirements as set out in the Act itself and the supporting Implementation Order.
2. <u>Enable future operational performance improvements</u>: As PPL Electric transitions to a future state of operations, the MDM solution must not only replace current functionalities and enable the required Smart Meter functionalities, but must also support advanced, future operational capabilities to continue to improve the Company's operational effectiveness in supporting Retail Market participants and efficiently managing the distribution system.
3. <u>Mitigate risks</u>: The recommended MDM solution strategy must help PPL Electric mitigate future risk associated with evolving future business needs and potential technology obsolescence.

PPL Electric examined possible MDM solutions that could accomplish the requirements set out by Act 129 and support the Company's future business needs. PPL Electric completed a detailed effort to understand and document all of the key functional capabilities currently supported by the Company's MDM, the operational problems currently encountered, the requirements that are associated with compliance with Act 129 functional capabilities, as well as the future capabilities needed to fulfill the Company's future needs.

Several actions were taken in support of this effort. First, PPL Electric developed a set of common MDM requirements, utilizing the Company's consultant and based on previous experience with other utilities core MDM capabilities. Additional requirements were compiled based the Company's initial MDM implementation in 2005 and based on previous PPL Electric smart meter pilot projects (described in detail in Section III. Technology Assessment). The Company also conducted detailed workshops to fully discover, review, and establish the full breadth of stakeholder requirements for meter data processing within PPL Electric.

Based on the detailed MDM requirements documented, PPL Electric developed a RFI that was issued to potential MDM vendors. The RFI described the Company's objectives, Act 129 compliance requirements, current situation, the three potential implementation scenarios, the desired optional capabilities, and the cost details desired. The RFI was issued to PPL Electric's current MDM vendor to get a complete understanding of its suggested approach to support the additional capabilities required by Act 129, correct current deficiencies which impede effectiveness, and implement the ability to support the Company's future needs. The RFI was also issued to the other top five MDM vendors in the industry as identified by PPL Electric's consultant.

PPL Electric reviewed each vendor's RFI response and assessed the capability of each MDM solution in meeting the Company's stated MDM requirements.

This provided a basis of confidence for PPL Electric to judge whether its current requirements, the Act 129 requirements, or its future requirements were:

a. Commercially viable to be delivered completely from at least one vendor
b. Reasonable across all of the vendors so as to provide for a competitive vendor selection process in the future

PPL Electric conducted four days of detailed workshops to examine each vendor's response to each of 215 specific requirements across 15 functional categories. These categories included the following:

- Synchronization of Data & Asset Management
- Field Activities & Work Order Management
- AMI Deployment Support
- AMI Data Management
- Validation, Estimation, and Editing (VEE)
- Billing Support
- Real Time Operations
- Revenue Protection
- Exception Reporting
- Load Research
- Retail Energy Supplier Support (Forecasting, Settlement, PLC)
- Planning & Engineering
- Customer Data Presentment
- Demand Control/Demand Response Support
- Outage Management

PPL Electric reviewed all of the requirements which directly related to Act 129 functional requirements as well as those which contained interdependence on any potential new AMI system. Following the initial receipt and evaluation of the responses from the vendors, PPL Electric scheduled detailed, on-site reviews of each vendors proposed solutions and live demonstrations of each vendor's commercial MDM product. These on-site visits served to validate the Company's understanding of the proposed solutions and confirm its assessment of the commercial availability and viability of potential solutions to meet current and future business needs, including the requirements of Act 129.

Finally, any remaining cost information was reviewed with the vendors to ensure PPL Electric had a sound understanding of the expected costs of implementing the proposed MDM solutions.

Based on the detailed pricing information provided by the vendor responses, PPL Electric was able to determine the estimated costs that may be incurred to implement the potential MDM solutions. These cost estimates were based on the following inputs:

- Vendor-specific costs as detailed directly within each vendor's response
- Estimates of system hardware costs based on typical PPL Electric internal IT costs
- Estimates of internal PPL Electric program support costs required to support the deployment of a new MDM system based on role types and projected basis of efforts
- Estimates of probable system integration costs based on deployments by other, like sized utilities deploying new MDM systems

Based on this detailed cost model, PPL Electric was able to estimate costs associated with the various implementation scenarios.

The deployment of a new MDM system at PPL Electric will require the migration of existing MDM capabilities and databases from its existing system. To address the incremental complexity of replacing an existing system, the Company developed an initial, high level deployment plan. The plan establishes sequencing, phasing, and alignment of a new solution deployment. The plan also begins the process of providing planning and cost timing insights and will be updated pending a final MDM solution selection

The assessment concluded that maintaining, upgrading and customizing PPL Electric's existing MDM solution poses significant risks of obsolescence. In addition, the existing solution provides the least ability to comply with PPL Electric's requirements (including Act 129). PPL Electric's proposal is to replace the existing MDM currently in use with a new MDM solution. A new solution will better address the Act 129 requirements and PPL Electric's business needs.

D. Customer Portal Assessment

A similar effort was conducted in parallel with the AMI and MDM assessments to evaluate the upgrade of the Company's customer portal system ("Energy Analyzer"), which presents energy usage information to customers via a web interface. Energy Analyzer was deployed to customers in June 2007. Concerns around a plateau in customer engagement and the dated nature of the tool prompted a marketplace assessment of customer portal vendors in late 2013.

The assessment process was carried out by first developing high-level requirements for the new PPL Electric Energy Analyzer tool in both customer service and IT areas, followed by an evaluation of web-based tools and a recommendation. Teams for this assessment were created and divided into:

- Communications and Education
- Market Research
- Customer Call Centers
- Business Account Specialists
- Customer Programs
- Customer Contact – Technology
- Advanced Metering
- Application Development

The Company developed a series of over 40 requirements for inclusion in an RFI. These included examples such as the ability to set up home audit and appliance recycling appointments, the ability to make recommendations to homeowners based on usage profiles, including PPL Electric rebates / state / federal programs, push messaging, and the ability to view prior customer bills for both customers and customer service representatives using the tool.

The Company identified vendor strengths and weaknesses through the RFI process and will issue a detailed RFP to customer portal vendors as part of the smart meter program. For details on this, see Section IV. Vendor Selection for Future Technologies.

The Customer Portal assessment concluded that an upgrade to the existing system will be necessary to support regulatory and business requirements.

E. Assessments of Other Systems

In addition to the assessments discussed above, the Company also completed assessments for NOC and MAM systems.

PPL Electric began exploration of a situational awareness and real-time analytics platform for its AMI solution in 2013. The Company met with various peer utilities to discuss their approach to a NOC, which would provide those capabilities. Utilities met with included PECO, Duke Energy, and Florida Power & Light. In addition to discussions with its peers, PPL Electric also held several in depth discussions with vendors regarding their capabilities and current customers.

The Company received high-level proposals from two NOC vendors, which included a proof-of-concept approach to trial technology and determine its efficacy prior to purchasing a full system. Pricing information was also collected from these proposals and that information was included in the financial analysis for the smart meter plan, which is described in more detail in Section X. Financial Overview. The Company plans to explore a NOC proof-of-concept in or around August 2014 using its existing PLC system. The results from the proof-of-concept will be used as inputs into the NOC vendor procurement process.

PPL Electric's current asset management systems only track meters and associated communication modules internal to meters. During the AMI assessment discussed above, it was determined that a future system should be capable of tracking additional installed devices, such as network devices (i.e., routers, collectors), and have the capability to track instruments such as transformers.

In addition, an upgrade to the MAM system would allow for additional features such as software and firmware tracking. With the regulatory requirement to support over-the-air upgrades to meter hardware, additional tracking of software and firmware will be required in order to account for versions, base lining, and revision tracking as upgrades are deployed. Additionally, an upgraded MAM will provide testing beyond accuracy; the current system only accounts for standard accuracy testing and does not have the capability to store test results from additional smart meter attributes such as remote disconnect. The Company also plans to utilize the upgraded MAM to store installation test results from test performed in accordance with 52 Pa. Code § 57.20(g). The Code states the public utility shall inspect service watthour meters for proper connection, mechanical condition, and suitability of location within 90 days of installation.

F. Regulatory Compliance

PPL Electric's current PLC solution is comprised of two different vintages of meters for its residential and small commercial customers. Approximately 86% of the total meter population consists of 2002 vintage electromechanical meters with a communications module. These meters do not comply with many of the Act 129 and Implementation Order requirements. The remaining 14% consists of upgraded solid-state electronic meters, which are also unable to meet all of the requirements. A summary of the compliance of the current PLC solution versus the proposed RF Mesh is shown in Table 1.

Table 1 - Summary of Compliance of Current PLC Solution versus Proposed RF Mesh Solution

Requirement	Current PLC Solution		Proposed RF Mesh Solution
	Electro-mechanical Meters (86% of population)	Solid-State Electronic Meters (14% of population)	
1. Bidirectional data communications	✓	✓	✓
2. Reading usage data on at least an hourly basis once per day	✓	✓	✓
3. Providing customers with direct access to and use of price and consumption information	✗	✗	✓
4. Providing customers with information on their hourly consumption	✓	✓	✓
5. Enabling TOU rates and RTP programs	✓	✓	✓
6. Supporting the automatic control of the customers' electric consumption	✓	✓	✓
7. Ability to remotely disconnect and reconnect	✗	✓	✓
8. Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties, and an RTO on a daily basis, consistent with the data availability, transfer, and security standards adopted by the RTO	✗	✗	✓
9. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables	✗	✓	✓
10. Open standards and protocols that comply with nationally recognized non-proprietary standards such as IEEE 802.15.4	✗	✓	✓
11. Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible	✗	✓	✓
12. Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information	✓	✓	✓
13. Ability to remotely reprogram the meter	✗	✓	✓
14. Ability to communicate outages and restorations	✓	✓	✓
15. Ability to support net metering of customer-generators	✗	✓	✓

Throughout the technical and financial assessments detailed in the sections that follow, PPL Electric paid close attention to ensure that a new technology type will be able to meet all six of the minimum requirements set forth under Act 129 and the nine additional smart meter requirements set forth in the Commission's Implementation Order.

PPL Electric will ensure that these requirements are communicated to potential vendors as part of the vendor solicitation process, which will begin in Q3 2014. The following section provides details for each of the 15 requirements:

<u>Act 129 Requirements:</u>

1. Bidirectional data communications

The current PLC solution only allows for polling the meters and does not support proactive communications from the meters to the head end in real time. An RF solution will allow both push and pull notifications to and from meters. Additionally, an RF network will allow near-real time communications to be proactively sent by a meter to the head end and will enable last-gasp technology in the event of a loss of power to the meter.

2. Reading usage data on at least an hourly basis once per day

The current PLC solution enables this functionality by posting data to the customer web platform approximately 31-33 hours following the day, due to load constraints, data validation, and process reads. An RF solution and MDM replacement will enable the ability to record data on any scheduled interval. Data can be collected every 8 hours (or more frequently if necessary) and then processed. An upgraded MDM will also allow for continuous data processing.

3. Providing customers with direct access to and use of price and consumption information

The current PLC solution does not meet this requirement, and the Company is not aware of technology that is able to effectively provide this functionality through its PLC metering system. For RF-based communications meters, Zigbee has become the de facto industry standard, and all vendors being considered use this communications protocol to enable communications to a HAN device.

4. Providing customers with information on their hourly consumption

See (5) below.

5. Enabling TOU rates and RTP programs

The current PLC solution meets this requirement through the use of electromechanical retrofitted meters, which record hourly interval usage and demand to enable TOU and RTP billing. An RF solution would also meet this requirement. Any constraints would be consequences of back-end systems such as the CIS or MDM. Thus, an upgraded MDM system would provide additional support for this technology.

6. Supporting the automatic control of the customers' electric consumption

The current PLC solution complies with this requirement. Automatic load control is enabled by a signal on the electrical wave. Depending on the vendor solution, an RF system would allow for the same type of control through the Zigbee communications protocols or the solution's RF network.

PA PUC Implementation Order Requirements:

7. Ability to remotely disconnect and reconnect

The current PLC solution meets this requirement but requires meters with remote service switches to be installed in order to comply. The Company has completed a pilot using this technology, which is described in Section III. Technology Assessment, and subsequently has changed its standard meter to include this functionality. All RF-based solution vendors being considered comply with this requirement and have successfully demonstrated its functionality.

8. Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties, and an RTO on a daily basis, consistent with the data availability, transfer, and security standards adopted by the RTO

PPL Electric conducted a pilot in 2010 and 2011 to assess the capability to provide 15-minute interval data on a consistent basis using power line meters that have the capability to be configured for 15-minute data collection at the residential and Small Commercial and Industrial ("C&I") customer level. Currently, the Company provides sub-hourly 15-minute interval data for all its Large C&I customers. Residential customers are also provided with hourly interval data. In order to measure and record sub-hourly usage for all residential customers through the power line carrier system, the Company would need to upgrade the meters of approximately 1.2 million customers to newer electronic meters. However, the PLC system would be severely constrained in collecting the 15-minute interval data for all customers as tested in the pilot program. Furthermore, the current IT platform and systems are not built to process and store this amount of data. An RF solution would eliminate bandwidth issues associated with providing this data, while also enabling the functionality assuming that the required back office functions (e.g., an upgraded MDM system) are in place. The Company plans to deploy a solution which supports this functionality at the meter level, but will not build out the information technology platform to currently support this functionality due to cost and lack of market needs.

9. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables

The current PLC solution does not comply with this requirement as the current electromechanical retrofitted meters would have to be replaced with electronic meters. All RF-based solution vendors being considered comply with this requirement, but differ in how they approach the various standards involved. PPL Electric will evaluate RF solution capabilities in support of nationally-recognized non-proprietary standards.

10. Open standards and protocols that comply with nationally recognized non-proprietary standards such as IEEE 802.15.4

The current PLC solution does not fully comply with non-proprietary standards. The majority of meters currently installed use proprietary vendor communications standards. Only recent purchases of solid-state meters comply with ANSI C12.19 in the meter. All RF-based solution vendors being considered are compliant with non-proprietary standards.

11. Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

The characteristics of the current PLC solution make it increasingly difficult to upgrade due to restrictions with the PLC infrastructure. Furthermore, assessments and pilots conducted by the Company have revealed that it is already pushing the limits of PLC technology. An RF solution would comply with these capabilities and in some cases can provide functionality enhancements over time and as requirements evolve.

12. Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information

The current PLC solution uses electromechanical meters retrofitted with modules that calculate voltage manually, causing a potential loss in accuracy compared to more modern, electronic meters. Additionally, constraints with the current PLC infrastructure limit the frequency of voltage monitoring due to bandwidth constraints. An RF solution would include the use of electronic meters, which will allow voltage information to be reported on designated intervals and provided in a near-real-time basis.

13. Ability to remotely reprogram the meter

The current PLC solution limits support of remote programming capabilities. Some functionality changes to meter measurement and register mapping are possible, but there is no capability for meter firmware updates or major functional measurement changes. RF solutions fully support remote programming of all functions and operating system firmware and provide bandwidth availability through the communications network to enable this functionality.

14. Ability to communicate outages and restorations

The current PLC solution requires polling (pinging) the meter to obtain power status. The current solution does not allow for "last gasp" or power restoration messages to be sent proactively by the meters, so the system is unable to proactively report an outage and restoration. The current system does have the ability to poll time-stamped outage information from the electronic meters. An RF solution allows for the existing pinging capability, while also using meters which have "last gasp" and power restoration messages. These messages can allow meters to proactively report an outage and restoration.

15. Ability to support net metering of customer-generators

The current PLC solution supports net metering of customer-generators by swapping the normal retrofitted electromechanical meter with an electronic meter. An RF solution would also enable this functionality with the accompanying support of back-end systems including the CIS.

<u>Additional Requirements from the Commission's December 2012 order:</u>

1. Utilization of smart meter data for bill ready and dual billing
2. Providing at least 12 months of account or meter level historical interval usage data via EDI
3. Participation in an EDEWG working group to define a solution for providing hourly interval usage and billing quality interval usage data via a web portal
4. Providing a plan to support meter level hourly interval usage data

1. Utilization of Smart Meter Data for Bill Ready and Dual Billing

PPL Electric currently utilizes Smart Meter data for bill ready and dual billing.

2. Providing at least 12 Months of Account or Meter Level Historical Internal Usage Data Via Electronic Data Exchange

PPL Electric currently provides historical interval information at the aggregate account level via EDI and will continue to do this.

3. Participation in an EDEWG Working Group to Define a Solution for Providing Hourly Interval Usage and Billing Quality Interval Usage Data Via a Web Portal.

PPL Electric is currently participating in the EDEWG Working Group.

4. Providing a plan to support meter level hourly interval usage data

PPL Electric currently captures historical hourly or 15-minute interval usage information at the meter level. In the Company's Supplier Web Portal, this information is shown at the aggregate account level and also at the aggregate meter level. PPL Electric will continue to do this under the SMP.

IV. Vendor Selection for Future Technologies

PPL Electric will follow a staged approach to vendor selection, as shown in Figure 6. This approach has been used successfully by the Company for previous vendor selection efforts.

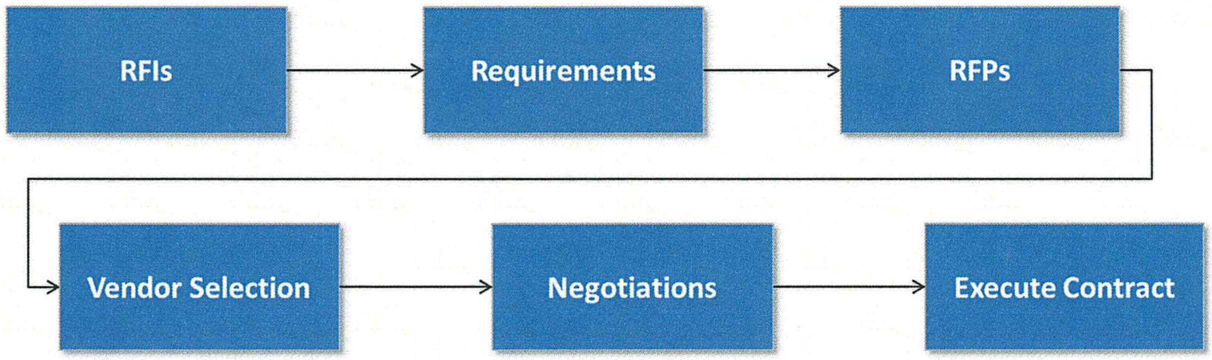


Figure 6 - Vendor Selection Process

In 2013, PPL Electric completed the RFIs stage. The RFI process and results are described in Section III. Technology Assessment. This stage included identifying smart meter technology types and evaluating strengths and weaknesses. This was followed by the creation of an RFI document, which was sent to the identified vendors. Evaluations of the responses were conducted and used as inputs into the solution decision process, which included the financial analysis.

RFIs were issued for three components of the upgraded smart meter solution: AMI Solution (including meter hardware, head end technology, and communications infrastructure), MDM, and the Customer Portal technology.

Following submission of PPL's Smart Meter Filing and this Plan, PPL Electric plans to solicit vendors for responses to a RFP for components of the smart meter solution. RFPs will be issued in two phases to capture the needed vendor support. The first phase of the issued RFPs will include:

- AMI System (including meters and head end software)
- MDM
- Customer Portal
- NOC
- Project Management Office ("PMO")
- System Integrator ("SI")
- MAM

The second phase will include:

- Deployment Vendor
- Secondary Meter Vendor

PPL Electric intends to issue detailed RFPs, which will ask vendors to comply with a series of requirements. These requirements will be divided into business, functional, and technical categories and will comprehensively describe the needed features for the AMI solution. A detailed requirements gathering phase is needed in order to ensure that the issued RFPs are comprehensive from both regulatory compliance and business need perspectives. This phase is underway and is using a workshop-based approach to meet with subject matter experts from the Company's organization and to gather system requirements from them. PPL Electric began the process of requirements gathering for the AMI Solution, MDM, Customer Portal, and NOC RFPs in May of 2014.

Following requirements gathering, the Company will create comprehensive RFP documents to issue to the vendors.

In parallel, the Company will establish scoring criteria for the RFP responses. PPL Electric will work with its internal supply chain organization and external consultants to devise a vendor scoring mechanism for the RFPs. PPL Electric plans to notify the Commission of vendor selection upon completion of that effort.

PPL Electric will select vendors using its established supplier selection methodology. This will include a detailed evaluation and scoring of the received RFP responses, evaluation of vendor pricing, requests for vendor follow-up as needed, and oral presentations. The Company may request vendors to demonstrate performance of their communications or metering hardware and software in a lab environment to aid in the selection process.

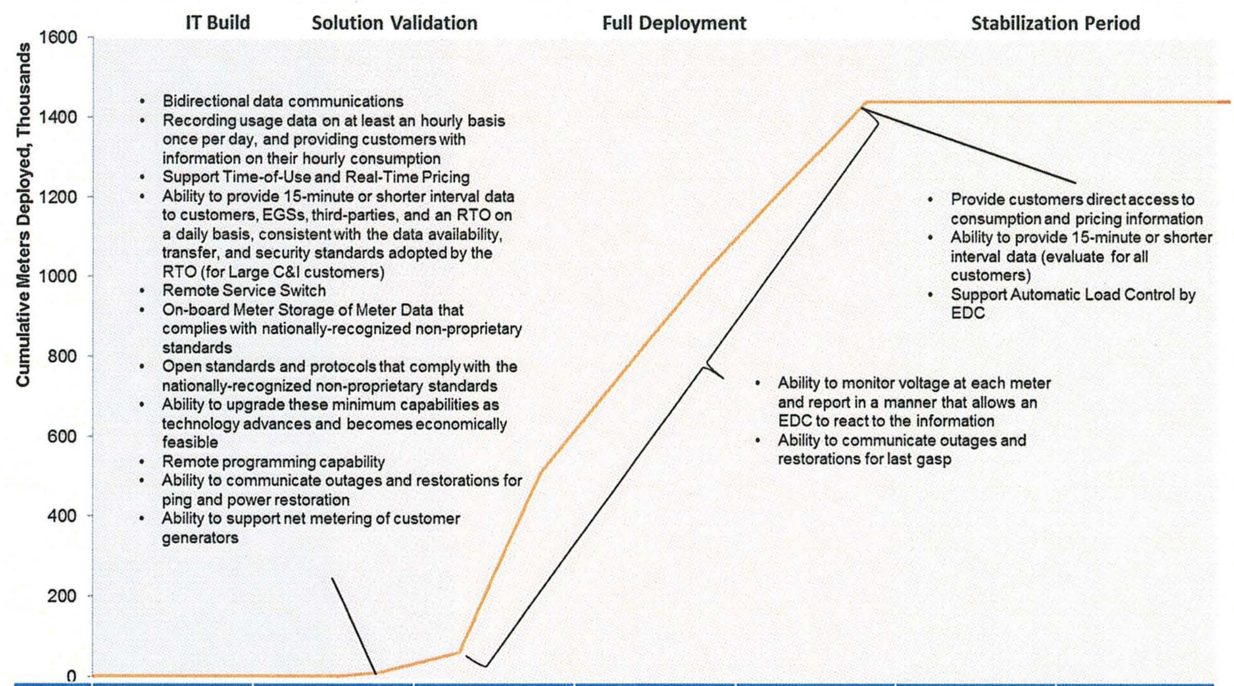
Following vendor selection, PPL Electric will hold negotiations with the vendor to agree on the terms of the contract. This process will include discussion of and consensus on terms, pricing, service level agreements, support levels, schedule execution, warranty terms, key personnel, and other topics.

Finally, responsible parties from both PPL Electric and the selected vendor's organization will execute the contract. The Company does not propose to seek Commission approval of actual vendors, but the process set forth herein. Further, the Company will not execute contracts with vendors until final approval of its SMP.

V. Implementation Plan

PPL Electric will deploy its upgraded AMI solution from 2016 – 2021. This deployment will include the building of back office IT systems, lab and field testing, a controlled solution validation phase, and a full deployment phase during which all current meters will be replaced. The deployment will be followed by a two-year stabilization period to optimize system operation. A timeline showing these steps is provided in Figure 7 - Implementation Timeline and Estimated Functionality.

Implementation Timeline and Estimated Functionality



	2015	2016	2017	2018	2019	2020	2021
Approx Meters / Year	0	10K	500K	500K	430K	0	0

Figure 7 - Implementation Timeline and Estimated Functionality

Act 129 and the Commission's Implementation Order outline 15 specific requirements to be met by smart metering systems. These requirements, and a description of how the Company's proposed solution complies with them, are detailed in Section III. Technology Assessment.

PPL Electric plans to enable this functionality in a phased approach to coincide with the components of the deployment described above. A staged approach will, in addition to reducing risk around the implementation of a new technology type, provide PPL Electric with the ability to validate components of the technology as they are deployed.

Additionally, following the end of the stabilization period in 2021, the Company will continue investigating advanced functionality beyond the 15 requirements mentioned above, including furthering analytics capabilities and identifying synergies with its distribution automation network.

A. Workstreams and Program Roadmap

To successfully establish a business and technical foundation for the new system, PPL Electric held a series of workshops in 2013 and 2014 to develop a draft program roadmap. This roadmap identifies the required teams, or workstreams, for the program, establishes a timeline of activities needed from 2014 – 2021, and recognizes interdependencies across those activities. The roadmap is shown in Figure 8 - Smart Meter Program Milestone Roadmap.

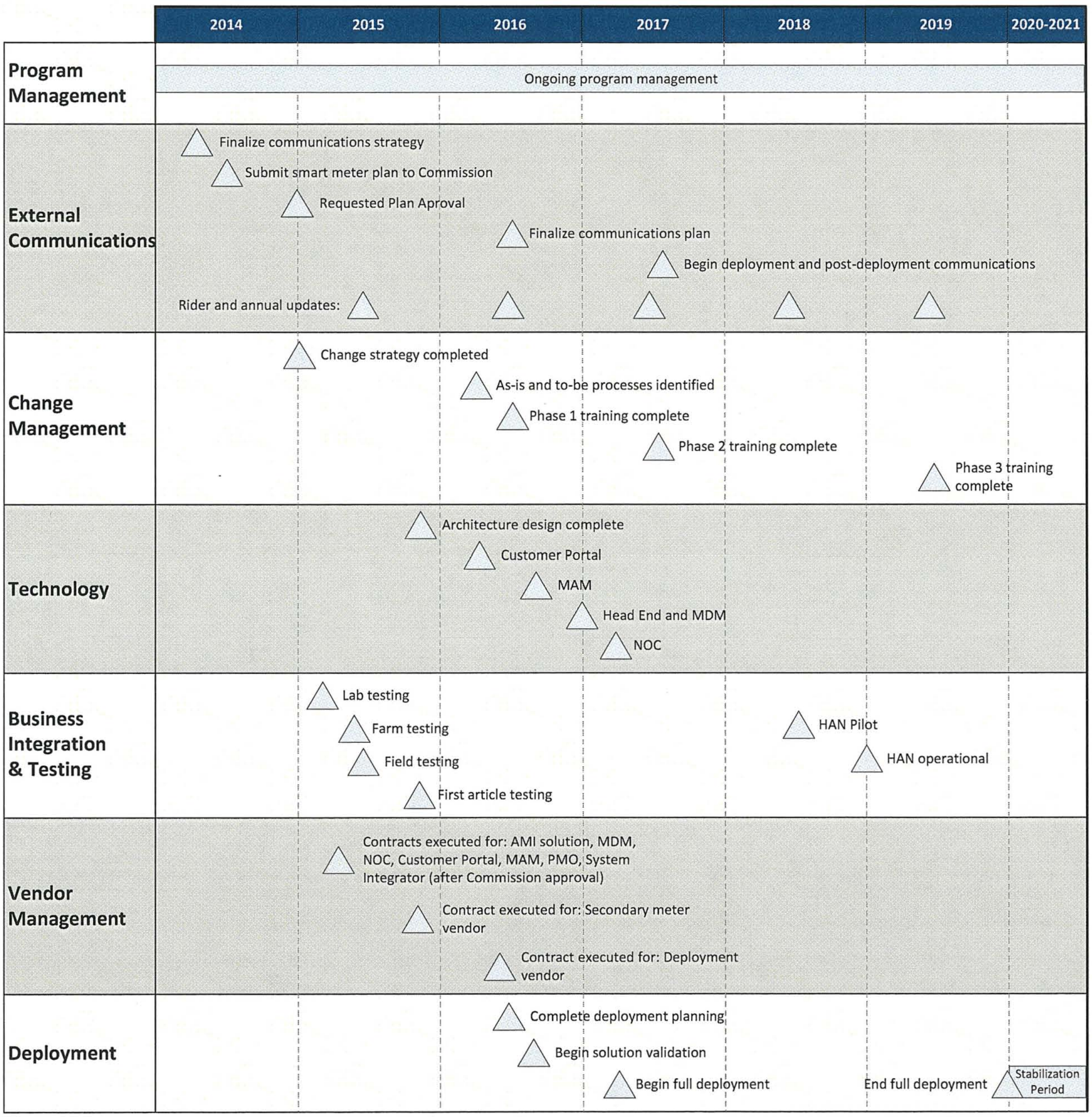


Figure 8 - Smart Meter Program Milestone Roadmap

B. Program Management Office (PMO)

The PMO will be responsible for successful completion of Smart Meter Program objectives. It will focus on program governance, planning and scheduling, financial analysis and fiscal management, and risk management.

During 2014, the PMO will be established and will be focused on establishing program governance guidelines, organizational design and staffing. Following 2014, governance will include executive sponsor meetings and weekly project meetings with workstream leaders to capture program risks, issues, and to serve as a coordination meeting for the program. PPL Electric also has established a smart meter steering committee composed of leaders around the business to provide strategic direction for the smart meter program. The PMO will have responsibility for reporting to this committee and for relaying its feedback to the workstream leaders.

Planning and scheduling is also a critical requirement for a successful deployment. The Company has to date maintained a project schedule and will continue this practice and will incorporate major roadmap activities into a multi-year project plan. This plan will be continually refined as vendors are brought on board and as project schedules change. The project plan will be used by the program management office to ensure scope, schedule, and budgets of tasks are effectively managed.

Finally, the PMO will also maintain activities related to program risk management. This will include the establishment of a risk management process aimed at tracking risk to the overall SMP program. This will include categorizing risks, assigning risk owners, and identifying mitigation strategies. It will also establish a recurring process to review these risks with the appropriate owners and business subject matter experts. This risk methodology will leverage industry-accepted processes.

C. External Communications

The External Communications workstream will be dedicated to communications activities related to the smart meter program. To support this workstream's activities, the Company has created a communications strategy (see Section XI. Communications Strategy) which describes the major communications activities related to the smart meter program which will take place through 2021.

This workstream will also be responsible for ongoing communications with customers and the Commission, preparing annual smart meter plan updates for the Commission, and for conducting regular market and peer utility research to ensure that the program is aware of the latest news and industry expertise for AMI.

D. Change Management

Change Management is defined as the set of activities for managing the impact of new technologies on the business. Its overall objective is to effectively manage integration of new technology into customer and/or business processes associated with the new technology. The Change Management workstream will have responsibility for both internal communications and the organization change management requirements which will arise due to the smart meter program. In particular, this workstream will lead internal PPL Electric efforts related to socialization of the smart meter plan and will also be responsible for identifying organizational impacts across PPL Electric's business units. Areas will include changes arising due to the addition of a Network Operating Center, new communications infrastructure, and new smart meter functionality such as remote disconnect and "last gasp" abilities.

The Change Management workstream will work to create a detailed strategy for change management in the latter half of 2014, and then will begin identifying job role impacts and be responsible for creating job aids and training materials for PPL Electric employees before the deployment period begins. This workstream will also provide ongoing support in the form of communications materials for internal discussions, presentations, and training workshops.

It is anticipated that the deployment of a new metering system will allow for improvements in current business processes and, thus, in parallel the Change Management workstream will, also manage the many business process activities that will take place through the program's life. Each stage of business process redesign will use a phased approach, beginning with identification of impacted business areas and processes, detailed workshops to decide on process redesign with impacted business units, implementation of process changes, and finally training and refinement of processes. Figure 7 - Implementation Timeline and Estimated Functionality shows this phased release approach.

E. Technology

The Technology workstream will oversee the IT aspects of the smart meter program. This will include the IT design, build, and test phases for the meters, communications network, NOC, MDM, and any other supporting technologies. This workstream is a critical component deployment planning time period; new, upgraded, IT infrastructure will be required to ensure that data captured by the RF meters is carried to the appropriate systems for billing, settlement, analytics, and other core business functionalities.

Activities in the IT workstream began with the architecture assessment conducted in 2011 (discussed in Section III. Technology Assessment) and continued through early 2014 with additional evaluation of the architecture and estimates of the timing needed for the design, build, and test phases for the smart meter program. IT activities will follow a staged functionality approach; systems will be built and released in stages over the deployment period. The sequenced rollout provides full compliance with Act 129, the Implementation Order, and PPL Electric's business requirements by 2021. This staged approach also provides a method for risk mitigation.

The timeline for IT build was determined based on the planned meter deployment schedule, which calls for 10,000 meters to be deployed in late 2016 as part of the Solution Validation (explained in additional detail below). As the purpose of the Solution Validation is to test the final versions of the IT systems and deployment tools, it is necessary that these systems be in place at that time. Consequently, the IT design and build process will begin in Q1 2015, with work progressing through September 2016 to support the Solution Validation period.

The IT system creation process will use a standard software development life cycle approach, the phases of which will include: definition, discovery, design, development, deployment, and debrief. Testing of IT systems will follow a similar approach in environments, beginning with unit testing before progressing to functional testing and then integration testing. Unit testing will test specific functionality and features, functional testing for processes around multiple features, and integration testing across systems and for testing of end-to-end functionality.

F. Business Integration and Testing

The Business Integration and Testing (BIT) workstream will manage all lab and field testing related to the smart meter program.

This workstream will begin with a planning phase for lab and field testing in late 2014, followed by design and setup of the meter lab in Q3-Q4 2015. Following this, testing activities will commence with solution testing including activities around radio frequency (RF) network design based on PPL Electric's service territory geography. Following selection of a meter hardware vendor, this workstream will focus on developing and implementing processes around first article testing, meter provision, lot acceptance testing, and other related activities. Meter and communications testing will continue through the Solution Validation phase and through Full Deployment to support first article testing and lot acceptance testing.

In addition to an enhanced IT infrastructure, the proposed AMI solution will require new capabilities in the area of meter and network communications. To date, PPL Electric's AMI solution has utilized a PLC technology. PLC allows for meter data to be sent across the existing distribution network where it is collected at the substation level by devices called collectors before being relayed to the Head End system and other appropriate back office systems. However, the proposed new solution will utilize a RF Mesh network type. In an RF Mesh network, meters communicate wirelessly with each other and with collectors located in the vicinity. These collectors then relay information over a backhaul network to the Head End system, which then "routes" the data as needed to the MDM, Customer Information System for billing, and others. PPL Electric plans to design a network to take advantage of the Company's fiber optic assets which are currently being built and expected to be available at all substations by 2016. Where collectors are able to be co-located with substations, the system will use this fiber backhaul. In areas where this is not the case, the Company plans to use a cellular backhaul system.

Due to the transitional nature of PPL Electric's deployment from a PLC to an RF technology type, the Company will be required to manage and operate dual systems throughout the deployment period. Meter and communication infrastructure for PLC will be maintained so long as it is required in a given geographic area, and technology will be transitioned to RF as those meters and systems are deployed. In the same vein, PLC meters which fail prior to the scheduled RF upgrade will be replaced with PLC meters, until the infrastructure to support RF meters become available in that geography.

PPL Electric will also test the communications network and determine an optimal network design. Much of this information will be leveraged by the chosen vendor for the AMI Solution, who will be able to provide tools for network design and data flow optimization to aid in the establishment of a robust communications network. Optimization of the network will also leverage industry best practices observed from currently-operating RF AMI systems at peer utilities, and subject matter expertise from PPL Electric's organization.

Lab testing will focus on several key testing types:

- Component Testing – Will verify that components meet functional, technical, and business specifications and criteria
- Functional Testing – Will verify that the smart meter solution (including meter and communications network) meet functional, technical, and business specifications and criteria
- Integration Testing – Will verify that criteria are met across systems and applications, e.g., from meter communications network into PPL Electric's back office systems (Head End, Meter Data Management)
- Communication Testing – Will verify end to end communications
- Security Testing – Will verify security protocols and procedures, and compliance with standards and PPL Electric's security requirements

PPL Electric also has developed a strategy to address in-service and removed watthour meter testing during full deployment in years 2017 to 2019. In regard to in-service periodic testing of watthour meters, the Company will appropriately adopt its current sample process to ensure that in-service testing continues to meet or exceed the requirements contained in 52 Pa. Code § 57.20(e).

In regard to testing removed watthour meters during full deployment, the Commission's Implementation Order exempted all electric distribution companies required to install smart meter technology from compliance with 52 Pa. Code § 57.20(h), which states, "A service watthour meter which is removed from service shall be tested for "as found" registration accuracy." Nevertheless, the Company will implement a "Deployment Sample Process" to identify a statistically significant random sample of removed meters. This sample of removed meters will be flagged for registration accuracy testing and returned to the Company's meter test lab as they are removed from service by the deployment vendor.

In addition, PPL Electric will hold all removed meters for two billing cycles before allowing them to be retired. This will allow any customer billing concerns to be addressed and provide the ability to locate the stored meter for accuracy testing.

G. Vendor Management

This workstream will have management of all vendor-related activities. A detailed description of the vendor needs is provided in Section IV. Vendor Selection for Future Technologies.

This workstream began work in May 2014 with a detailed requirements gathering phase for the first set of vendors, which include the AMI Solution (Meter hardware, Head End technology, communications technology), MDM, NOC, and Customer Portal vendors.

Work will continue through 2014, with an expected vendor selection by Q1 2015 to align with the expected Commission approval of this filing. Simultaneously, the workstream will begin work on selection of vendors for the PMO, System Integration, and a secondary meter hardware vendor. It is expected that this second set of vendors will be selected by Q2 2015. Additionally, a deployment vendor will be solicited in Q4 2015 with selection at the end of Q1 2016.

Once vendors are chosen, this workstream will have all responsibility for the day-to-day management of vendor related processes. This will include onboarding and offboarding of vendor personnel, processing of vendor invoices, and management of vendor contracts and change requests. The Vendor Management workstream will also serve as a point of contact for vendors regarding issue escalation to the program.

PPL Electric plans to utilize industry best practices for the vendor solicitation and management processes and will leverage its internal supply chain and procurement organization to templates and guidelines for vendors in the SMP.

H. Solution Validation Phase

Deployment of meters will begin with a "Solution Validation" phase, which will start in late 2016 and will include a total deployment of up to 50,000 meters. The purpose of the Solution Validation phase will be to use the processes and tools planned for full deployment with a limited meter population and slower deployment rate. Limiting the meter population and deployment rate will allow for fine tuning of the metering and communications network following the field testing described above.

PPL Electric will develop a strategy for the Solution Validation phase which will identify specific aspects of the deployment plan to be optimized. These will include geographic area deployment plans, cross-dock and warehousing strategy, use of deployment vendor field tools, work management process optimization, safety program compliance, hard-to-access customer processes, and other aspects of the deployment. Each of the identified optimization areas will be measured as appropriate, and the Company will ensure that the Solution Validation phase results are successful before commencing with Full Deployment. This phase will also include testing of business processes such as billing, remote disconnect functionality, and others.

I. Full Deployment

Full Deployment will begin in 2017 following the Solution Validation phase and will continue through 2019. To fully deploy the remaining approximately 1.4 million meters in the PPL Electric service territory, it will require an average deployment rate of around 2,000 meters/day. Network and communications infrastructure (collectors, backhaul equipment) will be deployed ahead of meter hardware. This will allow for newly-installed meters to become operational on an existing communications network and will mitigate potential communications issues.

Processes for deployment will rely on the tools offered by the chosen deployment vendor, industry best practices and PPL Electric's experience with previous large projects of this nature. To aid in this, the Company plans to create a detailed deployment plan which will address all major components of the deployment. This will include:

- Deployment Vendor Contracting Strategy – Processes for development, execution, and management of deployment vendor contract. This will include strategy for managing vendor terms and accountability structures in the contract, as appropriate.
- Geographic Deployment Plan and Sector Selection – Location-based deployment plan for meter deployment across the PPL Electric service territory. This will also align geographies to timing of deployment during the Solution Validation and Full Deployment phases.
- Regional Readiness and Transition – Pre-deployment strategy at the district level to ensure preparedness for incoming deployment.

- Sector Acceptance Criteria – Checklist for activities required prior to approving deployment in a particular sector, i.e. certain level of read rates, mitigation of all communication issues, etc. This effort will include strategy for handoff of the solution on a sector-by-sector basis from the deployment team to PPL Electric operations.
- Supply Chain and Logistics – Procurement strategy and logistics, including strategies for location of cross-docks and warehouses, mobile project management requirements, and movement of hardware across the PPL Electric service territory.
- Workforce Management Strategy – Management of deployment contractors and personnel, including badging, training, on- and off-boarding, and safety procedures.
- Risk Identification and Mitigation Strategy – Strategy to manage risk associated specifically with the deployment project. This will be closely tied to the Program Risk management process mentioned above, but will focus on the deployment.
- Communications Network & Meter Installation Strategy – Strategy for installation of network and meter communications network. This will use the network design mentioned above to develop an optimal timing for installation of the communications infrastructure.
- Safety Plan – Plan describing safety policies and procedures required by all deployment personnel in alignment with PPL Electric's existing safety requirements.

PPL Electric intends to create this detailed plan beginning in 2015 and will communicate its details with the Commission as it is finalized.

J. Stabilization Period

Following the completion of deployment in 2019, the system will enter a two-year stabilization period (through 2021). This stabilization period will continue the process of fine-tuning the mesh network and back office systems. This time period will also be used to deploy any final system enhancements or upgrades prior to full operationalization in 2022.

During the deployment time period, PPL Electric will simultaneously operate the systems needed to support the upgraded system as described above, and will continue to operate current PLC systems. Meters and communications will be "cut over" from the PLC network to the RF network based on a cutover process which will be developed by the Company as part of the deployment planning process. The Stabilization Period will act as the final cutover from PLC to RF, and will serve as the time period during which any PLC-related systems no longer needed to support the RF AMI solution will be decommissioned.

This time period will also be used for refinement of business processes changes which were implemented throughout the deployment project. Additionally, PPL Electric recognizes that there may be some meters in hard to access locations or challenged radio frequency environments – where an RF signal may not propagate well due to geographical or other constraints. The Stabilization Period will address installations of these meters.

K. Post Grace Period Customer Requests and New Construction

PPL Electric is proposing to continue to install its existing PLC meters for customer requests and new construction in each geographic region of its service territory until it has extended the RF Mesh network to that geographic location. Thereafter, PPL Electric will install RF Mesh meters for customer requests and new construction in the geographic location. If PPL Electric were to install RF Mesh meters in a geographic location before the appropriate communications systems are in place, it would have no way to read the RF Mesh meters in these areas. PPL Electric believes that this approach is reasonable for several reasons, including:

- PPL Electric is unique in that it already has an AMI solution that delivers some of the customer benefits required by Act 129 and the Commission's Implementation Order. For example, customers already benefit by having access to hourly energy usage information, receive very few estimated bills due to the high meter reading performance of the existing system, and have meters that support net generation.
- The number of new construction customers that may be impacted is estimated at an average of 7,200 per year based on historical growth. The Company does not expect a significant number of customers to request a smart meter in advance of their scheduled deployment. The total number of potentially impacted customers over the life of the deployment (2014 – 2019) is estimated at 40,000.
- The Company is proposing to deploy an RF Mesh AMI solution and will be doing so based on geographic area, which will be the most efficient use of resources for deployment. New construction customers within geographic areas where RF Mesh network coverage exists will receive RF Mesh smart meters. Those customers that are outside of the geographic deployment area would receive an advanced PLC meter which would be changed during the normal deployment process, expected to be completed by 2019.
- PPL Electric already has a fully automated metering system and no longer has manual meter readers. As a result, the Company would still need to read those meters installed during the Post Grace Period. It would be imprudent, costly and resource intensive to develop micro RF networks to read these meters. Likewise, it would be imprudent and resource intensive to develop manual meter reading processes for a small number of customers.

VI. Cybersecurity and Data Privacy

A. Background

PPL Electric maintains a strong commitment to cyber security and data privacy, continually investing through its people, processes and technology. PPL Electric recognizes that in order to mitigate today's, and anticipate tomorrow's cyber risks and threats, we must maintain and enhance a "defense in depth" cyber security plan. Our cyber security strategy must encompass the wide range of assets and environments vital to support critical infrastructure and vital business functions, such as Smart Meters.

1. People

PPL Electric maintains an cyber security focused workgroup (Information Assurance Group – IAG), comprised of individuals who are trained, certified and experienced in information and cyber security. Investment in, and ongoing assessment of our cyber skills is vital to the success of our cyber security function. PPL Electric's employees work with business and IT partners to implement and monitor the necessary layers of cyber defenses. Our personnel hold and maintain several IT industry standard security certifications, and actively pursue additional relevant intelligence and training. Several team members hold federal security "Secret" level clearances, and actively participate in security forums, peer sharing groups, vendor partnerships, industry organizations, and state and federal avenues for information and intelligence sharing. This level of engagement and skills development enables the team to keep up with emerging threats, defenses design, and evolving technologies, such as with technologies that support Smart Meters and RF Mesh architectures. PPL Electric also contracts as needed with experienced cyber security consulting firms, or engages objective assessors to perform security skills, design, and operational assessments, and includes evaluations of our program compared to cyber security frameworks. As a Company with assets across the US and in the United Kingdom, we also can draw upon expertise and knowledge from colleagues in Kentucky and the UK.

2. Process

PPL Electric personnel leverage internal security policies, standards methodologies, and procedures. These internal elements are derived from security best practices from a variety of proven sources, congruent with the relevant security requirements and nature of the assets/information to be protected, such as Smart Meters. For example, the Company's cyber security program is not only well rooted in the National Institute of Standards and Technology (NIST) security standards, but also has benefited from ongoing assessments against other mainstream cyber security frameworks. With the recent release of a new NIST cyber security framework, and the increased presence of Department of Energy's Cybersecurity Capability Maturity Model, PPL Electric continues to look to best practice guidance for novel and effective ways to protect the company's assets from current and emerging threats.

3. Technology

PPL Electric has a strong commitment to investing in cyber security technology to support its defenses in depth. Along with the technology investments such as Smart Meters that enable enhancements in areas such as improved reliability, customer satisfaction, communications, and mobility, PPL Electric's cyber defenses must keep pace. With the qualified staff in place, who develop and follow strong and proven processes aligned to best practices, the functional and security technology can work together to provide secure results.

B. Purpose

This section serves as an introductory outline of the cyber security plan to address cyber security threats and vulnerabilities with respect to data confidentiality, availability, and integrity for the proposed smart meter plan.

When evaluating the risk and possible repercussions of a cybersecurity event, PPL Electric will consider not only the potential impact to the flow of power to customers, but also the intended flow of data through the Company's system(s). Security and privacy recommendations will be designed to provide an acceptable level of protection for the continued confidentiality, integrity, and availability of the data that is stored, processed, and transmitted through the system, as well as PPL Electric's continued ability to control the flow of power to customers.

The likelihood that any potential adversary will attack PPL Electric's Advanced Metering Infrastructure (AMI) is dependent upon three general areas; desire to attack the system, the capability to conduct an attack, and the opportunity to attack. The desire to attack is based on the overall system awareness of the attacker and the perceived value of the information stored, processed, or transmitted over the Company's data paths. If a potential attacker determines that the value of the data warrants an attack, they must develop the capability to launch an attack. Finally, even with desire and capability, the attacker must be presented with the opportunity to launch an attack. PPL Electric will undertake efforts to limit the capability and opportunity of potential attackers. Completion of a comprehensive Security Architecture Review will identify the current security risks to AMI, and a specific set of recommendations will be developed that, when implemented, will directly affect the opportunity and limit the capability of an attacker. The approaches identified in this document further enhance the protection provided to the AMI system. Development and implementation of the smart meter plan's specific policies and procedures, along with application of the hardware configurations to be recommended as part of the cyber security design, represent a holistic approach to cyber security that will enable PPL Electric to make informed cyber security and data privacy decisions for the smart meter plan as standards, guidance, and policies continue to evolve.

C. Organizational Commitment

PPL Electric has company-wide operating processes in place to ensure reliability and a robust security environment which will be used for the Smart Meter Project. The Company will utilize an integrated project team approach that will be led by PPL Electric Utilities, which has the ultimate responsibility for the reliability of the Advance Meter Infrastructure (AMI) system. Figure 9 identifies the relevant internal organizations and a list, albeit not exhaustive, of their responsibilities with respect to AMI cyber security.

Responsible Organization	Responsibilities
PPL Electric Utilities	• Primary responsibility for secure, reliable operation of the AMI System including security of the smart meters • Total system and security responsibility and accountability • Disaster Recovery and Business Continuity Planning • Asset Identification and Management
Human Resources/ Corporate Security	Personnel: • Screening, qualification, and requalification • Background Checks • Training • Access Control • Physical Security requirements
Information Assurance Group	• Data Loss Prevention • Anti-Malware Management • Perimeter & Remote Access Protections • Encryption • Logical Access Controls/Identity Management • Password Management • Intrusion Detection • Incident Detection • Vulnerability Scanning & Remediation • Penetration Testing/Security Risk Assessment • Secure Code Reviews • System Hardening • Distributed Denial of Service (DDoS) protections • Disaster Recovery and Business Continuity Planning • Security Education, Awareness and Training • Security Patch Management • Cyber Security Incident Response • Vendor Security Assessment • Other focus areas identified as needed

Figure 9 - Organization Cyber Security Responsibilities

D. Approach to Cyber Security

To ensure cyber security risks are adequately addressed, PPL Electric will utilize its project management methodology to aid in creating cyber security controls, processes and procedures. This process is a risk management-based approach for identifying, quantifying, and mitigating risks throughout a project's lifecycle. This approach enables the Company to understand and manage the threats and risks in its current operations, as well as to identify potential future risks and develop appropriate mitigation plans. The manner in which the cyber security and data privacy components of this project integrate with the project lifecycle process is included in Figure 10.

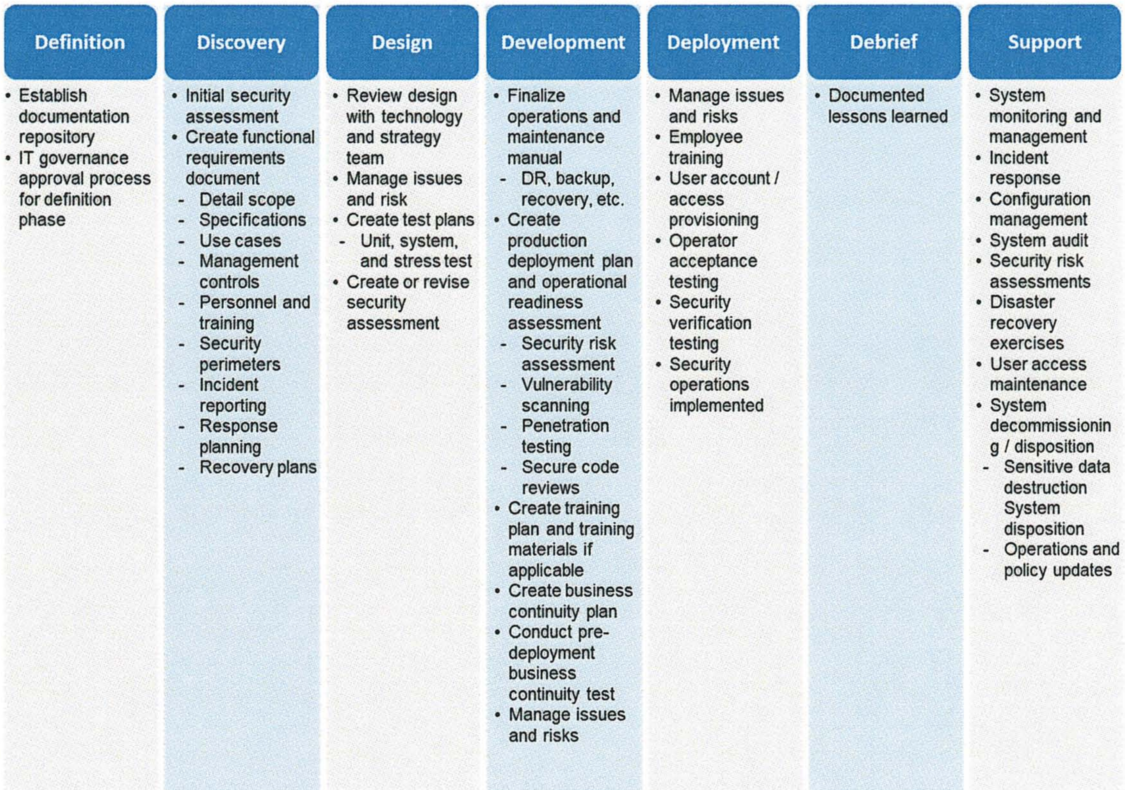


Figure 10 - PPL Project Management Methodology Process

E. Vendor Cyber Security Requirements Assessment

AMI System equipment provided by third party vendors will be evaluated for compliance with Cyber Security Requirements derived from PPL Information Security Standards and appropriate industry security standards and frameworks. This evaluation process will continue throughout the development lifecycle, and is outlined in Figure 11 below.

Review Proposed Hardware

- Evaluate Hardware for Applicability to the Defined Requirements
- If Applicable, Evaluate Hardware Capability for Compliance with Requirements
- Identify Any Hardware Requirement Deficiencies

Hardware Recommendations

- Evaluate Hardware Deficiencies and Identify Possible Mitigating Factors
- Rate Hardware Requirements Compliance as 'Compliant Out of the Box', 'Mitigations Required for Compliance' or 'Non-Compliant, No Mitigations Possible'
- Identify if Alternative Hardware Solutions are Needed
- Develop Recommended Actions for Consideration Prior to Implementation

Figure 11 - Vendor Cyber Security Requirements Assessment

Any changes to the hardware solutions planned will be evaluated via this process, and recommendations will be presented prior to implementation. In the event that a component cannot meet the Cyber Security Requirements, PPL Electric will evaluate the risk and its mitigation options as part of the Security Risk Assessment process.

F. Cyber Security Operations

The project management methodology extends to operational support of the cyber security environment. To that end, the smart meter program will implement monitoring, logging, and incident reporting. PPL Electric plans to implement intrusion detection systems and processes to provide alarming and notification of security events. Additionally, the Company's Computer Security Incident Response Team (CSIRT) will utilize existing tools, capabilities, and procedures to provide timely response and recovery from security incidents. Upon notification that a security incident may have occurred, or is likely to occur, an alert is sent to the Information Assurance Group (IAG). IAG assesses the incident and, if necessary, assembles a CSIR Team comprised of subject matter experts relevant to the specifics of the incident. The response team prepares an action plan, mitigates the security incident, and assembles documentation in accordance with PPL Electric incident response procedures. These procedures will be reviewed and updated, if necessary, during the AMI cyber security design process. PPL Electric currently has in place policies and procedures for managing user access, performing system audits, reviewing system logs, etc. to maintain cyber security vigilance. These policies and procedures will be augmented, if need be, to address any new or unique risks or issues associated with AMI. In addition, updates and patches to infrastructure devices and systems will be managed using the existing Configuration and Change Management Standard. This standard requires that major upgrades and patches must include a security risk assessment prior to operational implementation.

PPL Electric has in place both Disaster Recovery (DR) and Business Continuity (BC) plans that are regularly tested by means of DR and BC drills. These plans will be updated to encompass the

AMI systems, and DR and BC drills will be conducted as part of operational readiness testing to verify plan effectiveness.

G. Risk Assessment, Testing, and Quality Assurance

In addition to the project management methodology, the Smart Meter Project will create a Risks Register document, and any cyber security or data privacy related risks will be entered and managed accordingly.

Test plans will be developed and executed to ensure that cyber security functions operate as designed. Figure 12 below depicts PPL Electric's approach to system security testing.

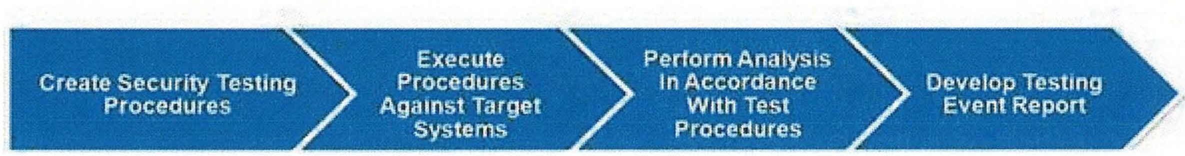


Figure 12 - System Security Testing Process

IAG will be responsible for identifying and mitigating security risks and ensuring that the fielded systems meet the requirements and configuration as prescribed in PPL Electric Information Security Standards, and include the following activities:

Security Risk Assessments

The Security Risk Assessment ("SRA") is a review that provides a baseline for the development of risk mitigation actions needed to protect the utility's systems and environments. It is conducted using a well-defined set of information security standards, guidelines, and industry best-practices. The SRA activities will include: 1) System characterization (both operational and technical), 2) Threat identification, 3) Vulnerability identification, and 4) Risk Determination/Valuation.

Using the guidelines provided by Federal Information Processing Standards ("FIPS") and NIST among others, the Security Risk Assessment will determine the potential impact of threats and vulnerabilities to the Confidentiality, Integrity and Availability ("CIA") of the project's data and systems. This impact determination, combined with an assessment of threat probability, will form the basis for risk-weighted mitigation planning.

Vulnerability Scans

Vulnerability scans are conducted on the operational system, prior to deployment and post-deployment, to ensure the system adheres to the cyber security design. This quality assurance check is conducted using automated tools and manual scanning to verify configuration items such as: firewall rules, port configurations, password structure and complexity, user authentication and access permissions, etc.

Penetration Testing

Penetration testing is the best indicator of real-world vulnerability to cyber-attacks, both internal and external. Conducted by objective, experienced and knowledgeable "Certified Ethical

Hackers," this activity determines the degree to which the systems are vulnerable to a variety of cyber-attacks. The team will conduct a series of targeted attacks from the smart meters to the AMI systems and document the gaps and vulnerabilities discovered. These gaps and vulnerabilities will be managed and/or mitigated by the project team.

H. Data Privacy

As part of the project management methodology, one of the first steps of the initial security assessment is to determine the type of data so that the appropriate security controls are planned for. For the Smart Meter Project, IAG will also follow "Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and the Smart Grid" recommendation sand conduct a privacy impact assessment (PIA) before any deployment. The PIA will help the project team with the following:

Identifying and managing privacy risks: Conducting an exercise to identify potential privacy risks early in the project demonstrates good governance and business practice.

Avoid unnecessary costs: By undertaking an assessment early in the project to identify potential privacy risks, it will allow the project team to consider any safeguards as part of the project budget and thereby avoids unexpected costs after deployment.

Meeting legal requirements: Conducting the assessment provides the opportunity to ensure that any privacy risks are identified early, and thereby implementing the appropriate controls that will allow for ensuring the implementation adheres to legal requirements. This also applies when engaging a third party, where the data owner is responsible for ensuring the appropriate controls are in place to protect personal data.

I. Standards

As noted, the Smart Meter Project will leverage emerging interoperability and security standards, including, but not exclusive to those developed by the NIST.

Throughout the Smart Meter Project lifecycle, security requirements, processes and procedures will leverage the following standards:

Security Requirements Creation	NIST SP 800-53 "*Recommended Security Controls for Federal Information Systems and Organizations*"
Security Risk Assessment Methodology	NIST SP 800-30 "*Risk Management Guide for Information Technology Systems*", NIST SP 800-60 "*Guide for Mapping Types of Information and Information Systems to Security Categories*", and FIPS 199 "*Standards for Security Categorization of Federal Information and Information Systems*"

Vulnerability Identification	NISTIR 7628 "*Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and Smart Grid*"
Security Testing Methodology	NIST SP 800-115 "*Technical Guide to Information Security Testing and Assessment*"

J. Impact on Overall AMI Security

Protection of AMI is accomplished via multiple layers of network, personnel, and physical security barriers. If compromises to the system were to occur, the location of that compromise would determine the impact on the overall AMI security. While there are numerous endpoint devices in the AMI network, compromise of one device would have a lower overall impact than a compromise of the AMI Systems. These levels of compromise are represented in Figure 13, with red representing the highest potential impact.

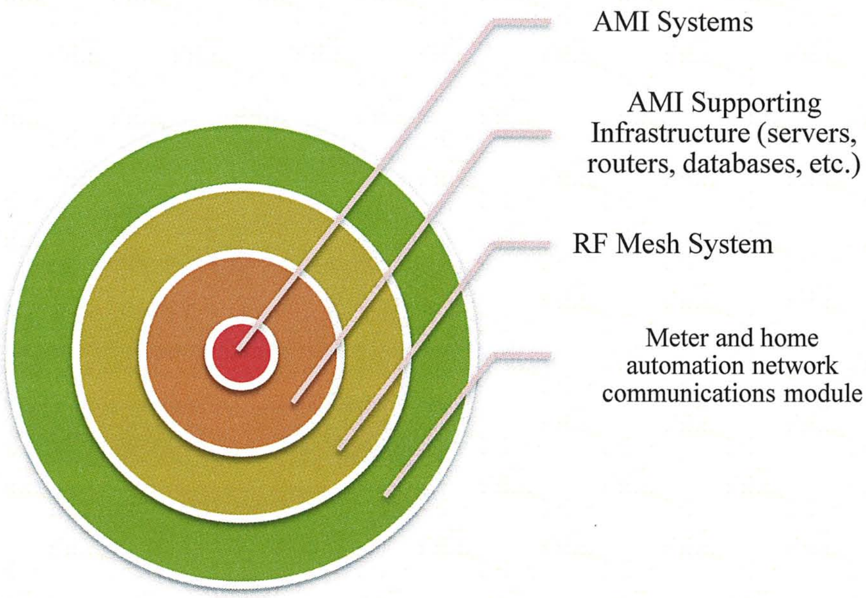


Figure 13 - Potential Impact to Overall Grid Security

The smart meter plan will be implemented with Cyber Security and Data Privacy as a cornerstone of the project. The increased scrutiny of the AMI systems and network, the interfaces with new smart devices, and reviews and updates to existing policies, procedures, and operational concepts is expected to maintain the overall security posture of AMI.

VII. Organizational Impacts

PPL Electric recognizes that the proposed AMI solution upgrade from a PLC-based to an RF Mesh system will require organizational change. During its initial deployment in 2002, the Company developed an organizational impact plan and has begun the process of doing the same for the new deployment in 2016.

In 2013, the Company undertook an organizational assessment to evaluate the impact of the upgraded AMI solution on the organization. This assessment was divided into three areas:

- Change Impact Analysis – evaluation of areas of anticipated business change and the subsequent impacts, if any, to PPL Electric
- Governance Method – method for leadership and accountability organizations for the smart meter program implementation
- High-Level Resource Plan – resource count estimates based on the above in order to determine needs for the smart meter program

A. Change Impact Analysis

The change impact analysis began with identification of the implications associated with each evaluated solution offering. This was done in tandem with the Technical Assessment (see Section III. Technology Assessment), and used information provided by vendors and through subject matter expertise from IBM and others. This was used to gather high-level costs of the various technology types (RF Mesh, Point to Point, Power Line Carrier) from an organizational point of view.

Following this, the Company identified business units within PPL Electric's organization that will likely be affected by the transition to an upgraded AMI system. For each process area, impacts were determined and categorized according to people, processes, technology, and organization. The result was an organizational impact analysis which documented expected changes to the organization due to smart meter program activities.

Based on this framework, the Company first identified organizational impacts that would be present regardless of the chosen solution type. Information from vendor RFI responses allowed the Company to identify technology-specific organization impacts, taking into account the unique differences between Power Line Carrier (PLC), Radio Frequency Mesh (RF Mesh), and Point-to-Point (P2P) network types. For example, both RF Mesh and P2P networks topologies require skilled RF technicians for system maintenance, which represents a new skill set for PPL Electric's organization.

Following the submission of this filing in 2014, PPL Electric will continue this assessment and begin planning for the creation of training materials and training as part of a larger change management effort. This is described in detail in Section V. Implementation Plan).

B. Governance Method

The Organizational Assessment also included a review of governance models typical of large AMI deployment projects. In this review PPL Electric re-evaluated its governance structure during its first AMI deployment and reviewed industry best practices around AMI governance provided by IBM and peer utilities. An initial governance structure for the Project Management Office (PMO) was created, and this will continue to be refined as requirements for vendor support are created in the coming months. A picture of the proposed governance structure is shown in Figure 14.

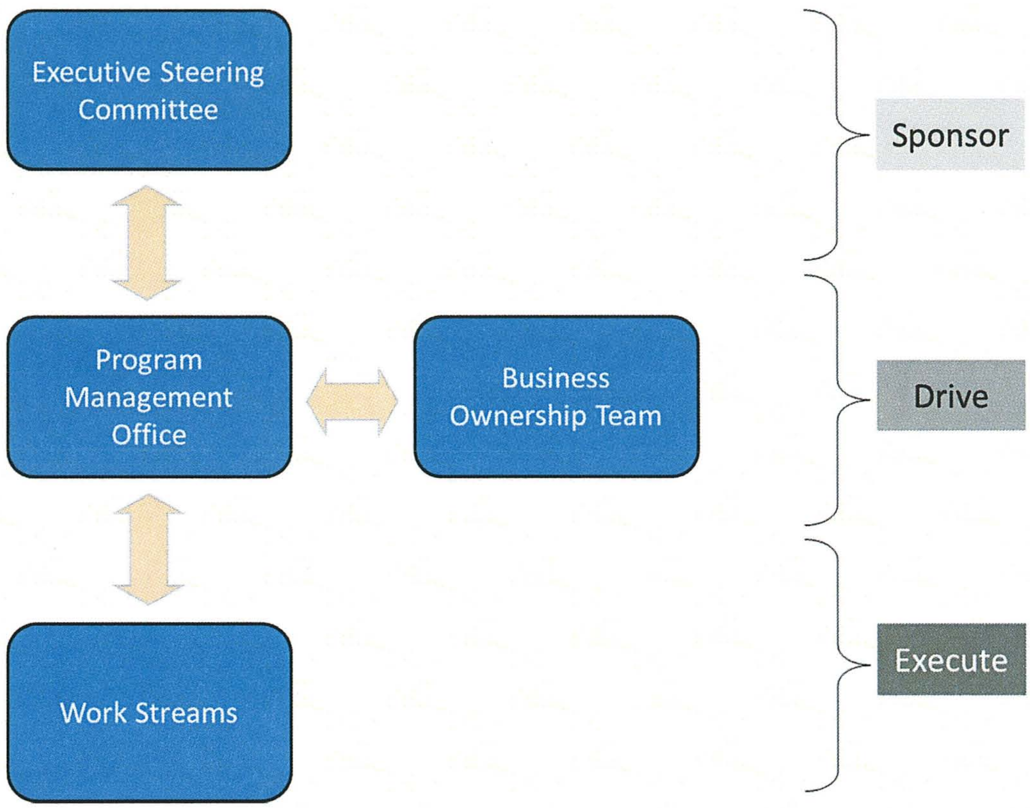


Figure 14 - Proposed Smart Meter Program Governance Model

Executive Steering Committee

The Executive Steering Committee will be responsible for providing strategic direction, issue resolution, and making program-level decisions. This group will also champion the program's budget and resource request within PPL Electric's business, and enable cross-business lines of communication as appropriate. This committee will also provide sponsorship and leadership for the SMP program.

Program Management Office

The Program Management Office will manage SMP program resources and provide day-to-day management and oversight of the SMP program. This will include oversight of the workplan and coordination of program risks, issues, and status updates. This group will also be responsible for communicating SMP program vision, goals, and strategic priorities to team members and will escalate issues coming out of the program as necessary.

Business Ownership Team

The Business Ownership Team will have ownership of the SMP program. This will include participation and expertise into SMP program decisions as they impact ongoing and future business operations. This group will also ensure availability and involvement of required subject matter experts and will communicate decisions made at the business unit level which will affect the SMP program. This team will be accountable for conflict management and will provide input and guidance into the risk mitigation and issue resolution process.

Workstreams

Workstreams will be responsible for the execution of SMP program workplan tasks, work products, and deliverables. These groups will communicate program status and budget requirements to program management, and maintain workstream-specific issues, risks, and mitigations plans.

C. High-Level Resource Plan

The final stage of the Organizational Assessment was the creation of a High-Level Resource Plan. The information from the analysis described above was used to create estimates of resources needed to support the pre-deployment, deployment, and post-deployment activities. The Company prepared representative ranges of head counts as related to job role from industry data collected from peer utilities' programs.

These estimates were refined as the decision to proceed with an RF Mesh solution was made, and will continue to be refined leading up to the deployment time period. The Company also plans to request that vendors provide detail around head counts required to operate their systems as part of the RFP process which will take place in Q3 – Q4 2014. This detail will be used in refining head count estimates. A detailed description of that process is in Section IV. Vendor Selection for Future Technologies.

VIII. Program Risks

A. Risks

PPL Electric's Smart Meter Plan represents a significant investment which is spread across several years. The Company recognizes that the SMP will impact many key stakeholders, both internal and external, and that an upgraded AMI solution brings with it the need for a comprehensive risk assessment and management process. As such, the Company has identified several program-wide risks based on their possible impact to the program and PPL Electric's business. These risks are described in detail below, followed by an explanation of mitigation steps being taken to address them.

- New regulatory or legislative requirements
- Resource availability and skill sets
- Customer perception and education
- Vendor performance
- Technology obsolescence
- Complexity of IT efforts
- Replacement of mature AMI systems and data migration

New regulatory or legislative requirements

A risk exists around unanticipated requests related to smart meter technology by regulatory or legislative bodies. Depending on their nature these may alter the schedule, scope, or budget of PPL Electric's Smart Meter Plan. Examples include the requirement to allow customer to opt-out of advanced metering functionality, accelerated supplier switch, changes in required smart meter functionality, and implementation of new legislation and / or regulation related to smart metering and energy efficiency, and additional changes in technology standards.

Resource availability and skill sets

A risk exists around availability of skilled resources needed for PPL Electric to successfully complete the work required prior to and during the new smart meter deployment. The selection of an RF communications type will bring with it the need for new skillsets to PPL Electric's business. Additionally, a large number of resources will be needed from vendors and the Company in order to guarantee the success of the SMP. The Company will need to assess these risks and develop resource plans using employees and contractors to mitigate the risk.

Additionally, PPL Electric will continue to operate the installed PLC communications system, MDMS, MAM and customer portal as required through the plan implementation. The Company plans to maintain the current level of service to customers served by the legacy systems. Resources will be required to operate the existing systems through plan implementation. This resource need is considered in PPL Electric's resource planning process.

Customer perception and education

PPL Electric's customers have experienced many of the benefits of the required smart meter technology since 2004, when PPL Electric completed its first AMI deployment. The choice to proceed with an RF communications technology results in the need for some additional education for PPL Electric's customers on this new technology type. Additionally, the upgraded

AMI solution will bring some new smart meter functionality to customers. The Company will ensure that customers receive appropriate communications on the new smart meter functionality as it is deployed.

Vendor Performance

A risk exists around ensuring that the vendors chosen to support the AMI solution provide adequate hardware, software, and services, and that performance in these areas is commensurate with the expectations of the Company. There is additional risk created around the integration of vendor systems with one another, in particular as related to vendor-provided software for disparate components of the solution.

Technology Obsolescence

There is a risk that elements of the chosen technology type may become obsolete during the course of the smart meter program. Multiple types of technologies for AMI exist in the marketplace today, and this technology is within a highly evolving area which has experienced significant change over the last 10 years. It is likely that these changes will continue in the years to come.

Complexity of IT efforts

The upgraded AMI solution involves a large-scale IT project to support the various back-office systems needed to ensure successful operation. Multiple corporate systems, some not specifically related to smart metering, will be affected by the AMI solution upgrade. This includes the installation of new vendor-purchased systems, the creation of integration points to existing systems, and the data conversion needed to enable successful communications across systems. This will require a comprehensive rebuilding of the current IT architecture across PPL Electric and several testing and release cycles prior to system optimization.

Replacement of mature AMI systems and data migration

In addition to the effort required to implement the RF Mesh AMI solution, there will be IT complexity due to the simultaneous operation of both the PLC and RF Mesh solutions as the Company transitions from the former to the latter. This transition brings unique challenges to the Company, including the migration of customer data from existing systems to new ones, the development of processes for operating of multiple AMI solutions simultaneously, and the maintaining of high meter read rates throughout the deployment time period.

Furthermore, PPL Electric is unique among its peers by being one of the first utilities to encounter this challenge, as many other utilities have not yet upgraded from one AMI solution to another. As a result, the Company expects limited benchmarking and industry experience with this effort.

B. Mitigations

To mitigate risk throughout the duration of the Smart Meter Plan, PPL Electric will do the following:

- Conduct ongoing risk management and mitigation
- Participate in site visits with vendors and peer utilities

- Engage industry expertise and external program support
- Deploy a flexible AMI solution
- Strategic timing of AMI technology solution implementation
- Use a staged deployment approach to manage the impact of the new solution
- Use a phased approach to test and operationalize advanced functionality
- Due diligence through requirements design and vendor planning
- Customer engagement and education

Conduct ongoing risk management and mitigation

PPL Electric has created an ongoing risk management process to track and manage the program risks mentioned above and others as they are identified. This process includes identifying of risks and evaluation of the possible impacts, in addition to creating mitigation plans to manage them. Furthermore, the Company is leveraging the extensive experience it gained during the installation of its first AMI solution in 2002, and from successfully operating that system to this day. The lessons learned from the first deployment have been used repeatedly in the strategy for the proposed AMI solution upgrade. These have included insights into scheduling, effective use of pilot programs to trial new functionality, lessons regarding technology obsolescence, and comfort with high read rates from an automated metering infrastructure.

Participate in site visits with vendors and peer utilities

In addition to the lessons learned from its own prior deployment, the Company will continue to engage with vendors of smart meter technology and peer utilities that have used those vendors for their own deployments. This engagement will take the form of attending industry conferences, in-person site visits, and conference calls and other meetings to gain insights and learn best practices for specific solution types.

As PPL Electric is recommending an RF Mesh solution, it will focus on site visits with utilities that have successfully deployed and operated this type of AMI technology. Site visits will allow the Company to learn first-hand the possible issues and risks associated with the solution and will include insights into the challenges of overcoming RF propagation in geographic areas similar to the Company's (urban / suburban / mountains / flat terrain). Additionally, PPL Electric anticipates that it will gain strong insights into the optimization of RF networks and plans to leverage these best practices with its own Network Operating Center and deployment management processes.

Visits with vendors will allow for similar insights from a different lens – providing a view of the details of RF technology and learning first-hand what can be done to ensure successful use of an RF technology for PPL Electric's AMI solution. This will also allow the Company to structure vendor contracts in such a way that vendor performance risk is mitigated.

Engage industry expertise and external program support

Beginning as early as 2009, PPL Electric retained external consultants from Black & Veatch experienced with smart meter deployments to assist in evaluations of the current state AMI solution. The Company continued this practice in 2013-2014 with the engagement of IBM. PPL Electric will continue the practice of soliciting vendors who have high levels of experience with the chosen AMI solution, including technology vendors for solution hardware: meters, head end technology, NOC, and MDM. Vendor contracts will be written considering lessons learned from AMI programs at peer utilities.

Hardware vendors will also be required to submit to industry-approved testing processes, to ensure compliance with nationally-recognized credentials and measures for security, safety, and operation. PPL Electric will also conduct its own vigorous testing in both lab and field environments. Lab and field testing will include detailed end-to-end testing of meters and communications.

Engaging external support will allow the Company to mitigate a variety of risks, including resource availability through the use of external staff augmentation for project staff and potential operation of the legacy AMI system. Contracted services will also be used to mitigate risk during the meter deployment through the use of a Company-chosen meter deployment vendor to conduct physical meter installations at customers' premises. Vendor support may also be leveraged for IT integration efforts.

Deploy a flexible AMI solution

PPL Electric's choice of an RF technology type allows for technical flexibility versus other technology types. RF technology has seen high adoption rates for AMI solutions in recent years. Based on the Company's assessment completed in 2013, an RF solution type also allows for integration with distribution automation and advanced analytics capabilities.

A flexible solution type also mitigates several of the risks mentioned above. New requests from regulatory or legislative bodies will be easier to respond to with a system that is more flexible, and the risk of technology obsolescence is mitigated through the use of a widely-adopted technology type. It is noted that PPL Electric's peers in Pennsylvania have all chosen to deploy RF-based AMI solutions to comply with Act 129 requirements.

Strategic timing of AMI technology solution implementation

As described in the SMP Roadmap contained in Section V. Implementation Plan, PPL Electric plans to complete the required IT and business process review to implement an IT system architecture change and install a new AMI head-end, MDMS, MAM, NOC and customer portal prior to meter deployment in 2017. This is a significant IT and business effort that will require external vendor support. The intent of adopting this aggressive IT build is to minimize potential re-work involved with integrating RF mesh communication systems and meters to the Company's existing AMI systems. This plan improves program efficiency, but makes IT system implementation a critical path item in the schedule requiring adequate support from the PMO and external system integrator.

Use a staged deployment approach to manage the impact of new functionality

As described in Section V. Implementation Plan, deployment will begin in the second half of 2016 with a Solution Validation period. This phase is designed to ensure that the system is functional end-to-end prior to beginning full deployment.

Beginning with full deployment in 2017, smart meter functionality will be staged through 2019 to accommodate IT build timeframes and to allow for proving out of functionality to support Act 129 and Implementation Order requirements.

Use a phased approach to test and operationalize advanced functionality

PPL Electric has been very successful in using pilot programs and proof of concepts to trial new features prior to operationalization and has successfully demonstrated this since 2009 when it began its Smart Meter Plan. The Company will continue this practice during the Smart Meter Program by identifying advanced functionality that could be supported by the upgraded AMI solution, and carefully plan for and stage that functionality.

This approach will be used for new functionality enabled by the AMI solution that is not already operationalized within PPL Electric's business. This will include redesigning business processes to fully utilize meter data, such as voltage, temperature, "last gasp" / power restoration messages, and other message alerts. Additionally, expanded or new functionality such as remote disconnect and HAN devices will be staged throughout the deployment period. Some of the later-stage applications of the new AMI solution, include integration with distribution automation, the use of advanced analytics, and other areas as identified by future business requirements.

Due diligence through requirements design and vendor planning

PPL Electric has already begun the process of developing detailed business requirements for vendor RFPs which will be issued later this year. These requirements will contain business and functional areas required for compliance by vendors involved in the RFP process. PPL Electric will include compliance with the determined requirements as part of the scoring of vendors during the RFP evaluation process and prior to selecting a vendor for the major components of the upgraded AMI solution. Additional detail on the vendor selection process is in Section IV. Vendor Selection for Future Technologies.

Detailed requirements, along with clear roles and responsibilities, establishing service level agreements, and having a disciplined program management approach will help to mitigate risks related to vendor performance and integration.

Customer engagement and education

PPL Electric recognizes that the proposed RF Mesh AMI solution is a new technology both for itself and for its customers. As such, the Company will prepare educational materials to ensure that customers are educated on the benefits and uses of the technology. This education will include details regarding the protection of customer data, and the security measures put in place by the Company to protect both customer and business data in its IT systems and communications networks.

IX. Program Benefits

As an early adopter of AMI technology, PPL Electric has realized significant benefits from installing the current system. The most significant benefit achieved was from the elimination of physical meter reading operations for all of its electric customers as well as associated meter reading support equipment, vehicles, and systems. The Company also realized benefits from improved reliability in customer billing and outage management. Additionally, the Company has been piloting and implementing projects to enhance its PLC metering system and processes as part of its original smart meter implementation plan submitted in August 2009. Some of these pilots, such as remote connect/disconnect, voltage and momentary monitoring, and validating outage durations have been implemented and are delivering benefits by enhancing operations, outage management and customer service, albeit on a limited basis. Other pilots that were implemented, such as developing a supplier portal, providing customers with price and usage information, and implementing a meter data management warehouse and analytics platform have improved the Company's ability to provide information to customers and suppliers. An additional set of pilots such as 15 minute interval data, replacing wired communications with cellular backhaul for meter data, and upgrading meter data collection equipment with new processing boards were implemented to test the PLC system on its ability to deliver Act 129 functionality, lower operating costs, and improve meter reading performance.

Having already realized benefits from its earlier smart meter installation and pilots, PPL Electric will include any additionally realized benefits associated with the proposed smart meter deployment plan in subsequent base rate cases. The proposed Smart Meter Deployment Plan will provide a foundation to realize future customer and operational benefits. Expected benefits include reduced meter services support, decreased call center volumes, improved outage management, improved identification, and cost recovery of unaccounted-for energy.

In the area of meter services, the proposed AMI solution will include remote connect / disconnect switch functionality that will reduce the number of physical visits associated with voluntary and involuntary service reconnections and terminations. The Company will use this functionality in accordance with all applicable rules and regulations. The Company will respond remotely to customer connect and disconnect requests in a timelier manner thereby increasing customer satisfaction in the process. Additionally, the replacement of an aging meter population (characterized by an increasing meter failure rate) with a brand new meter population has the added benefit of reducing the Company need to respond to meter replacements due to failures. As such, any reduction in physical visits will also result in a reduction in labor costs, vehicle and mileage costs, and other support equipment costs such as hand held devices.

Operating benefits may accrue due to a reduction in the number of incoming calls to the customer call center. After an anticipated increase in call volumes during the initial deployment period due to customer questions about the new meters, there is an expected lower net steady state of call volumes. Most of the decrease is expected to be from reduced customer calls inquiring about a timely reconnection of service, after payments they have made related to a non-pay disconnect.

Additional benefits are also expected in the area of power quality, due to further development of the ability to monitor and analyze momentary outage and voltage issues. The ability to get information more frequently and across all smart meters will enhance our ability to analyze and proactively resolve distribution problems prior to customers notifying us about an issue. This will enable PPL Electric to better serve customers and utilize maintenance resources more effectively.

Outage management processes will be improved as PPL Electric introduces "last gasp" and power restoration message capability within the upgraded AMI solution. These capabilities will enable faster detection of outages and will speed power restoration processes. The upgraded AMI solution will also be able to provide near real-time outage status for individual meters. This will more accurately reflect the current state of restoration activity and allow resources to be utilized more effectively such that "OK on Arrival" occurrences (i.e. a power outage is restored on a separate, previous outage ticket) can be identified before a field crew is sent to a premise. As a result, the Company will be able to more effectively deploy and coordinate emergency restoration resources. This has the potential of translating into decreased time spent on storm restoration and reducing overtime and contractor expenditures.

AMI systems coupled with advanced analytic capabilities will allow for improved tracking of unaccounted-for energy, such as theft and tampering, by improving the ability to identify energy usage anomalies and correlating various events. The reduction of energy consumption on inactive accounts will also be realized by having the ability to remotely disconnect these premises, in accordance with applicable regulatory requirements, where otherwise it would have been imprudent to dispatch a crew due to costs and other work priorities. The end result is a customer benefit from a more equitable system where the true responsibility of payment is borne by the parties responsible for the energy usage.

The upgraded AMI solution will support enhanced customer self-service. The direct access capabilities of the new meters will enable In Home Displays through which customers can view and analyze near real time usage information. Additionally, the upgraded customer portal will enhance customers' capabilities to analyze their energy history, review and compare promotions and rate plans, view and pay their bills online, and request start, stop, or transfer of service. Self-service may also improve operating efficiencies by decreasing customer call volume.

Another benefit from AMI systems coupled with advanced analytical capabilities is an improvement to distribution load management and other processes through the application of voltage and load monitoring. This monitoring will provide pertinent information for maintaining electrical system reliability, proactive correction of customer voltage issues, improved distribution load management, and improved accuracy of electrical equipment health monitoring. The aggregated meter data can also provide valuable input to the electric system planning process.

The proposed AMI solution enables several societal benefits such as decreased emissions by facilitating a competitive marketplace. Decreased emissions of CO_2 can result from lower energy consumption and less mileage due to fewer premise visits. The AMI system can facilitate a competitive marketplace by enabling in home customer displays, thereby influencing peak purchases and as a result applying downward pressure on energy prices in spot markets.

The benefits of implementing the SMP are difficult to quantify. For example, when implementing the remote connect/disconnect functionality, the Company anticipates reduced service visits to customers' premises. However, the Company may not necessarily reduce its staff to account for this functionality but may use its resources to perform other activities. The Company may also experience lower call volume, but it is not possible to predict with any accuracy a precise amount that this would reduce the Company's operating expense. In addition, many of the benefits will not be fully realized until the SMP is implemented.

Due to the uncertainty and difficulty in quantifying operational savings associated with implementing the SMP, the Company proposes to reflect any savings associated with the SMP in future base rate cases as these savings are reflected in the Company's operations.

X. Financial Overview

A. Costs

In response to Act 129 and the Commission's subsequent Implementation Order, PPL Electric initiated an assessment and planning effort in preparation for the implementation of smart meters and AMI technologies. A key input supporting planning was the creation of a cost model ("Financial Analysis") to estimate and analyze the future operating costs and capital expenditures associated with the deployment. The analysis covered the period beginning in 2014 and through the end of the stabilization period, i.e. 2021.

The data underlying the financial analysis were gathered through an assessment process involving RFIs from vendors, industry experience, subject matter experts from PPL, and consulting support from IBM. The data were reviewed and updated in an iterative process throughout 2013 and 2014. Activities performed in the development of the Financial Analysis included:

- Defining the scope and components of the smart meter program
- Gathering relevant operational data and smart meter project projections
- Evaluating and validating data
- Identifying key smart meter project financial analysis modeling variables and assumptions
- Developing the analytical modeling structure
- Constructing a detailed view of the smart meter project financial analysis
- Reviewing the Business Case results with PPL Electric stakeholders and management

The financial analysis included in this chapter is based on the 3-year recommended deployment schedule. This schedule anticipates all smart meter infrastructure will be built and all smart meters installed by the end of the year 2021. Based on this analysis, the total estimated cost of implementing this plan (2014-2021) is $449.3 million, $407.9 million for capital expenditures and $41.4 million for Operations and Maintenance (O&M).

Table 2 shows a summary of the Company's costs by major cost category, and Figure 15 - 8-Year Cost Schedule shows an 8-year cost schedule from 2014 – 2021.

Table 2 - Cost Summary ($ Millions, Nominal 8 years)

Category	Capital	O&M	Total
Meter	$284.9	$0.0	$284.9
Network & Network Management	$31.4	$7.9	$39.3
Information Technology	$53.0	$24.7	$77.7
Systems Integration	$8.8	$0.0	$8.8
Program Management	$23.2	$5.4	$28.6
Communications/Change Management	$6.6	$3.4	$10.0
Totals	$407.9	$41.4	$449.3

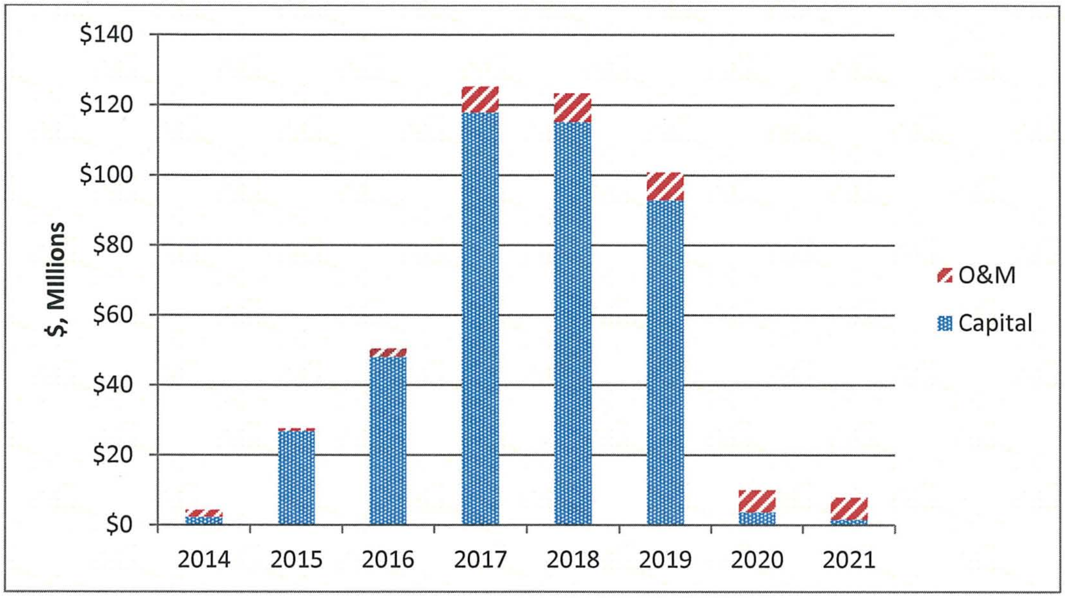


Figure 15 - 8-Year Cost Schedule

PPL Electric's projection of costs for the various components of the SMP are high level estimates based on data provided by potential vendors in response to the Company's RFIs and further based on the Company's business experience. These high level estimates are subject to change for a variety of reasons, including but not limited to, increases in vendor prices, changes in project scope, changes in the implementation timeline, unforeseen complications or changes in regulatory requirements. The cost estimates are not precise and will be revised over the life of the project. PPL Electric intends to recover its actual smart meter costs through the SMR whether they are more or less than the Company's initial estimates.

B. Scope & Assumptions

The financial analysis assumes an 8-year timeframe, starting with the beginning of the Post-Grace Period on July 1, 2014 and continuing through the end of the stabilization period in 2021. The Business Case assumes a 3-year deployment schedule that will commence in 2017. Additional Assumptions include:

- Annual work hours per Full Time Equivalent (FTE): 2080 hours (52 forty-hour weeks)
- Communications infrastructure will be deployed prior to meter deployment in each specific geographic area
- Costs for the following were based on RFI responses:
  - Meters
  - Network communications
  - Head end
  - MDM
  - Portal
- Costs for the following were based on PPL Electric and industry experience:
  - Program management
  - Change management and communications
  - IT support

  - System integration
- The decision to purchase in home customer devices such as displays, smart thermostats, etc. will be left to the customer, as such no costs associated with these devices have been included
- The analysis assumes 100% deployment; customers will not have an option to opt out
- A deployment vendor will be used for deploying meters in the field
- Prior to deployment, meter base related repairs are assumed to be needed on 3% of the meter population. The cost to repair each issue is estimated to be $1500

C. Overall Program Costs

The costs incurred to implement this plan have been grouped into the following cost categories: (i) Meter; (ii) Network & Network Management; (iii) Information Technology; (iv) Systems Integration; (v) Program Management; (vi) Communications/Change Management. Within each of these categories, the costs were further broken down as either capital or O&M within the years over which these costs would be incurred. The costs have been presented on a nominal basis over an 8 year analysis period. A graphical representation of these costs is shown in Figures 17 and 18.

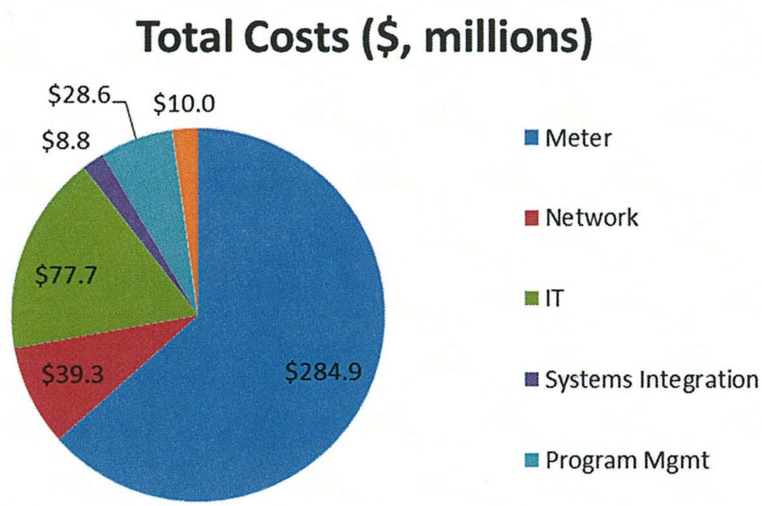


Figure 16 - Total Cost Breakdown

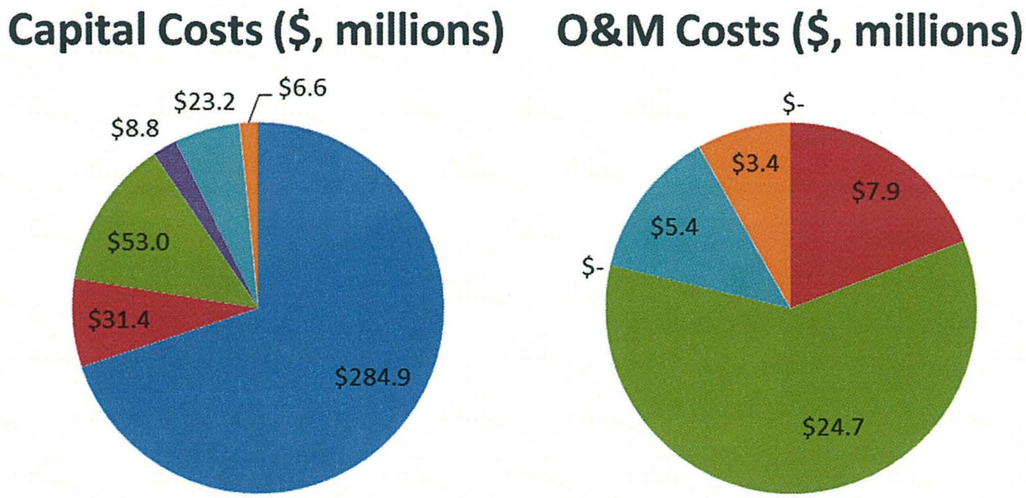


Figure 17 - Capital and O&M Cost Breakdowns

The capital costs constitute approximately 91% of the total costs and the O&M costs constitute the remainder of the total costs. A breakdown of costs in capital and O&M categories is shown in Figure 17. The cost estimates are based on program components described below:

D. Costs by Program Component

1. Meter

Total estimated cost: $284.9 million

Capital: $284.9 million

O&M: $0.0 million

The most significant component of the meter cost is the $193.8 million equipment cost for the approximately 1.4 million meters. A deployment vendor would be used to deploy meters at an average installation cost of $12.50 per meter and will total $20.0 million. Another component of the meter cost is related to repair of customer meter bases prior to full deployment totaling $67.2 million. Other items that are included in the total meter cost are associated with meter testing, meter failures, and customer growth.

2. Network & Network Management

Total estimated cost: $39.3 million

Capital: $31.4 million

O&M: $7.9 million

The network equipment costs which include repeater and collector costs will be $9.9 million. The model assumes approximately 2,900 repeaters and 600 collectors will be needed. The total costs to deploy and install the network communications system will be $3.9 million and will include $2.6 million for project management, network planning and engineering, training, and testing and $1.3 million for equipment installation in the field.

In addition to the costs associated with the installation of a network communications system, there will be additional costs to monitor and run a smart meter NOC totaling $6.7 million. Other components of the network and network management costs include backhaul, annual component failures, and annual maintenance.

3. Information Technology

Total estimated cost: $77.7 million

Capital: $53.0 million

O&M: $24.7 million

Costs associated with software, hardware, vendor support and internal IT resources are all part of the Information Technology costs. The software costs of Head-End, MDM, Portal and Meter Asset Management System total $33.0 million while the associated hardware costs are $7.2 million. Resource costs including incremental internal PPL IT resources and external vendor support are $37.4 million.

4. System Integration

Total estimated cost: $8.8 million

Capital: $8.8 million

O&M: $0.0 million

The system integration category captures the costs associated with coordinating and managing the implementation of the different IT packages in an optimal manner. Associated tasks include providing overall architectural guidance and design, supporting security requirements, facilitating integration across the disparate systems and comprehensive test plan development and execution.

5. Program Management

Total estimated cost: $28.6 million

Capital: $23.2 million

O&M: $5.4 million

The program management category captures the costs associated with overseeing the entire program through the end of 2021. The responsibilities associated with this category include program leadership, project management, requirements gathering, deployment planning, vendor management and business process development and redesign. The PMO costs associated with external consultant support is also incorporated into this category.

6. Communications/Change Management

Total estimate cost: $10.0 million

Capital: $6.6 million

O&M: $3.4 million

The estimated communications and change management costs cover two categories – training costs totaling $1.4 million and stakeholder communications costs totaling $8.6 million. Training costs include costs associated with both the development of training guides and modules as well as the delivery of training. The costs associated with communications incorporate costs for the development of smart meter plan related materials for all stakeholders as well as costs to deliver relevant education and messages through the appropriate channels in accordance with the timeframes outlined in the Communications Strategy.

XI. Communications Strategy

A critical component of the Smart Meter Plan will be a series of communications activities related to the deployment project, education of customers for smart meter technology, and other communications with various communities and regulatory agencies.

PPL Electric's communications related to the Smart Meter Plan will ensure that customers are informed about AMI benefits and the installation experience, including when they can expect new meters. The Company also intends to provide sources of information about AMI, and contact information for scheduling installation appointments. These activities will also include addressing any concerns (security, privacy, health effects, etc.) about the program.

In addition to customer-facing communications, PPL Electric will educate and inform employees, stakeholders, members of the media, public officials, and other audiences about why PPL Electric is upgrading to advanced meters.

The smart meter team has identified a series of key messages which will be part of the Company's communication strategy. These messages will be tailored to specific audiences and timeframes as part of a comprehensive communications plan. The Company plans to develop this comprehensive plan following approval of this SMP filing and prior to beginning deployment. The comprehensive plan will also leverage information provided by selected vendors for the AMI solution. PPL Electric will communicate the comprehensive plan with the Commission upon completion.

A. Key Messages

- PPL Electric Utilities proposes to upgrade its existing advanced meters to provide additional capabilities, improving service to customers and complying fully with Act 129.
- The new system will:
  - Comply with Act 129 and Implementation order requirements, including enabling customers to receive real-time pricing information.
  - Support home area networks, providing additional real-time information to customers regarding energy usage and cost.
  - Support operational improvements, including remote connect / disconnect and outage detection and restoration.
- After thorough study, we have determined that we will propose an RF solution, as opposed to our current Power Line Carrier system.
- Based on current analysis, we expect the project cost will range between $425 and $450 million.
- We expect to deploy the meters between 2017 and 2019.

B. Key Audiences

- PPL Electric customers
- Smart Meter Stakeholder Group
- Elected officials
- Other PPL Electric employees in Pennsylvania
- Media

- Public or community groups, such as chambers of commerce, consumer organizations, low income advocacy groups, etc.
- Financial/investment community
- IBEW 1600 leaders/contractors
- PPL Electric Retirees
- EGSs

C. Key Channels

- Dedicated internet website which will contain program information, Frequently Asked Questions (FAQs), and contact information
- Education for call center representatives
- Meetings with communities and public leaders
- Direct mail and E-Mail messaging
- Customer bill inserts
- On-premise notifications (during deployment)

A successful communications plan will rely on several key strategies. PPL Electric will leverage proven communications strategies used during its initial deployment of smart meters and will ensure employees have the information they need to understand the reason for new advanced meters and to communicate with family, friends and neighbors. Additionally, PPL Electric will conduct necessary consumer research to understand/refine messages and to ensure messages and supporting information are appropriately targeted

As part of its communications strategy, PPL Electric will create a detailed communications plan for deployment communications.

D. Deployment Communications

PPL Electric will also create communications materials related to the deployment of upgraded smart meters from 2017 – 2019. These communications will focus on notifications to customers of the deployment schedule, including proactive notifications prior to premise visits to install the upgraded meters. PPL Electric will follow a staged process to communicate deployment activities to customers:

1. 90 days prior to installation

During this phase, PPL will notify customers that deployment is being planned in their region or geographic area. This communication will include education about the upgraded smart metering system and website information to access additional detail via the dedicated microsite. Also during this phase, PPL Electric will, as appropriate, hold meetings with public leaders, and conduct other outreach sessions to proactively educate customers prior to installation.

2. 60 days prior to installation

PPL Electric will continue customer education and outreach efforts during this phase. These efforts will also include additional FAQs developed in tandem with the deployment vendor to address any customer concerns.

3. 30 days prior to installation

During this phase PPL Electric will send direct mail and E-mail notifications to customers reminding them of the upcoming premise visit to install an upgraded smart meter. The Company will provide an estimated timeframe for the day(s) during which the installation will take place.

4. Post-installation

PPL Electric will use contracted deployment vendors for the installation, which will take place according to a standardized process. Following the installation of an upgraded smart meter, PPL Electric will notify customers of the premise visit via a door hanger or other similar mechanism.

One week after the installation, PPL Electric will provide a survey to customers requesting feedback regarding the installation experience and the value of any provided communications materials. Customers will also be able to provide this feedback via the microsite.

XII. Cost Recovery

PPL Electric proposes to recover smart meter technology costs through its Smart Meter Rider consistent with the provisions of Act 129.

A. Current Smart Meter Plan Cost Recovery

In its 2009 Smart Meter Plan filing, PPL Electric proposed recovery of Smart Meter technology costs through a rider. In accordance with the Commission's Order at Docket No. M-2009-2123945, the Company implemented a separate mechanism, the Smart Meter Rider ("SMR"), on January 1, 2011 and, since that time, has filed quarterly informational reconciliations and annual 1307(e) reconciliations. PPL Electric includes a financial update and rate filing in its annual Smart Meter Plan filings in August of each year and has submitted proposed SMR changes to take effect in the following calendar year in addition to reconciliation of the Company's SMR charges from the previous year.

Currently, PPL Electric recovers the annual budgeted amount of all costs required for the Company to implement its approved Smart Meter Plan during a compliance year. The SMR is applied on a non-bypassable basis to charges for electricity supplied to customers who receive distribution service from the Company. It is applied to Residential and Small Commercial and Industrial (C&I) customers on a $/kWh basis and to Large C&I customers on a $/bill basis. The annual budgeted amount is the sum of all direct and indirect capital (e.g., return of and return on applicable smart meter-related investment) and operating costs (e.g., applicable O&M and taxes), including all deferred design and development costs and general administrative costs required to implement the Company's SMP in the compliance period.

PPL Electric proposes to continue recovering through the SMR the cost of the pilot programs and any associated over or under recovery.

In the 2013 filing, PPL Electric stated that the Final Plan will propose recovery of any additional AMI costs, subject to Commission approval as an adjustment to the SMR.

B. Proposed Smart Meter Plan Cost Recovery

PPL Electric is proposing modifications to its Smart Meter cost recovery mechanism.

The Company is proposing that the SMR be stated as a per-customer charge for all Residential, Small C&I and Large C&I customers. This price will be updated quarterly and will be based on historical, actual data for the prior three-month period with a one-month lag. PPL Electric will continue to file quarterly informational reconciliations and annual 1307(e) reconciliations.

PPL Electric proposes to continue recovery of annual costs required for the Company to implement its approved Smart Meter Plan during a compliance year. Qualifying plan development and implementation expenses incurred during 2014 will be deferred and recovered over three application years. The SMR will be applied on a non-bypassable basis to charges for electricity supplied to customers who receive distribution service from the Company. The amount eligible for recovery is the sum of all direct and indirect capital (e.g., return of and return on applicable smart meter-related investment) and operating (e.g., applicable O&M) costs, including all deferred design and development costs and general administrative costs required to implement the Company's SMP in the compliance period.

The Company will include in its calculation the costs of eligible plant additions and operating costs that have not previously been reflected in PPL Electric's rates or rate base. Thereafter, the SMR will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month period ending one month prior to the effective date of each SMR update. PPL Electric will also include in its calculation operating costs for the three-month periods ending one month prior to the effective date of each SMR update.

The SMR will be subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year. The revenue received under the SMR for the reconciliation period will be compared to PPL Electric's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year. If SMR revenues exceed SMR-eligible costs, such overcollections will be refunded with interest. If SMR-eligible costs exceed revenues, such undercollections will be collected with interest. Interest on over/under-collections will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.).

The Company's return shall be calculated using PPL Electric's actual capital structure and actual cost rate for long-term debt as of the last day for the three-month period ending one month prior to the effective date of the SMR and subsequent updates. The cost of equity will be the equity return rate approved in PPL Electric's last base rate proceeding that is less than three years old. If, however, the last base rate case is more than three years old, the quarterly return on equity calculated and recommended by the Bureau of Technical Services for the Distribution System Improvement Charge in the then most recent Quarterly Earnings Report will be utilized until a return on equity is determined in a subsequent base rate case. Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

C. Unrecovered Costs of Assets to be Replaced

PPL Electric's proposed SMR does not include an adjustment for recovery of the costs of its existing meters. The Company proposes to continue depreciating its existing meters using their current depreciation schedule and to continue to recover depreciation on existing meters through its distribution base rates until the next distribution rate case. In its next base rate case, PPL Electric will propose to accelerate the period over which it will recover the remaining unrecovered investment in AMR. PPL Electric will propose a recovery period that coincides with the completion of the new meter deployment period throughout its territory to recover its AMR investment that remains unrecovered as of December 31 of the fully projected future test year included in that rate case.

Appendix A

Appendix A: Glossary of Terms

ADIT - Accumulated Deferred Income Taxes

AMI - Automated Metering Infrastructure: technology that, among other capabilities, eliminates the need for manual meter reading by incorporating advanced communications systems into grid components

ANSI - American National Standards Institute

ANSI C12.19 - American National Standard for Utility Industry End Device Data Tables

ANSI C12.22 - American National Standard for Interoperability among Smart Meters and Communication Devices

BC - Business Continuity: Part of PPL's operational readiness testing

BIT - Business Integration and Testing: Workstream for managing all lab and field testing related to the smart meter program

C&I - Commercial and Industrial: Large customers

CIA - Confidentiality, Integrity and Availability

CIS - Customer Information System: Back end system

CISSP - Certified Information Systems Security Professional

CISM - Certified Information Security Manager

CSIRT - Computer Security Incident Response Team

CSP - Customer Service Provider

Customer Portal - System which presents energy usage information to customers via a web interface. Portal was first deployed to PPL customers in June of 2007

DDoS - Distributed Denial of Service: Cyber-attack where one system is compromised by concentrated signals from multiple systems

DR - Disaster Recovery: Part of PPL's operational readiness testing

DHS - Department of Homeland Security

DoE - Department of Energy

DSIC - Distribution System Improvement Charge: A PUC-allowed surcharge on utility billing to fund the replacement of crucial aging infrastructure

EDC - Electric Distribution Company

EDI - Electronic Data Exchange

EDEWG - Electronic Data Exchange Working Group

EEI - Edison Electric Institute: Association of all shareholder-owned electric companies in the U.S.

EGS - Electric Generation Supplier

Electro-Mechanical Meters - Traditional rotating-disk electrical meter

ES-C2M2 - Electricity Subsector Cybersecurity Capability Maturity Model

ES-ISAC - Electricity Sector Information Sharing and Analysis Center

FBI - Federal Bureau of Investigation

FERC - Federal Energy Regulatory Commission

FERC OEIS - Office of Energy Infrastructure Security

FTE - Full Time Equivalent

HAN - Home Area Network

IAG - Information Assurance Group

IBEW - International Brotherhood of Electrical Workers

IEEE - Institute of Electrical and Electronics Engineers

IEEE 802.15.4 - Standard for low-power wireless networks (e.g., Zigbee)

IHD - In Home Displays

ISO - Independent System Operator

IT - Information Technology

KWh - kilowatt hour, the standard energy consumption unit for electricity meters

<u>MAM</u> - Meter Asset Management

<u>MDM</u> - Meter Data Management system: System that supports processing of meter data collected from the AMI system and interfaces directly with a customer portal

<u>NERC</u> - North American Electric Reliability Corporation

<u>NERC CIP</u> - Critical Infrastructure Protection

<u>NIST</u> - National Institute of Standards and Technology

<u>NOC</u> - Network Operating Center

<u>O&M</u> - Operation and Maintenance

<u>OCA</u> - Office of Consumer Advocate

<u>P2P</u> – Point-to-Point

<u>PA PUC</u> - Pennsylvania Public Utility Commission

<u>PCADV</u> - PA Coalition Against Domestic Violence

<u>PECO</u> - Energy Company in Philadelphia, subsidiary of Exelon.

<u>PIA</u> - Privacy Impact Assessment

<u>PLC</u> - Power Line Carrier: technology wherein data from meters is transmitted via existing power line infrastructure

<u>PMO</u> - Project Management Office

<u>Post Grace Period</u> – Denotes the time period following the end of the Grace Period for smart meter deployments as defined by the Commission. For PPL Electric, the Post Grace Period begins following the submittal of its final SMP

<u>PPLICA</u> - PP&L Industrial Customer Alliance

<u>PUC</u> - Public Utility Commission

<u>PULP</u> - Pennsylvania Utility Law Project

<u>Reliant Energy</u> - Power Utility located in Texas, a subsidiary of NRG Energy

<u>RFI</u> - Request for Information

<u>RF Mesh</u> - Radio Frequency Mesh

<u>RFP</u> - Request for Proposal

<u>RTO</u> - Regional Transmission Organization

<u>RTP</u> - Real-Time-Price

<u>Smart Meter Technology</u> – As defined in Act 129, metering technology and network communications technology with the fundamental capabilities of bidirectional communication, recording electricity usage on at least an hourly basis, and providing customers with direct access to and use of price and consumption information.

<u>SMP</u> - Smart Meter Plan

<u>SMR</u> - Smart Meter Rider

<u>SRA</u> - Security Risk Assessment

<u>SI</u> - System Integrator

<u>TOU</u> - Time-of-Use

<u>TWACS</u> - Two-Way Automatic Communications System: PLC AMI solution from Aclara, utilized in PPL's initial AMI deployment and in PPL Electric's current solution.

<u>VEE</u> - Validation, Estimation, and Editing

<u>Zigbee</u> - Low-power wireless technology based on the IEEE 802.15 standard

Appendix B

APPENDIX B

PPL Electric Utilities Smart Meter Program Budget	2010	2011	2012	2013	2014	Total
6 B(1): Bidirectional data communications capability						
Note: Demonstration of this functionality will be provided in conjunction with home area network pilot to be completed in Section 6 C(4).						
6 B(2): Recording usage data on an hourly basis at least once per day						
Note: PPL Electric does not anticipate any incremental costs to be expended except for meter replacement under normal conditions such as damage to the meter, defective meters and customer requests.						
6 B(3): Provide customers with direct access to price and consumption information						
1. Messaging - Price and usage information						
- Evaluate various channels of customer communications	$18,729					**$18,729**
- Pilot		$175,299	$9,743			**$185,042**
2. Faster Data Presentment to Customers and Suppliers			$6,235	$92,494		**$98,729**
Note: Demonstration of this functionality will be provided in conjunction with home area network pilot to be completed in Section 6 C(4).						
6 B(4): Provide customers with information on their hourly consumption						
1. Improved VEE process to incorporate outage data			$11,733	$123,446	$3,051	**$138,230**
Note: Work with customers, EGSs and 3rd parties to provide hourly consumption that is in clear and understandable formats.						
6 B(6):Supporting automatic control if the customer's electric consumption						
1. Load Control Evaluation						
- Conduct pilot of 500 Customer installations	$36,851	$421,795	$9,089			**$467,735**
6 C(1): Remote disconnection and reconnection						
1. Remote Disconnect / Reconnect						
- Conduct pilot		$50,075	$706,909	$166,728	$33,454	**$957,166**
6 C(2): Ability to provide 15 minute or shorter interval data						
1. Performance evaluation of Focus UMT-r meters						
- Conduct pilot with 500 meters	$10,507	$34,086				**$44,593**
6 C(3): On-board meter storage of meter data						
1. Ability to read historical data/process IT						
- Design/development & pilot with Aclara		$13,824	$62,717			**$76,541**
- MDM capability to upload and re-VEE data				$22,682		**$22,682**
6 C(4): Open standards and protocols						
1. In-Home Display/Home Area Network						
- Evaluate available technologies and requirements	$16,761					**$16,761**
- Conduct Pilot with 500 customers		$412,630	$41,748	$76,225	$300	**$530,903**
2. AMI System Security Assessment						
- Assess the current AMI system for security effectiveness				$178,335		**$178,335**
6 C(5): Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible						
1. General Obsolescence and Upgrade Issues						
- Next generation PLC based system evaluation		$241,628				**$241,628**
- Potential next generation PLC based system implementation (TWACS 20 Pilot) [2]			$1,693,734	$69,716	$104,809	**$1,868,259**
- Evaluation next generation AMI technologies			$3,525	$982,345	$16,751	**$1,002,621**
- Assessment of existing PLC based functionality	$12,982					**$12,982**
- Telecommunications Substation Modem evaluation and replacement	$333,962	$180,531	$6,137			**$520,630**

APPENDIX B

PPL Electric Utilities Smart Meter Program Budget	2010	2011	2012	2013	2014	Total
- Real Time Path mapping in PLC based system						
» Evaluate feasibility and potential design			$17,196			**$17,196**
» Implement/evaluate results of proof of concept design						
» Implement full scale			$12,717	$45,210		**$57,927**
- PLC Based System Enhancements						
a. Consider addition of Modulation Transformer Units(MTU)						
» Evaluate the benefits for additional MTUs		$11,332				**$11,332**
» Implement additional TWACS Trailers			$280,481	$4,819		**$285,300**
b. Consider deployment of SCPA G2 Boards						
» Evaluate the benefits for new SCPA G2 boards		$11,332				**$11,332**
» Install SCPA G2 boards			$261,753	$803,842	($5,035)	**$1,060,560**
2. Service Extending						
- Conduct pilot - 500 customers			$7,682			**$7,682**
3. Prepay Metering						
- Conduct pilot - 500 customers			$87,716	$10,057		**$97,773**
4. Momentary Outage Monitoring						
- Conduct pilot		$15,725	$56,049			**$71,774**
- Implement recommendations				$53,839		**$53,839**
5. Accelerated Supplier Switching Project (Off-Cycle)			$18,691	$1,409		**$20,100**
6. MDM Data Warehouse and Analytics			$1,187,475	$801,833	$13,739	**$2,003,047**
7. Supplier Portal Pilot [2]			$17,123	$321,498	$241,192	**$579,813**
8. Power Monitoring for Large Power Meters				$15,804	$42,867	**$58,671**
9. Smart Meter Data Exchange [1]						**$0**
6 C(6): Ability to monitor voltage at each meter						
1. Wireless-based system enhancement	$71,027	$71,645				**$142,672**
2. Voltage measurement/collection/ reporting in PLC-based system						
- Pilot	$4,329	$123,394				**$127,723**
- Full scale implementation and evaluation			$101,247	$30,501		**$131,748**
6 C(7): Remote programming capability						
Note: To be demonstrated in conjunction with work to be completed in Section 6 C(5).						
6 C(8): Communicate outages and restorations						
1. Proactive Outage Detection						
- Assess options to determine how to become more proactive with outage detection	$2,630					**$2,630**
- Implement pilot		$127,985				**$127,985**
- Implement plan			$32,617	$3,036		**$35,653**
2. Outage Duration Pilot and Implementation			$10,733	$95,714	$6,452	**$112,899**
6 C(9): Ability to support net metering of customer generators						
1. Evaluate feasibility customer owned generation with TNS						
- Conduct pilot with Focus UMT-r meters - 100 meters	$77,666					**$77,666**
- Implementation		$99,541	$85,088			**$184,629**
Program Management [2]	$395,846	$306,810	$456,444	$477,864	$1,389,541	**$3,026,505**
Total	**$981,290**	**$2,297,632**	**$5,184,582**	**$4,377,397**	**$1,847,121**	**$14,688,022**

Footnotes

[1] There are no costs associated with the Smart Meter Data Exchange

[2] 2014 data are actual numbers incurred through May 2014 for all pilots/programs except TWACS 20 pilot, Supplier Portal pilot, and Program Management, which has June 2014 estimates included.

Appendix C

APPENDIX C

PPL Electric Utilities Corporation Smart Meter Plan Pilot/Evaluation

6 B(1)
Bidirectional Data Communications

Pilot/Evaluation	• Perform evaluations using in-home displays with home area networks in coordination with the pilot referenced in section 6C(4)
Estimated Cost of Pilot/Evaluation	• Estimated cost of this pilot is outlined in Section 6C(4)
Pilot/Evaluation Plan	• Pilot description is outlined in Section 6C(4)
High Level Benefits	• Benefits are described in Section 6C(4)

6 B(2)
Recording hourly usage data on at least an hourly basis

Pilot/Evaluation	• None was performed, because the Company's current PLC and large-power smart meter systems already meet this requirement.
Estimated Cost of Pilot/Evaluation	• Not applicable.
Pilot/Evaluation Plan	• Continue to deploy meters for new construction, upon customer request, and to replace damaged and defective meters.
High Level Benefits	• The Company's customers already receive the benefits of hourly meter reads such as billing accuracy and increased awareness.

6 B(3)
Provide customers with direct access to and use of price and consumption information

Pilot/Evaluation	**Price and Usage Information** • PPL Electric currently provides electronic access to price and consumption information through their website and through EDI transactions. An initiative was undertaken to evaluate and pilot various alternative communication mediums for providing this information. In addition, the Company developed and implemented messaging enhancements that include alerts on price changes, breaches to user-defined consumption thresholds, and abnormal usage. The evaluation included tests of communication channels such as near real-time email, phone messages, and text messages (SMS) to customers.
Estimated Cost of Pilot/Evaluation	• The project cost was $203,771.

Pilot/Evaluation Plan	• Evaluation of available technologies in 2010
	• Implement in 2011 and 2012 the following:
	    o Messaging alerts to multiple communication channels
	    o Deployment of software and required licensing

High Level Benefits	• Customers will derive increased understanding and awareness of energy usage, which lead to better energy management.
Potential Implementation	• The pilot was a successful demonstration of the capability of PPL Electric's AMI systems to provide timely feedback to customers regarding their electric usage. Eligible customers are currently able to enroll in any of the messages.

6 B(3)
Provide customers with direct access to and use of price and consumption information

Pilot/Evaluation	**Faster Data Presentment to Customers and Suppliers** • The objective of this pilot was to evaluate the changes needed to PPL Electric's AMI infrastructure and back office systems to present validated customer data to customers and their authorized representatives on the Company's website sooner than 48 hours after it was used. The evaluation examined how changes to the validation processes would impact business lines, customers, third parties, EDCs and in the settlement process. • It was decided that the increased costs to present data faster was not cost effective based on the low number of customers who look at their daily read and interval usage data on the web portal.
Estimated Cost of Pilot/Evaluation	• The project cost was $98,729.
Pilot/Evaluation Plan	• Develop scope, cost and detailed schedule • Evaluate all AMI and back office systems that would require changes • Determine net reduction in time to present data • Develop new processes and procedures • Implement changes
High Level Benefits	• Energy usage information available to customers would be more current than that which presently is available, allowing customers to make decisions regarding their electricity use and consumption based on more current information. • Suppliers may be able to offer new products and billing options to customers.
Potential Implementation	• Substantial system upgrade costs are needed to increase the presentation of data within the existing systems. This evaluation will help support faster data presentment in new AMI systems.

6 B(4)
Provide customers with information on their hourly consumption

Pilot/Evaluation	• PPL Electric provides its customers with information on hourly consumption from its AMI. This data is provided on a daily basis to the PPL Electric Meter Data Management System (MDMS), which enables customers to access their individual information on the web portal. • The Company also provides hourly consumption through EDI transactions and on the supplier portal for EGS's and third party use.
Estimated Cost of Pilot/Evaluation	• N/A
Pilot/Evaluation Plan	• N/A
High Level Benefits	• N/A

6 B(4)
Provide customers with information on their hourly consumption

Pilot/Evaluation	**Improved Validation/Editing/Estimation ("VEE") Process to Incorporate Outage Data** • This project's objective was to leverage outage management data to improve the VEE process. • The pilot evaluated the integration of outage data from OMS into the MDM system in order for the VEE process to more accurately estimate missing hourly data without populating data into hours of known outages.
Estimated Cost of Pilot/Evaluation	• The project cost was \$138,230.
Pilot/Evaluation Plan	• Develop a scope, cost and detailed schedule • Analyze missing intervals and compare to the current VEE process • Evaluate the most cost-effective way to integrate outage data into the meter data validation process • Implement changes into the VEE process, if they are proven to be beneficial
High Level Benefits	• Customers would no longer see data appear on PPL Electric's online Energy Analyzer website during the hours they are without service. • PPL Electric's internal algorithms will more accurately profile interval data by avoiding intervals that occurred during a known outage. • Customers will see more accurate data within PPL Electric's online Energy Analyzer website. • Billing that relies on hourly usage will be more accurate. • Better overall data for MDM downstream processes (i.e. settlement, profiles, complex billing, real time pricing, web presentment, etc.).
Potential Implementation	• The pilot is completed. • Changes to the VEE process were moved to production in early 2014, and the improved VEE process now incorporates outage information from PPL Electric's OMS system into the VEE process.

6 B(5)
Enabling TOU and RTP Programs

Pilot/Evaluation	• The objective of this pilot was to conduct a performance evaluation of the Company's ability to collect and deliver 15-minute data at a high success rate for RTP billing, specifically for large power customers with demand greater than 500 kW. This evaluation was part of the 15 minute study discussed in Section 6C (2). • Due to PLC system limitations for real-time pricing, PPL Electric determined that it was more cost effective to read the accounts with greater than 500 kW demand with the large power meter wireless system. This amounted to changing 320 accounts from the PLC system to the MV90 system. • The meter change over to MV90 was completed in 2010 outside of the Smart Meter Plan.
Estimated Cost of Pilot/Evaluation	• N/A
Pilot/Evaluation Plan	• N/A
High Level Benefits	• Enables RTP for Large C&I Customers.

6 B(6)
Supporting the automatic control of the customer's electric consumption

Pilot/Evaluation	**Load Control** • The objective of this pilot was to further extend the benefits of the currently deployed AMI system to demonstrate how it meets this minimum requirement of load control. This was accomplished by installing load control devices on air conditioning systems and water heaters. In addition, PPL Electric required that participating customers have the ability to opt-out of any specific load control event. Pilot planning began in 2010 and the pilot was completed in 2011.
Estimated Cost of Pilot/Evaluation	• The project cost was $467,735.
Pilot/Evaluation Plan	• Establish pilot objectives • Invite customers to participant in pilot (177 customers participated) • Purchase and install load control devices • Develop/implement required software and IT programming changes and licensing • Evaluate pilot results • Results and proposed implementation plan presented to the Commission in this filing
High Level Benefits	• Allows customer to take advantage of TOU rate options • Enables customers to shed load during periods of peak pricing • Provides capability for PPL Electric to shed load during emergency load reduction events called by PJM to maintain system reliability
Potential Implementation	• The future costs have been reduced by $8.2 M from 2013 to 2015 because the Company is not proposing to implement this pilot.

6 C(1)
Ability to remotely disconnect and reconnect

Pilot/Evaluation	**Remote Disconnect/Reconnect** • The objective of the remote connect/disconnect pilot was to (1) test the performance of the remote switch capability, (2) determine the costs associated with automating the use of a remote disconnect/reconnect device, and (3) track benefits through the collection of data during the pilot. • Potentially there are also qualitative benefits in the form of customer satisfaction by expediting service connections, as well as safety benefits by removing field representatives from potential hazardous conditions. • The 500 meter pilot found the meter and integration functionality was successful and the pilot was implemented system wide in the first quarter of 2014.
Estimated Cost of Pilot/Evaluation	• The project cost was $957,166.
Pilot/Evaluation Plan	• Establish pilot objectives • Identify locations for pilot meter installs • Purchase of meter hardware and installation • Develop/implement required software and IT programming changes and licensing • Evaluate pilot results • Establish potential implementation plan • Report results and proposed implementation plan to the Commission
High Level Benefits	• Contributes to the reduction in consumption on inactive meters • Eliminates need to dispatch personnel to disconnect and reconnect • Provides ability to comply with Commission regulations in normal connect/disconnect situations • Automates the process for completing connects and disconnects
Potential Implementation	• Evaluation for extended use of the remote functionality will be explored at a later date.

6 C(2)
Ability to provide 15-minute or shorter interval data

Pilot/Evaluation	**15 Minute Interval Data** • The objective of the 15-minute interval data pilot was to gather information on PPL EU's ability to scale the PLC meter reading system to collect 15 minute interval data from all small C&I customers. In addition PPL EU was asked to investigate and answer eight questions regarding the impact of 15 minute intervals on customer's accessibility to ancillary programs. • A pilot was conducted in 2010 and 2011 to determine the feasibility of providing 15-minute interval data in the PLC system using installed meters that have the capability to be configured for 15-minute data collection at the small commercial customer level. In addition, a scalability test was completed to determine if PPL Electric's power line system can handle reading 15-minute data from all small commercial accounts without significant investment into the power line system. • Based on the pilot, a cost benefit analysis determined the economic value of implementing 15-minute interval data reads to all small commercial customers through the Company's power line carrier system was not a cost effective option. • The Company proposed to maintain its current process of providing customers with 15-minute interval data upon request through KYZ pulses.
Estimated Cost of Pilot/Evaluation	• The project cost was $44,593.
Pilot/Evaluation Plan	• Remote reconfiguration of installed smart meters from 60 minute interval data to 15-minute interval data collection • Scalability test • Evaluate pilot results • Cost Benefit Analysis • Development of recommendations • Report results and an implementation plan to the Commission.
High Level Benefits	• Determine the most cost-effective method for providing customers with interval data to meet the needs of customers, third-party aggregators and EGS's.
Potential Implementation	• Based on the pilot results no implementation of 15 minutes will be executed in the PLC system.

6 C(3)
On board meter storage of meter data

Pilot/Evaluation	**On-board meter storage** • The objective of this pilot was to fill daily and hourly usage that was missing or estimated with actual data and revalidate the data for presentment to customers, 3rd parties, and downstream billing and business processes. • A pilot was run to test the ability to acquire any or all of the 30 days of hourly intervals and revalidate it in the Meter Data Management System (MDMS). Pilot planning began in 2011, and the pilot concluded in 2013. • The pilot found it would take substantial costs to upgrade systems to load and validate data faster. It was decided that the increased costs to present historic data was not cost effective based on the low number of customers who utilize this information on the web portal.
Estimated Cost of Pilot/Evaluation	• The project cost was $99,223.
Pilot/Evaluation Plan	• Implement software application changes and upgrades to the AMI systems • Implement changes to business process for validation, editing and estimation of billing and presentation data • Develop/implement required Company software and IT programming changes • Evaluate pilot results • Development of a potential implementation plan • Report results and proposed implementation plan to the Commission
High Level Benefits	• Tests the operation and performance of the meters' extended memory capabilities • Demonstrates the ability to support the on-board storage capability • Provides the ability to acquire lost data for more accurate billing information and data presentment
Potential Implementation	• Substantial system upgrade costs are needed to present historic data to customers on the web portal • On board meter storage will be an essential consideration of new AMI systems

6 C(4)
Open standards and protocols that comply with nationally recognized non-proprietary standards

Pilot/Evaluation	**In-Home Display/Home Area Network** • The objective of the pilot was to provide customers with the ability to view their real-time energy usage while they are in their home. Energy usage information was made available in power used (kilowatt hours) and also in cost (dollars). A home area network pilot trial beginning in 2012 and concluding in 2013 was conducted in order to develop the appropriate technology to meet customer requirements and expectations. The pilot incorporated IEEE 802.11 compliant wireless local area network (WLAN) communications.
Estimated Cost of Pilot/Evaluation	• The project cost was $547,664.
Pilot/Evaluation Plan	• Establish pilot objectives • Provide price and consumption information to the customer to aid in making energy efficient buying decisions • Evaluate bidirectional communications to the end-use devices • Invite customers to participate in the pilot • Provide the meter and home display hardware including any equipment installation • Develop/implement any required software and IT programming changes • Evaluate pilot results • Development of a potential implementation plan • Report results and proposed implementation plan to the Commission
High Level Benefits	• Contributes to the reduction of energy consumption through "conservation smart" automated home controls • Provides the basic hardware foundation for special rate initiatives such as critical peak pricing • Enables the customer to understand and control their energy consumption by realizing what appliances use the most electricity, the time and/or the days of the week that the most energy is consumed in their home, and other general information related to their home energy usage.
Potential Implementation	• Future implementation plans will be submitted as part of the final plan submitted in 2014.

6 C(4)
Open standards and protocols that comply with nationally recognized non-proprietary standards

Pilot/Evaluation	**AMI System Security Assessment** • PPL Electric conducted a security assessment of its AMI systems and processes. The objective was to develop a deeper understanding of AMI security and vulnerability issues as they relate to existing systems and new technologies, ensuring that customer information and metering information is protected from internal and external threats. The pilot began in May of 2013 and concluded at the end of 2013.
Estimated Cost of Pilot/Evaluation	• The project cost was $178,335.
Pilot/Evaluation Plan	• Establish pilot objectives • Conduct pilot • Evaluate pilot results • Development of a potential implementation plan • Report results and proposed implementation plan to the Commission
High Level Benefits	• Understand security risks and vulnerabilities for the current AMI system as well as any new AMI features being offered such as remote service disconnect and in home display.
Potential Implementation	• Any disclosure of the details of the findings in the final assessment would pose a security risk to PPL Electric's metering system. The final assessment was classified as 'Company Confidential' and was only available for internal review by a select group of PPL Electric employees. • Findings from the evaluation will be incorporated into future implementation plans.

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**General Obsolescence and Upgrade Issues** **Projects include:** **1. Next generation PLC-based system evaluation** **2. TWACS 20 Pilot** **3. Telecommunications Substation Modem evaluation and replacement** **4. Real Time Path mapping in PLC-based system** **5. PLC-Based System Enhancements** **6. Evaluation of Next Generation AMI Technologies** **7. Power Monitoring for Large Power Meters** • PPL Electric will conduct technological and economic evaluations that can enhance the performance of the existing AMI components as well as on next generation smart meter system technologies and Smart Grid integration. These evaluations will consider obsolescence of the communications infrastructure equipment and meters, replacement with new technology that enable PPL Electric to extend the minimum requirements and support the additional capabilities.
Estimated Cost of Pilot/Evaluation	• Project to date costs through May 2014 are $5,111,952 with total project costs estimated at $5,132,634.
Pilot/Evaluation Plan	• Evaluate the existing power line smart meter infrastructure in 2011 that extend the minimum requirements and support the additional capabilities, as well as the proposed enhancements • Evaluate Smart Grid Integration over the period from 2011 to 2014 that extend the communication infrastructure's capability to backhaul AMI/Smart Grid data more effectively • Consider additional or new smart meter infrastructure equipment to enhance data capture and accommodate new end use devices • Continually evaluate the next generation of AMI technologies for applicability at PPL Electric. • Periodically report results and potential implementation plans to the Commission.
High Level Benefits	• Effectively manage obsolescence of existing smart meter infrastructure • Positions PPL Electric for additional capabilities including Smart Grid related applications and operations • Improves efficiency in backhauling advanced meter data.
Potential Implementation	• Implementation would occur simultaneously as each technology is researched and replaced.

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**Service Limiting/Service Extending** • The pilot objective was to evaluate the technology. • PPL Electric originally intended to conduct a pilot to deploy this enhanced capability to 500 customer accounts from 2013 through 2014. Pilot planning began in 2012; however, PPL does not recommend moving forward with a pilot evaluation of the service extending functionality until technology enhancements warrant a re-evaluation. • PPL will continue to monitor the development of the technology and potential application to utility business processes.
Estimated Cost of Pilot/Evaluation	• The project cost was $7,682.
Pilot/Evaluation Plan	• N/A
High Level Benefits	• N/A
Potential Implementation	• N/A

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**Pre-pay Metering** • The objective of this pilot was to evaluate the feasibility of running a prepay program by reviewing prepay programs currently in operation throughout the U.S., and aligning the team's findings with the current PA Chapter 56 Standards and Billing Practices for Residential Utility Services. • A process was designed and a Request for Information (RFI) was issued to three Prepay vendors. PPL EU investigated the feasibility of conducting a pre-pay metering pilot based on the design, the functionality of the meters and the pre-pay vendor systems. • The pilot evaluation revealed that in the current environment it was not feasible to run a transformational pre-pay program.
Estimated Cost of Pilot/Evaluation	• The project cost was $97,773.
Pilot/Evaluation Plan	• Establish pilot objectives • Invite 500 customer to participate in pilot • Purchase and installation of meter hardware with an integrated disconnect and in-home display • Develop/implement required software and IT programming changes • Evaluate pilot results • Development of recommendations for implementation • Periodically report results and a proposed implementation plan.
High Level Benefits	• Contributes to reduction in the customer's energy consumption • Enables customers to effectively learn how to manage their electric energy payments • Enhances customer payment options • Reduces the need to dispatch personnel to disconnect and reconnect because the customer possesses the control to disconnect/reconnect safely when payment credits expire/recharged.
Potential Implementation	• The Company and all interested stakeholder should work in combination to shape a program that will best suit the needs of customers. In addition, the Company has determined that the cost to conduct a pilot will be significantly higher than estimated. Accordingly, the Company believes it appropriate to suspend its efforts on this pilot.

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**Momentary Outage Monitoring** • PPL Electric conducted a pilot from 2012 through 2013 to further refine the use of momentary interruption (blink count) information. The objective was to determine how blink information can be provided proactively to identify and correct equipment issues before the customer is impacted. This was accomplished through the aggregation of blink count data in a meaningful way to aid in determining the approximate location of the device that operated.
Estimated Cost of Pilot/Evaluation	• The project cost was $125,613.
Pilot/Evaluation Plan	• Develop and enhance business processes that actively review customer blink information • Determine the most likely location of a momentary operation • Ascertain how the customer blink information can be incorporated into PPL Electric's outage management system to refine PPL Electric's outage detection analysis and post outage restoration • Assure that automation of the processes is implemented for ease of application of the information for all business users. • Develop/implement required software and IT programming changes • Evaluate the results • Development of recommendations for potential implementation • Report results and implementation plan to the Commission
High Level Benefits	• Enables proactive messaging to Company engineers when the blink counts reach a specific threshold limit • Alerts the engineer that an issue may be occurring at the customer location or the feeder servicing that customer or group of customers • Enables engineers to take action to begin their investigation and contact the customer(s) to query if they are experiencing any issues as well as informing them that PPL Electric is working on it • Identifies and resolves device issues which have frequent momentary operations • Improves satisfaction of customers who experienced significant numbers of momentary interruptions.
Potential Implementation	• Implementation would occur simultaneously as this capability is developed and enhanced.

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**Accelerated Supplier Switching** • The objective of this project is to enable customers to switch suppliers more quickly than the current supplier switching rules. • The acceleration of supplier switching will be implemented in accordance with the guidance from the Retail Market Investigation. • On 4/3/2014, Rulemaking to Amend the Provisions of 52 PA Code, Chapter 57 Regulations Regarding Standards for Changing a Customer's Electric Generation Supplier (Final-Omitted Rulemaking Docket L-2014-2409383) was issued. The Company is moving forward with the planning and implementation of off cycle supplier switching; however, based on the Final-Omitted Rulemaking and the time constraints laid out there in, future work on this project will be outside of the Smart Meter Plan.
Estimated Cost of Pilot/Evaluation	• The project cost was $20,100.
Pilot/Evaluation Plan	• Develop scope, costs and detailed schedule • Work with key stakeholders and Retail Market Investigation • Evaluate all impacted systems • Develop new procedures and processes • Develop training and documentation for customer service • Implement in accordance with final guidance from Retail Market Investigation
High Level Benefits	• Improve customer satisfaction and development of retail markets by allowing off-cycle switching (limited to one off-cycle switch per month).
Potential Implementation	• Based on the 4/3/2014 Final-Omitted Rulemaking and the time constraints laid out there in, future work on this project will be outside of the Smart Meter Plan. The Company will further define the project scope, and schedule resources to ensure consistency with the final direction from the Retail Markets Investigation.

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**Supplier Portal Pilot** • The objective of this project was to pilot and evaluate an alternative method of providing large amounts of energy usage and interval data to suppliers through a secure portal. • The project involved creating a secure data environment wherein EGSs, and potentially other third parties, can, with appropriate customer authorization, access usage data directly without need for an EDI request and response • PPL is also participating in the EDEWG WPWG (Web Portal Working Group) Sub Team as the EDC Chair, and is expecting the Sub Team to provide recommendations which will ultimately steer the continued development of the Supplier Portal through 2014.
Estimated Cost of Pilot/Evaluation	• Project to date costs through May 2014 are $558,580 with total project costs estimated at $579,813.
Pilot/Evaluation Plan	• Develop scope, costs and detailed schedule • Work with key stakeholders to develop standards • Develop processes and procedures • Create a secure data environment, wherein EGSs, and potentially other third parties, can access usage data directly without the need for an EDI request and response
High Level Benefits	• Direct access to customer meter data in a more timely manner • Secure data environment • More efficient than the current EDI system • Less expensive than the current EDI system
Potential Implementation	• The first deployment of the supplier portal was released to production and suppliers in May 2013 • The second release was completed in January 2014 and is currently awaiting PUC approval

6 C(5)
Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible

Pilot/Evaluation	**MDM Data Warehouse and Analytics** • The objective of this project is to copy customer and meter data into a data warehouse (i.e., non-production) environment to improve PPL Electric's MDMS operations and analytical capability to support suppliers and customers. • This project was delivered in two phases. Phase 1 included evaluation of data warehouse appliances, vendor selection, implementation and replication of meter data onto the data warehouse appliance and was completed in 2013. • Phase 2 scope included conceptual data warehouse architecture, replication of customer data and future state meter and customer analytic use cases defined. Phase 2 was completed in March, 2014
Estimated Cost of Pilot/Evaluation	• The project cost was $2,003,047.
Pilot/Evaluation Plan	• The Company would take a phased approach to the project. • 2012 - Phase 1 - Install all required software and hardware for the meter data warehouse to improve the speed to run reports and queries • 2013 - Phase 2 - Solidify business analytics data needs and architecture, upon which a future solution could be built.
High Level Benefits	• Ad-hoc querying capability • Improve MDMS operational performance • Enhance PPL Electric's ability to provide smart meter data to customers and EGSs. • Improve ability to perform better analysis of meter data to better serve customers
Potential Implementation	• As business lines become more familiar with the data available in the data warehouse for operational analytics it is believed standardized reports and alerts will be used to proactively identify anomalies, such as: system and equipment issues as well as usage patterns identifying possible theft of service

6 C(6)
Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information

Pilot/Evaluation	**Projects include:** **1. Site Scan Enhancement in wireless-based system** **2. Voltage Monitoring in PLC-based system** • In 2010, PPL Electric began implementing an enhancement that applies more precise voltage, current and relational phase angle information from the Company's large power meters for diagnosing meter and service issues. This enhancement was implemented in 2011 for the large power meters. • A pilot was conducted from 2011 through June of 2013 to further the measurement, collection and analysis of voltage information to enhance PPL Electric's distribution system reliability using the power line AMI system. The work scope identified for this pilot has been completed and is being transitioned to production.
Estimated Cost of Pilot/Evaluation	• Large power meter information enhancement – The project cost was $142,672. • PLC based pilot – The project cost was $259,471.
Pilot/Evaluation Plan	• Determine the feasibility of gathering this new information by performing an impact analysis on the AMI to ensure there are no performance issues • Export the data collected into a meter data management system which provides a facility for engineers to access and apply the data in business applications • Develop/implement required software and IT programming changes • Establish and report results and implementation plan to the Commission.
High Level Benefits	• Application of voltage profiling information at a customer, transformer and circuit level will provide information on the health of an entire circuit • Use of this information will alert PPL Electric to customer voltage problems, thereby increasing customer satisfaction by correcting voltage issues on a proactive basis • Applications of voltage, current and relational phase angles information will proactively aid identification of defective metering equipment to avoid revenue loss • Will provide pertinent information to a smart grid strategy that will enable PPL Electric to reduce voltage when needed to maintain distribution system reliability • Will provide a framework for an accurate operational model, which will provide faster customer restoration, and more efficient system utilization.
Potential Implementation	• Implementation of the PLC-based and wireless-based pilots would occur simultaneously as the capability is developed and enhanced. • Availability of site scan data will be a consideration in new AMI systems.

6 C(7)
Ability to remotely reprogram the meter

Pilot/Evaluation	• PPL Electric will be evaluating ways to continue refining the power line smart meter infrastructure's remote programming capabilities. These evaluations are associated with the work described in Section 6C(5).
Estimated Cost of Pilot/Evaluation	• The costs to complete these evaluations are included in Section 6C(5).
Pilot/Evaluation Plan	• Demonstrate enhanced ability to reprogram meters • Upgrade the system's equipment firmware to improve performance • Consider potential equipment hardware upgrades to accommodate enhanced functionality. • Reporting results and implementation plans to the Commission.
High Level Benefits	• Benefits are similar to that described in Section 6C(5).
Potential Implementation	• Embedded in that described in Section 6C(5).

6 C(8)
Ability to communicate outages and restorations

Pilot/Evaluation	**Proactive Outage Detection** • The objective of the pilot was to determine the system-wide feasibility of using the power line system for proactive meter outage detection for the purpose of distribution system health checks and active outage detection. This was done by proactively pinging customer meters on a selective basis to determine the extent of an outage prior to customers calling in to provide similar outage extent and device information. • The pilot was conducted in 2012 and evaluated the use of substation breaker data to identify drops in electric usage.
Estimated Cost of Pilot/Evaluation	• The project cost was $166,268.
Pilot/Evaluation Plan	• Establish pilot objectives • Demonstrate improvement in the accuracy of existing pings through the investigation and mediation of performance issues • Integrate SCADA data to proactively "ping" customers' meters to assess service status • Optimize "ping" services to more actively assess outage conditions and dispatch personnel where required • Reporting results and implementation plan to the Commission.
High Level Benefits	• Implements proactive pinging of customers' meters to determine their outage status will help reduce outage times for customers, specifically for smaller outages, or outages where a customer would not normally report that they are out of service • Ability to know outage types and locations will more quickly allow PPL Electric to report that information to customers who do call in • Will provide a framework for more quickly performing proactive outage notification feature in the future for customers to elect that option.
Potential Implementation	• This automatic analysis of electric usage drops needed to identify the differences between outages and normal operational distributions switches. Testing the automation revealed that customer calls regarding electric outages were faster than the automated analysis. The limitations in this process make it less effective than customers calling in, so there will be no further implementation.

6 C(8)
Ability to communicate outages and restorations

Pilot/Evaluation	**Outage Duration** • The objective of the Outage Duration Pilot was to demonstrate the ability of PPL's AMI system to retrieve outage information from solid state meters and incorporate this data into field engineering operations for outage analysis. As a result of the pilot PPL EU has provided a tool to operations that provides the actual start and stop dates of outages which can be used for outage correction processes.
Estimated Cost of Pilot/Evaluation	• The project cost was $112,899.
Pilot/Evaluation Plan	• Establish pilot objectives, cost and detailed schedule • Demonstrate ability to retrieve outage duration information from meters • Develop analysis tools • Determine how to use the information in the meter data validation and outage management processes.
High Level Benefits	• Improved power quality analysis and customer service • Improved VEE process • Retrieve sustained outage information from meter module for validation and fine-tuning of outage data
Potential Implementation	• The pilot was successful; PPL Electric has implemented the use of meter outage duration data in the outage correction process.

6 C(9)
Ability to support net metering of customer generators

Pilot/Evaluation	**Customer-Owned Generation** • The objective of this pilot was to test the functionality and performance of new bi-directional meters in the power line carrier (PLC) system to measure net energy flow at generation customer's point of connection (meter). • The pilot consisted of installing 400 bi-directional solid state Focus UMT AL meters in the PLC system to measure net interval energy usage flowing in and out of premises with renewable energy. The pilot customers were existing net metering customers with older vintage meters. • The pilot found the net energy registration to work as designed, and as a result all residential customers with installed generation were provided a solid state bi-directional meter for the pilot. • As of May 9th 2014 PPL EU has installed net metering on 3127 customers with generation connected.
Estimated Cost of Pilot/Evaluation	• The actual cost of the pilot and implementation was $262,295.
Pilot/Evaluation Plan	• Identify approximately 400 existing net metering customers and replace their meter to the new standard power line meter • Meter hardware and installation • Develop/implement required software and IT programming changes for the AMI and MDMS • Evaluate pilot results • Establish an implementation plan • Report results and implementation plan to the Commission.
High Level Benefits	• Supports the functional operation and performance capabilities of the power line smart meter infrastructure and bi-directional meters • Meets the intent of the Commission's Net Metering tariffs • Provides a feasible and economical meter solution to monitor AEPS renewable energy requirements through measurement of the generation output of applicable generation sources.
Potential Implementation	• Implementation was completed and fully supports net metering for customers with installed generation. This includes a process to ensure correct metering is installed following notification of customer's intention to install generation.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation
For Approval of Its Smart Meter
Technology Procurement and Installation Plan

Docket Nos. P-2014-__________
and M-2009-2123945

Direct Testimony of Dennis A. Urban, Jr.

Date: June 30, 2014

Direct Testimony of Dennis A. Urban, Jr.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis A. Urban, Jr. My business address is Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. On whose behalf are you providing direct testimony in this proceeding?

A. I am providing Direct Testimony on behalf of PPL Electric Utilities Corporation ("PPL Electric" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Electric, a subsidiary of PPL Corporation, as Vice President, Finance and Regulatory Affairs.

Q. What are your duties as Vice President, Finance and Regulatory Affairs?

A. I have overall responsibility for PPL Electric's financial functions as well as Federal Energy Regulatory Commission ("FERC") and Pennsylvania Public Utility Commission ("Commission") jurisdictional regulatory matters.

Q. What is your educational background?

A. I have an Associate degree in Electrical Technology from the Dean Institute of Technology, a Bachelor of Science degree in Accounting from Point Park University, and a Master of Business Administration degree from Robert Morris University.

Q. Please describe your professional experience.

A. In 1982, I began my career with Duquesne Light Company ("Duquesne"), a Pittsburgh, PA based electric utility. Through 1996, I held various bargaining unit operations and maintenance positions, including certification as a journeyman lineworker. In 1997, I moved into a management role in the accounting department where I held the position of Senior Accountant until May 1999. From June 1999 to October 2001, I held the position of Manager of Financial Reporting where I had responsibility for all internal and external financial reporting requirements. In November of 2001, I was transferred to Duquesne's parent company, DQE, Inc., as the Manager of Corporate Development where I had responsibility for the development and recommendation of strategic alternatives. In May of 2004, I was promoted to Director of Corporate Development with the additional responsibility for the development of a strategic energy sourcing strategy to fulfill Duquesne's default service obligation. In June 2007, after Duquesne was purchased by a group of private equity investors, I became Manager, Financial Planning and Risk Analysis where I had responsibility for Duquesne's budgeting, planning and financial forecasting functions as well as its risk management functions including internal audit and corporate insurance programs. I joined PPL Electric in November 2008 as Manager, Energy Acquisition where I had responsibility for the development and implementation of the functional requirements to fulfill its default service obligation. In November 2010, I assumed the role of Senior Director, Rates and Regulatory Affairs. In January 2013, I was promoted to my current role as Vice President, Finance and Regulatory Affairs.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an overview of the Company, its existing metering system and its proposed Smart Meter Plan ("SMP").

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Section I of PPL Electric Exhibit No. 1, Executive Summary of PPL Electric's Smart Meter Technology Procurement and Installation Plan ("SMP").

Q. Please describe the direct testimony submitted by the Company in this proceeding.

A. In addition to my direct testimony, the Company has also submitted the direct testimony of the following witnesses that will explain the subject matters that are listed:

- David R. Glenwright (PPL Electric Statement No. 2)

- Background of PPL Electric's Current AMI System
- Pilot Programs
- Technology Assessments
- Implementation Plan
- SMP Benefits

- Jason Kinslow (PPL Electric Statement No. 3)
  - Technical Assessment
  - SMP Systems
- Christine E. Ogozaly (PPL Electric Statement No. 4)
  - Financial Overview
  - Vendor Selection Process
  - Organizational Impacts
  - Program Risks
- Kent Simendinger (PPL Electric Statement No. 5)
  - Cyber Security and Data Privacy
- Bethany L. Johnson (PPL Electric Statement No. 6)
  - Cost Recovery

BACKGROUND

Q. Please explain PPL Electric's operations.

A. PPL Electric provides electric distribution and transmission services to approximately 1.4 million customers in a certificated service territory that spans approximately 10,000 square miles in all or portions of 29 counties in eastern and central Pennsylvania. PPL Electric also provides default generation service to customers that have not selected an electric generation supplier ("EGS"). PPL Electric operations are subject to the jurisdiction of the Commission.

Q. Does PPL Electric currently have an advanced metering system?

A. Yes. PPL Electric was among the first investor-owned utilities in the country to implement an automated metering system. In 2002, the Company began deploying its existing automated meter reading system, which consisted of meters, communications infrastructure, computer services and Information Technology ("IT") applications that allowed the Company to remotely read the meters of all of its 1.4 million customers through communications over the power lines. PPL Electric is able to read all of its meters on an hourly, daily or monthly basis. As a result of this technology, PPL Electric eliminated its meter reader positions and further reduced its workforce, including service personnel and customer service representatives. The savings generated from implementing this advanced metering technology have been flowed through to customers in PPL Electric's subsequent base rate proceedings.

Beginning in 2005, PPL Electric installed a Meter Data Management System ("MDMS") to support processing of meter data being collected from the system to directly interface with a customer portal known as the Energy Analyzer. Through the Energy Analyzer, customers can see their hourly energy usage and utilize tools to help them analyze and better understand their electricity usage and bills.

Q. Does PPL Electric's existing metering system meet the smart meter requirements under Act 129 of 2008?

A. No. The Company's existing metering system is not able to effectively provide customers with direct access to price and consumption information as is required by Act 129, 66 Pa. C.S. § 2807(g). In addition, PPL Electric's existing system is limited in its ability to provide 15-minute interval data. Moreover, PPL Electric would be required to replace nearly all of its meters in order to provide additional capabilities that are set forth in the Commission's Smart Meter Implementation Order, including remote disconnect/connect capability. *Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, Implementation Order entered June 24, 2009 ("*Implementation Order*").

Q. Is the Company's current metering system nearing the end of its useful life?

A. Yes, as explained in more detail by Mr. Glenwright, PPL Electric Statement No. 2, the Company is experiencing a meter failure rate that is four times the industry standard driven by the age of the current metering technology.

Q. Is the Company proposing to replace its current metering system?

A. Yes, due to the reasons I explained above as well as the reasons provided in the SMP, the Company is proposing to replace its existing Power Line Carrier ("PLC") metering system with a Radio Frequency ("RF") Mesh system that will fully comply with Act 129 and the additional capabilities set forth in the Commission's *Implementation Order*.

SMART METER PROGRAM OVERVIEW

Q. What steps has the Company taken in developing its SMP?

A. As explained in more detail by Mr. Glenwright, the Company has performed an extensive evaluation of its existing metering system through numerous pilot programs. Several of these pilot programs demonstrated that a PLC system was limited in its ability to fully meet the requirements of Act 129 and the *Implementation Order*. PPL Electric also hired IBM to assist the Company in evaluating smart meter systems that are being used by other utilities across the country.

Q. What type of smart meter systems has the Company evaluated?

A. The Company evaluated the predominant types of AMI technology for communicating with its meters including PLC technologyand radio frequency (RF) systems. Additionally, two types of radio frequency systems were evaluated, a point-to-multipoint and an RF mesh. Point-to-multipoint systems typically have a central gateway to a number of (meters). This gateway could be a communications tower. A mesh system allows communication paths to weave together. Meters, repeaters and collectors may all be part of the communication network.

Q. Based upon these evaluations, what type of smart meter system is the Company proposing to implement?

A. The Company is proposing to implement an RF Mesh AMI system. An RF Mesh system will be able to meet Act 129 and the Commission's *Implementation Order* requirements. Moreover, since 2002, several large utilities in North America have chosen to deploy RF Mesh systems and have developed best practices and lessons learned from these deployments. PPL Electric intends to collaborate with these utilities to learn from their experiences when implementing its RF Mesh system. For additional details, please see PPL Electric Statement Nos. 2 and 3, the Direct Testimonies of Mr. Glenwright and Mr. Kinslow, and Section III of the SMP.

Q. Has the Company developed a proposed deployment schedule for implementing the SMP?

A. Yes. Upon Commission approval, the Company proposes to install the Information Technology ("IT") system upgrades that will be necessary for the new system. These IT system upgrades are projected to be completed in 2016. Deployment of meters will be conducted in three phases. The first phase will be a solution validation phase, which will consist of the installation of approximately 50,000 meters beginning in late 2016 through 2017. The purpose of this phase is to allow for testing and fine tuning of the metering and communication network prior to full deployment. The second phase is the full deployment phase which will begin in 2017 through 2019. During this phase, the Company will fully deploy

RF Mesh meters throughout its service territory. The third phase is a two-year stabilization period during 2020 and 2021, which will be used to continue fine-tuning the mesh network and back office systems and deploying final system enhancements or upgrades. Please see Section V of the SMP for additional details.

Q. What are the Company's estimated costs for implementing its SMP?

A. The Company estimates that the costs of implementing the SMP will be approximately $450 million. This includes estimated costs for meters, network and network management costs, IT costs, Systems Integration costs, Program Management costs and Communications/Change Management costs. Additional details regarding these cost categories are provided in Section X of the SMP.

I note that the estimated costs set forth in the plan are high level estimates that are subject to change for a variety of reasons. PPL Electric proposes to recover its actual costs for implementing the SMP.

Q. How does PPL Electric propose to recover its SMP costs?

A. PPL Electric proposes to recover its SMP costs through its Smart Meter Rider ("SMR"). PPL Electric currently has a SMR in place to recover the costs of implementing its Smart Meter pilot programs. PPL Electric is proposing to utilize the SMR, with several modifications, to recover costs for implementing this SMP. Additional details are provided in Section XII of the SMP and in the Direct Testimony of Ms. Johnson, PPL Electric Statement No. 6.

Q. Will the Company address cybersecurity and data privacy issues associated with the SMP?

A. Yes, the Company has a team of cybersecurity and data privacy experts that will address these issues. Additional details are provided in Section VI of the SMP as well as the Direct Testimony of Mr. Simendinger, PPL Electric Statement No. 5.

Q. Has the Company evaluated Organizational Impacts and Program Risks that may result from the SMP?

A. Yes, the Company has evaluated and will continue to evaluate Organizational Impacts that may result from the SMP. The Company also is evaluating risks associated with implementing the SMP and taking steps to mitigate potential risks. These issues are discussed in Sections VII and VIII of the SMP and also in the Direct Testimony of Ms. Ogozaly, PPL Electric Statement No. 4.

Q. Does the Company anticipate that the SMP will provide benefits to customers?

A. The Company does anticipate that the SMP will provide benefits to customers. As noted above, the Company has eliminated its physical meter reading force with the implementation of its existing PLC AMI System. Customers have already received these cost savings in the Company's base rate proceedings. However, the Company anticipates additional benefits from implementing the SMP, including reduced operations costs with the remote connect/disconnect functionality, reduced call center volume, improved power quality and improved outage management processes. The anticipated benefits are further described in Section IX of the SMP and in the Direct Testimony of Mr. Glenwright, PPL Electric Statement No. 2.

Q. Has the Company developed a communication strategy for the SMP?

A. Yes, the Company has provided details for how it will educate customers and other interested parties about the SMP. These details are discussed in Section XI of the SMP and in the Direct Testimony of Ms. Ogozaly, PPL Electric Statement No. 4.

Q. Why do you believe that the Company's proposed SMP is a reasonable plan?

A. The Company's SMP is a prudent plan that will fully meet all of the smart meter requirements of Act 129 and the additional requirements set forth in the Commission's *Implementation Order*. Under the SMP, PPL Electric will replace its aging PLC System with advanced technology that will provide customers with additional tools to manage energy usage and provide the Company with additional tools to improve service and power quality. I note that all major EDCs in Pennsylvania are proposing to provide smart meter technology to customers through an RF based technology. Additional reasons in support of the SMP are provided in the testimony of PPL Electric's witnesses and in the SMP.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

PPL Electric Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation For Approval of Its Smart Meter Technology Procurement and Installation Plan

Docket Nos. P-2014-__________
and M-2009-2123945

Direct Testimony of David R. Glenwright

Date: June 30, 2014

Direct Testimony of David R. Glenwright

INTRODUCTION

Q. Please state your full name and business address.

A. My name is David R. Glenwright. My business address is 827 Hausman Road, Allentown, PA 18104.

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Electric Utilities Corporation ("PPL Electric" or "the Company") as the Advanced Metering Development Project Manager.

Q. What are your qualifications, work experience and educational background?

A. I have 27 years of experience working in the utility industry in various engineering and management roles. I joined PPL Electric in 2009 and held several management positions in contractor management, pole attachments, and work management. I currently serve as Advanced Metering Development Project Manager for PPL Electric. In this role I have responsibility for developing overall AMI strategies, plans, and implementing various projects in support of Pennsylvania Act 129 Smart Meter regulations. Prior to PPL Electric, I worked for PECO / Exelon for 22 years in various roles, including operating PECO's AMR system and evaluating the use of new metering technology and applications across Exelon. I also supported the development of PECO's smart meter plan. I have a Master of Business Administration and Bachelor of Science in Mechanical Engineering degrees from Drexel University.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission")?

A. No.

Q. What is the purpose of your testimony?

A. My testimony will provide background on PPL Electric's current AMI system, summarize the pilot programs and discuss the technology assessments that PPL Electric conducted in order to develop and file its Smart Meter Technology Procurement and Implementation Plan ("SMP"). In addition, I will provide information about the implementation plan, and the benefits of both the current AMI system and the one proposed in the SMP.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Section II. PPL Electric Background, parts of Section III. Technology Assessment, Section V. Implementation Plan, and Section IX. Program Benefits of PPL Electric's SMP (PPL Electric Exhibit No. 1).

BACKGROUND

Q. Please summarize the smart meter requirements mandated by Act 129.

A. Act 129 requires electric distribution companies ("EDCs") with greater than 100,000 customers to implement smart meter technology. Smart meter technology is defined as having the following capabilities:

- Bidirectional data communications;

- Reading usage data on at least an hourly basis once per day;
- Providing customers with direct access to and use of price and consumption information;
- Providing customers with information on their hourly consumption;
- Enabling time of use ("TOU") and real time pricing ("RTP") programs.
- Supporting the automatic control of the customer's electric consumption.

Q. Has the Commission provided additional requirements for smart meter technology?

A. Yes, the Commission's Smart Meter *Implementation Order*[1] stated nine additional required capabilities:

- Ability to remotely disconnect and reconnect;
- Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties, and an RTO on a daily basis, consistent with the data availability, transfer, and security standards adopted by the RTO;
- On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables;
- Open standards and protocols that comply with nationally recognized non-proprietary standards such as IEEE 802.15.4;
- Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible;

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[1] *Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, *Implementation Order* entered June 24, 2009.

- Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information;
- Ability to remotely reprogram the meter;
- Ability to communicate outages and restorations;
- Ability to support net metering of customer-generators.

In addition to these requirements the Commission, in December 2012,[2] ordered EDCs to provide capability for:

- Utilization of smart meter data for bill ready and dual billing,
- Providing at least 12 months of account or meter level historical interval usage data via Electronic Data Interchange ("EDI"),
- Participating in an Electronic Data Exchange Working Group ("EDEWEG") to define a solution for providing hourly billing quality interval usage data via a web portal,
- Providing a plan to support meter level hourly interval usage data.

Q. Does PPL Electric currently have an automated meter system?

A. Yes. PPL Electric was one of the first investor-owned utilities in North America to deploy an Automated Metering Infrastructure ("AMI") system-wide. Deployment of this AMI solution began in 2002, utilizing a Power Line Carrier ("PLC") technology from Aclara, wherein data from meters is transmitted via the existing power line infrastructure. The deployment of the automated meters (approximately 1.4 million) was completed in 2004. A Meter Data Management

[2] *Smart Meter Procurement and Installation,* Docket No. M-2009-2092655, Final Order entered December 6, 2012.

("MDM") system was added in 2006 to support processing of the meter data being collected from the AMI system and to interface directly with a customer portal, which provides customers access to view and analyze their energy usage. As a result, PPL Electric was one of the first utilities in the country to present hourly usage data to all customers. Additionally, for large commercial and industrial customers, the Company has a cellular based automated meter system using Itron's MV-90 system.

Q. Did PPL Electric file an Initial Smart Meter Plan with the Commission?

A. Yes. In 2009, PPL Electric submitted its initial Smart Meter Filing as required by the Commission describing compliance with Act 129 and the Commission's subsequent Smart Meter *Implementation Order*.

Q. Did the Commission approve the Company's initial smart meter plan?

A. Yes, but with conditions. The Commission approved the pilot programs included in the SMP, but determined that PPL Electric's current AMI solution was not fully compliant with all legal and regulatory requirements. In particular, the Commission cited the inability of the Company's solution to provide direct access to and use of pricing information, and the need for further evaluation regarding the 15-minute interval data requirement.

Q. What steps did the Company take after the Commission's June 24, 2010 Order?

A. Following the Commission's Order, PPL Electric undertook a series of pilot programs to evaluate the abilities of the Company's current Aclara PLC system, as well as the impact of upgrades and extensions to the PLC AMI solution in order to meet Act 129 requirements. The status of these pilots was reported to the Commission on an annual basis.

PPL Electric also contracted with industry leading smart meter consultants, such as Black & Veatch and IBM, to assist in various aspects of its smart meter plan development.

Q. Did the Company make any additional filings?

A. On May 4, 2012, the Company filed a petition requesting approval to modify its Smart Meter Plan and to extend its grace period to give the Company additional time to further test and evaluate the most cost-effective ways to meet the Act 129 requirements (*Petition of PPL Electric Utilities Corporation for Approval to Modify Its Smart Meter Technology Procurement and Installation Plan and to Extend its Grace Period, Docket No. P-2012-2303075* ("May 2012 Petition")).

In its Order entered August 2, 2012, the Commission granted an extension until June 30, 2014 for the Company to file its Final Smart Meter Plan and approved additional pilots the Company requested to complete its assessment.

PPL Electric has filed annual updates regarding progress on its SMP since submitting its initial filing in 2009, and has conducted multiple stakeholder meetings to provide updates on the progress of pilot programs and other matters of importance related to the SMP. Representatives from the Office of Consumer Advocate ("OCA"), Pennsylvania Utility Law Project ("PULP"), PP&L Industrial Customer Alliance ("PPLICA"), Reliant Energy, PA Coalition Against Domestic Violence, various Commission representatives, and other interested parties attended one or more of these stakeholder meetings.

The Company will continue to provide annual smart meter plan updates and meet with interested stakeholders on a regular basis and support ad-hoc updates as necessary and appropriate.

Q. What analysis has the Company performed to determine whether its existing metering system will meet the Act 129 requirements?

A. PPL Electric has conducted two sets of activities to determine if the existing metering system will meet Act 129 requirements. First, the Company has conducted numerous pilot programs aimed at proving out the impact of upgrades to the existing metering system. Based on these pilots, PPL Electric concluded that the existing PLC AMI solution is technically limited in its ability to fully comply with legal, regulatory, and future business requirements.

Additionally, the Company contracted with industry leading smart meter consultants, such as Black & Veatch and IBM, to assist in various aspects of its smart meter plan development. Black & Veatch assisted the Company in determining the technical limitations of the existing PLC AMI solution. Black & Veatch also assisted in the assessment of the existing MDM and competing products in the marketplace. Requests for Information ("RFI") were issued for the MDM assessment to solicit technical and cost information.

In July 2013, PPL Electric contracted with IBM to assist in the development of its smart meter vision and plan, and perform a detailed market assessment of advanced metering technology. RFIs were issued to solicit vendor technical and cost information from the marketplace. Additional activities supported by IBM include developing the SMP and supporting cost model.

Additional assessments of metering infrastructure including the Meter Asset Management System ("MAM"), customer energy portal, and smart meter network operating center software ("NOC"), were also conducted by the Company.

Q. Please provide additional details regarding the conclusions the Company reached as a result of its analysis.

A. The assessments and pilots led to several conclusions:

- The existing PLC AMI solution is not fully compliant with the legal and regulatory requirements. PPL Electric's current PLC AMI solution consists of two related but different vintages of meters for residential and small commercial customers. Approximately 86% of the total existing meter population consists of 2002 vintage electromechanical meters retrofitted with a first generation PLC communication module. The remaining 14% consists of upgraded solid-state electronic meters with a newer vintage PLC communication module. Neither type of meter complies with all of the Act 129 and *Implementation Order* requirements.

The 2002 vintage electromechanical meters, consisting of 86% of the meter population, do not meet eight of the fifteen requirements including: (1) providing customers with direct access to and use of price and consumption information, (2) remote connect / disconnect, (3) providing 15-minute or shorter interval data, (4) supporting on-board storage of meter data, (5) supporting open standards and protocols, (6) ability to upgrade minimum capabilities, (7) ability to remotely reprogram the meter, and (8) net metering of customer generators.

The upgraded solid-state electronic meters also do not comply with all Act 129 and *Implementation Order* requirements. Specifically, the upgraded meters are unable to effectively provide customers with direct access to and use of price and consumption information. In addition, bandwidth constraints over the Company's PLC system limit the ability to fully provide 15-minute or shorter interval data.

- Market assessments and pilot programs conducted by the Company validated the increasingly declining market presence of PLC technology and supporting metering systems, which was determined to be limited in both scalability and functionality versus competing AMI technology types and supporting systems. This inability to keep pace with the marketplace also meant that without a new solution, PPL Electric would be unable to provide the same level of service to its customers as could be provided by peer utilities.

Q. In addition to being unable to meet the smart meter requirements, is the Company's existing metering system nearing the end of its useful life?

A. Yes. A typical mature meter population experiences a low failure rate during the asset life of the meter. An industry standard failure rate for a meter population during its useful life is approximately 0.5%. For PPL Electric's population of 1.4 million meters, a failure rate consistent with the industry standard would realize approximately 7,000 meter replacements per year. PPL Electric experienced approximately 28,000 failed meters in 2013, or approximately four times the industry standard.

Q. Based upon the analysis you describe above, what type of smart meter technology is the Company proposing to implement?

A. As a result of the extensive pilots and assessments, PPL Electric is proposing to implement a Radio Frequency Mesh ("RF Mesh") AMI technology type for its future smart metering solution. The Company is also proposing to replace and add supporting systems needed to enable advanced metering functionality including the Head End system, the MDM, the MAM, the Customer Portal, the smart meter NOC and the associated IT architecture. Please see PPL Electric Statement No. 3, the Direct Testimony of Mr. Kinslow, for a description of these systems.

The Company is also evaluating its Customer Information System ("CIS") to determine if it can support recently passed accelerated supplier switching regulations. If the Company determines that modifications are needed to the

CIS, an amendment to this SMP will be filed to seek cost recovery of the CIS changes.

Q. Did the Company select vendors for the RF mesh AMI solution?

A. No, the Company has not selected vendors at this stage. The vendor selection process will be conducted in the second half of 2014 as described in Ms. Ogozaly's testimony.

IMPLEMENTATION PLAN

Q. Please explain the Company's proposed schedule for implementing smart meter technology.

A. PPL Electric proposes to deploy its upgraded advanced metering infrastructure from 2015 through 2021. This deployment will include the building of back office IT systems, lab and field testing, a controlled solution validation phase, and a full deployment phase (2017-2019) during which all current meters will be replaced. The deployment will be followed by a 2-year stabilization period to optimize system operation.

Additionally, following the end of the stabilization period in 2021, the Company will continue investigating advanced functionality beyond the 15 requirements mentioned above, including furthering advanced analytical capabilities and identifying synergies with its distribution automation (DA) network.

Q. Why is the Company adopting a phased approach for implementing smart meter systems?

A. PPL Electric plans a phased approach to coincide with the components of the deployment previously described. A staged approach will reduce risk associated with the implementation of a new technology, and will provide PPL Electric with the ability to validate components of the technology as they are deployed. Additionally the phased approach, especially during the build out of the IT infrastructure, will enable the Company to continue to operate its existing systems as it deploys the new technology. This is critical to ensure customer service levels are maintained for existing PLC metered customers as well as those with the new smart meter technology.

Q. Is the Company phasing in smart meter functionality for customers?

A. Yes. At the start of full deployment in 2017, the installed meters will have the following capabilities:

- Bidirectional data communications;
- Recording of usage data on at least an hourly basis once per day, and providing customers with information on their hourly consumption;
- Support of Time-Of-Use and Real-Time-Pricing;
- Ability to provide 15-minute or shorter interval data to customers, EGS's, third-parties, and an RTO on a daily basis, consistent with the data availability, transfer, and security standards adopted by the RTO. Initially, this will be provided for the large industrial and commercial customers as we provide today;

- Remote Service Switch capability;
- On-board Meter Storage of Meter Data that complies with the nationally-recognized non-proprietary standards;
- Open standards and protocols that comply with the nationally-recognized non-proprietary standards;
- Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible;
- Remote programming capability;
- Ability to communicate outages and restorations for ping and power restoration;
- Ability to support net metering of customer generators.

In the middle stages of deployment, when the increasing quantity of meters provides a robust network, the following capabilities will be enabled:

- Ability to monitor voltage at each meter and report in a manner that allows an EDC to react to the information;
- Ability to communicate outages and restorations using last gasp and power restoration messages.

Near the end of the deployment, additional capabilities will be enabled:

- Providing customers direct access to consumption and pricing information;
- Ability to provide 15-minute or shorter interval data. During this stage we will evaluate the need to enable this capability for small commercial and residential with recognition that elements of our IT hardware and architecture will require upgrading if the need exists;
- Support Automatic Load Control by EDC.

Q. Why is the phased approach necessary?

A. It is necessary from both a technical and business change management perspective. The technical nature of AMI RF mesh networks requires a certain area saturation point to allow for multiple routing options. This enables network optimization and a self-healing network, which in turn allows for the full functionality of the meters to be utilized. From a change management perspective, the Company will be implementing various process changes and needs to carefully stage that work to effectively implement the changes.

Q. Please describe PPL Electric's plan to address watthour meter testing during full deployment?

A. PPL Electric will address in-service and removed watthour meter testing during full deployment in years 2017 to 2019 as follows. For periodic in-service testing of watthour meters, the Company will appropriately adapt its current sample process to ensure that in-service testing continues to meet or exceed the requirements contained in 52 Pa. Code § 57.20(e).

Regarding the testing of removed watthour meters during fully deployment, the Commission's Implementation Order exempted all electric distribution companies required to install smart meter technology from compliance with 52 Pa. Code § 57.20(h), which states, "A service watthour meter which is removed from service shall be tested for "as found" registration accuracy." Nevertheless, the Company will implement a "Deployment Sample Process" to identify a statistically significant random sample of removed meters.

This sample of removed meters will be flagged for registration accuracy testing and returned to the Company's meter test lab as they are removed from service by the deployment vendor.

Additionally, PPL Electric will hold all removed meters for two billing cycles before allowing them to be retired. This will allow any customer billing concerns to be addressed and provide the ability to locate the stored meter for accuracy testing.

PROGRAM BENEFITS

Q. Has the Company already experienced benefits from installing an automated metering system?

A. Yes. PPL Electric is different from many other EDCs in that it already has an AMI solution that delivers some of the customer benefits required by Act 129 and the Commission's *Implementation Order*. For example, customers already benefit by having access to hourly energy usage information, they receive very few estimated bills due to the high meter reading performance of the existing system, and the newer generation solid-state PLC meters support net generation and remote connect / disconnect.

The most significant benefit achieved from the current system was from the elimination of physical meter reading operations for all of its electric customers as well as associated meter reading support equipment, vehicles, and systems. The Company also realized benefits from improved reliability in customer billing and outage management. Additionally, the projects that PPL

Electric has been piloting and implementing to enhance its PLC metering system have delivered their own benefits. Some of these pilots, such as remote connect/disconnect, voltage and momentary monitoring, and validating outage durations have been implemented and are providing benefits by enhancing operations, outage management and customer service, albeit on a limited basis. Other pilots that were implemented, such as developing a supplier portal, providing customers with price and usage information, and implementing a meter data management warehouse and analytics platform have improved the Company's ability to provide information to customers and suppliers.

Q. Have customers realized the benefits of the automated meter reading system?

A. Yes. The operational savings have been reflected in PPL Electric's base rate proceedings.

Q. Will the Company realize additional benefits associated with installing the new SMP?

A. Yes. The proposed Smart Meter Deployment Plan will provide a foundation to realize future customer and operational benefits. Expected benefits include reduced meter services support, decreased call center volumes, improved outage management, improved identification and cost recovery of unaccounted-for energy.

In the area of meter services, the proposed AMI solution will include remote connect / disconnect switch functionality that will reduce the number of physical visits associated with voluntary and involuntary service reconnections and terminations. The Company will use this functionality in compliance with all applicable rules and regulations. The Company will respond remotely to customer connect and disconnect requests in a timelier manner thereby increasing customer satisfaction in the process. Additionally, the replacement of an aging meter population (characterized by an increasing meter failure rate) with a brand new meter population has the added benefit of reducing the Company's need to respond to meter replacements due to failures. As such, any reduction in physical visits should also result in a reduction in labor costs, vehicle and mileage costs, and other support equipment costs such as hand held devices.

Operating benefits may also accrue due to a reduction in the number of incoming calls to the customer call center. After an anticipated increase in call volumes during the initial deployment period due to customer questions about the new meters, there is an expected lower net steady state of call volumes. Most of the decrease is expected to be from reduced customer calls inquiring about a timely reconnection of service.

Additional benefits are also expected in the area of power quality, due to further development of the ability to monitor and analyze momentary outage and voltage issues. The ability to obtain information more frequently and across all smart meters will enhance our ability to analyze and proactively resolve distribution problems prior to customers notifying us about an issue. This will enable PPL Electric to better serve customers and utilize maintenance resources more effectively.

Outage management processes will be improved as PPL Electric introduces last gasp and power restoration message capability within the upgraded AMI solution. These capabilities will enable faster detection of outages and will speed power restoration processes. The upgraded AMI solution will also be able to provide near real-time outage status for individual meters. This will more accurately reflect the current state of restoration activity and allow resources to be utilized more effectively such that "OK on Arrival" occurrences (i.e. a power outage is restored on a separate, previous outage ticket) can be identified before a field crew is sent to a premise. As a result, the Company will be able to more effectively deploy and coordinate emergency restoration resources. This has the potential of translating into decreased time spent on storm restoration and reducing overtime and contractor expenditures.

AMI systems coupled with advanced analytic capabilities will allow for improved tracking of unaccounted-for energy, theft and tampering, by improving the ability to identify energy usage anomalies and correlating various events. The reduction of energy consumption on inactive accounts will also be realized by having the ability to remotely disconnect these premises. The end result is a more equitable system where more accurate responsibility of payment is borne by the parties responsible for the energy usage.

The new AMI solution will support enhanced customer self-service. The direct access capabilities of the new meters will enable HANs where customers can view and analyze near real time usage information. The upgraded customer portal will enhance customers' capabilities to analyze their energy history, review and compare promotions and rate plans, viewing and pay their bills online, and requesting start, stop, or transfer of service. Self-service may also improve operating efficiencies by decreasing customer call volume.

Another benefit from AMI systems coupled with advanced analytical capabilities is an improvement to distribution load management and other processes through the application of voltage and load monitoring. This monitoring will provide pertinent information for maintaining electrical system reliability, proactive correction of customer voltage issues, improved distribution load management, and improved accuracy of electrical equipment monitoring. The aggregated meter data can also provide valuable input to the electric system planning process.

Q. Are the benefits from the new SMP readily quantifiable?

A. Not at this time. The benefits of implementing the SMP are difficult to quantify. For example, when implementing the remote connect / disconnect functionality, the Company anticipates reduced service visits to customers' premises. However, the Company may not necessarily reduce its staff to account for this functionality, but instead may use these resources to perform other activities. The Company may also experience lower call volume, but it is not possible to predict with any accuracy a precise amount of savings.

Further complications exist in the Company's ability to quantify benefits because the Company currently operates an existing AMI system and has expanded its capabilities and integrated business processes to use advanced features such as remote connect / disconnect, voltage information, and outage detection through pinging. In doing so, benefits are currently being delivered, as reflected in better performance, improved customer satisfaction and reduced costs. In addition, many of the benefits will not be fully realized until the SMP is implemented. Therefore, due to the uncertainty and difficulty in quantifying operational savings associated with implementing the SMP, the Company proposes to reflect any savings associated with the SMP in future base rate cases as these savings are reflected in the Company's operations.

CUSTOMER REQUEST AND NEW CONSTRUCTION

Q. Please explain the Company's proposed plan for installing smart meters when requested by a customer or in new construction.

A. PPL Electric is proposing to continue to install its existing PLC meters for customer requests and new construction in each geographic region of its service territory until it has extended the RF Mesh network to that geographic location. Thereafter, PPL Electric will install RF Mesh meters for customer requests and new construction in the geographic location. If PPL Electric were to install RF Mesh meters in a geographic location before the appropriate communications systems are in place, it would have no way to read the RF Mesh meters in these areas. PPL Electric believes that this approach is reasonable for several reasons, including:

- PPL Electric already has an AMI solution that delivers many of the customer benefits required by Act 129 and the Commission's *Implementation Order*.
- The number of new construction customers that may be impacted is estimated at an average of 7,200 per year based on historical growth. In addition, the Company does not expect a significant number of existing customers to request a smart meter in advance of their scheduled deployment. The total number of potentially impacted customers over the life of the deployment (2014 – 2019) is estimated at 40,000.
- The Company is proposing to deploy an RF Mesh AMI solution and will be doing so based on geographic area, which will be the most efficient use of resources for deployment. New construction customers within geographic areas where RF Mesh network coverage exists will receive RF Mesh smart meters. Those customers that are outside of the geographic deployment area would receive an advanced PLC meter which would be changed during the normal deployment process, expected to be completed by 2019.
- PPL Electric already has a fully automated metering system and no longer has manual meter readers. As a result, the Company would still need to read those meters installed during the Post Grace Period. It would be expensive and resource intensive to develop micro RF networks to read these meters. Likewise, it would be costly and resource intensive to develop manual meter reading processes for a small number of customers.

SUMMARY

Q. Do you believe that the Company has developed a reasonable approach for implementing its SMP?

A. Yes. The expansive pilot programs and technology assessments alongside respected industry consultants have guided the decision making process for the SMP. The Company believes RF Mesh AMI technology represents the best option that exists in the marketplace today with respect to prudency, compliance with legal and regulatory requirements, and current and future business needs. The full solution, inclusive of the smart meter support systems, will allow the Company to ensure a high level of operational performance, maintain network and infrastructure integrity, and effectively manage the deployment of the new metering system.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation For Approval of Its Smart Meter Technology Procurement and Installation Plan

Docket Nos. P-2014-__________
and M-2009-2123945

Direct Testimony of Jason Kinslow

Date: June 30, 2014

Direct Testimony of Jason Kinslow

INTRODUCTION

Q. Please state your full name and business address.

A. My name is Jason Kinslow. My business address is 9201 Arboretum Pkwy, Richmond, VA.

Q. By whom are you employed and in what capacity?

A. I am an Associate Partner with IBM Corp. ("IBM") and my role on the PPL Electric Utilities Corporation ("PPL Electric") Smart Meter Plan project is that of the IBM Project Manager.

Q. What are your qualifications, work experience and educational background?

A. I have more than 18 years of experience in consulting in the electric utility industry. I have worked for IBM for approximately 4 years. In my current role I have worked with several US utilities in developing their smart meter strategies and plans. I graduated from Rennselaer Polytechnic Institute with a Bachelor of Science Degree in Industrial Management Engineering.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. No.

Q. What is the purpose of your testimony?

A. My testimony will provide background on IBM's services to PPL Electric in support of the technology assessments conducted in order to develop the Smart Meter Technology Procurement and Implementation Plan ("SMP").

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring parts of the SMP, PPL Electric Exhibit No. 1, Section III. Technology Assessment.

TECHNICAL ASSESSMENT

Q. What is IBM's experience with smart meters programs?

A. IBM has extensive experience as a leader among global consulting firms in the planning, implementation and operation of smart metering technology. IBM can point to smart metering engagements with 33 different utilities in 16 countries. Together, these projects encompass over 55 million smart electric meters, plus several million linked gas and water meters.

IBM has been involved in 5 of the 6 largest AMI projects conducted in North America, including work on projects at Southern California Edison, Pacific Gas & Electric, Ontario IESO, Oncor, Detroit Edison, and CenterPoint Energy.

Q. What role did IBM have in assisting with PPL Electric's Smart Meter Plan?

A. IBM was hired by PPL Electric in June 2013 to assist with several components of the AMI solution evaluation. This included facilitation of vision workshops, a technical assessment of AMI technologies, an organizational assessment, the creation of a financial analysis, and the development of an initial roadmap for implementation.

Q. What analysis was performed to evaluate potential smart meter systems?

A. IBM assisted the Company in conducting a series of interrelated assessments to evaluate potential smart meter systems. These assessments began in the fall of 2013 with the goal of deciding on a future smart meter technology for PPL Electric. The analysis was multi-faceted and covered vision, technical, market, regulatory and financial dimensions.

The process was initiated with a series of vision workshops to define the set of guiding principles by which to formulate the Smart Meter Plan. This provided high level guidance around strategic issues to facilitate the selection of a solution that would align with the Company's strategic direction.

The technical dimension covered the three primary smart meter technology types of Power Line Carrier, Point to Multipoint and Radio Frequency Mesh. The process progressed through a series of workshops which outlined and analyzed the inherent advantages and disadvantages of the different technologies. The technology types were compared and contrasted across seven feature areas – network design, bandwidth/latency, resilience/maintenance, security, maturity, outage management and smart grid synergies. The results highlighted strength and weakness areas for each technology type.

The market analysis was centered on the release of an RFI to nine AMI solution providers. As noted in Figure 5 of the Smart Meter Plan that was submitted June 30, 2014, the RFIs collected information on a diverse set of themes and requirements. The RFI responses were vetted with Subject Matter Expert (SME) teams and compiled among the technology types. The results provided the team with a snapshot of each technology type within the industry regarding scope, evolution, and capabilities. The RFIs also served to bolster and refine the learnings from the technical dimension and to provide a foundation for the regulatory and financial dimensions.

The regulatory dimension reviewed each technology type with the 15 smart meter capabilities set forth in Act 129 and the Implementation Order. *Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, Implementation Order, entered June 24, 2009. Each solution type was assessed against each of the 15 capabilities. The assessment was done on current market available functionality for each solution type.

The financial dimension looked at the installation and ongoing operational costs of each solution type. Vendor cost information was aggregated to create a financial view to support the Company's future smart meter solution. This financial view identified solution costs in key program areas, and is discussed in detail in the Smart Meter Plan that was submitted on June 30, 2014. The cost of each technology type was one of the factors considered in the overall solution evaluation.

Q. Based on the Company's analysis, what type of smart meter system is the Company proposing to implement?

A. As mentioned in Mr Glenwright's testimony, the Company's analysis resulted in the decision to replace the existing system with a Radio Frequency ("RF") Mesh solution. This solution is comprised of RF Mesh meters and field devices leveraging both public networks and PPL Electric's network for the Wide Area Network ("WAN") backhaul. The meters will be Zigbee enabled to support in-premise communications.

Q. What conclusions from the assessments support the proposal to implement an RF Mesh solution?

A. Several conclusions were drawn from the assessments, including: Act 129 Alignment, Solution and Systems Performance, and Technology Evolution.

As discussed in Mr. Glenwright's testimony, PPL Electric determined that upgrading the existing PLC AMI solution would not allow the Company to comply with all legal and regulatory requirements. An RF Mesh AMI solution type will allow the Company to meet these requirements.

An RF Mesh AMI solution provides strong operational performance and flexibility for future business and regulatory needs. The proposed solution will allow the Company to improve current processes around outage management and system analysis and forecasting. Additionally, with the upgrades in supporting systems the Company will be able to provide customers with faster and better usage information and self-service options.

Very few Investor Owned Utilities operate a similar PLC technological solution within the US, whereas RF-based solutions continue to exhibit industry dominance and expanded growth. An RF Mesh solution therefore provides PPL Electric with a substantial pool of peer companies with which to collaborate and benchmark. This includes the Company's peers in Pennsylvania, all of whom have elected to deploy an RF-based AMI solution to comply with Act 129 and Implementation Order requirements.

Q. Is the Company proposing to install additional systems to support smart meter technology?

A. Several systems will need to be implemented in support of the metering solution. The key systems of the solution are (1) a head end system for communication with all meters and field devices, (2) a meter data management ("MDM") system to receive, store, and process data from the head end, (3) a meter asset management ("MAM") system to register the solution assets and manage testing, maintenance and life cycle, (4) a network operating center ("NOC") system to manage the real time operations of the systems, and (5) a customer presentment portal to provide customers access to their validated usage information. In order to fully leverage the capabilities of these systems the Company plans to upgrade elements of its IT architecture and analytical foundation.

Q. How are these additional systems necessary to provide smart meter technology to customers?

A. The head end system collects the data (interval reads, outage and restoration messages, voltage data, etc.) from the meters and field devices and also sends out commands (connect/disconnect, firmware upgrades, etc.) to the same.

The meter data management system provides for storage of meter data from smart meters, including interval meter reads, and processes raw meter data with Validate, Edit and Estimate ("VEE") algorithms for utilization in corporate systems, such as billing and customer service.

The meter asset management system tracks the meter and field devices through their life cycle, capturing testing results, installation, maintenance, and retirement information. The system will also track software and firmware status and upgrades.

The network operating center system manages the operations of the meters and network equipment. It facilitates the identification of issues, troubleshooting and resolution. The system will enable the Company to actively manage the network and identify issues with the field devices and the meters before problems can escalate.

The customer presentment portal provides customers with access to view and analyzes their energy usage. It will also allow customers to perform self-audits of energy usage and initiate appointments.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation
For Approval of Its Smart Meter
Technology Procurement and Installation Plan

Docket Nos. P-2014-__________
and M-2009-2123945

Direct Testimony of Christine E. Ogozaly

Date: June 30, 2014

Direct Testimony of Christine E. Ogozaly

INTRODUCTION

Q. Please state your full name and business address.

A. My name is Christine E. Ogozaly. My business address is 827 Hausman Road, Allentown PA 18101.

Q. By whom are you employed and in what capacity?

A. I am Director of Advanced Metering and Data Operations for PPL Electric Utilities Corporation ("PPL Electric" or "Company")

Q. What are your qualifications, work experience and educational background?

A. I have 22 years of diversified experience at PPL Corporation. I began employment with PPL on June 1, 1992. I've held various staff engineering and leadership positions in PPL Electric. I also have several years' experience in real-time electricity trading working for PPL Energy Plus. In my current role as Director of Advanced Metering and Data Operations, I am responsible for the operation of PPL Electric's advanced metering system, meter test facility, metering support (engineering, standards and operating instructions), meter installation and maintenance for large customers, and the Company's revenue protection team. I have a Bachelor's degree from Wilkes University in Electrical Engineering.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of five components of PPL Electric's Smart Meter Technology Procurement and Installation Plan ("SMP"). I will describe PPL Electric's vendor selection process, SMP financial overview, evaluation of organizational impacts and program risks. Additionally, I will summarize details of the Company's communications strategy with regard to the Smart Meter Plan.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following sections of the Company's SMP (PPL Electric Exhibit No. 1): Section IV: Vendor Selection for Future Technologies, Section VII: Organizational Impacts, Section VIII: Program Risks, Section X: Financial Overview, and Section XI: Communications Strategy.

VENDOR SELECTION

Q. Please explain how the Company will select vendors to implement its proposed smart meter systems?

A. PPL Electric will follow a staged approach to vendor selection for implementation of its smart meter systems including the following steps: completing Requests for

Information ("RFIs"), detailed business requirements gathering, preparing and issuance of Requests for Proposals ("RFPs"), vendor selection, negotiations and contract execution.

In 2013, PPL Electric completed the RFI stage. The RFI process and results are described in detail in Section III: Technology Assessment. RFIs were issued for three components of the upgraded smart meter solution: AMI Solution (including meter hardware, head end technology and communications infrastructure), Meter Data Management System ("MDM"), and the Customer Portal technology. Evaluations of the responses were conducted and used as inputs into the solution decision process, which included the financial analysis. This stage also included identifying smart meter technology types and evaluating strengths and weaknesses.

Following submission of PPL's SMP, PPL Electric plans to solicit vendors for responses to a RFP for components of the smart meter solution. RFPs will be issued in two phases to capture the needed vendor support. The first phase of the issued RFPs will include: 1) AMI System (including meters and head end software); 2) MDM; 3) Customer Portal; 4) Network Operating Center ("NOC"); 5) Project Management Office ("PMO"); 6) System Integrator ("SI"); and 7) Meter Asset Management ("MAM"). The second phase will include RFPs for: 1) Deployment Vendor; and 2) Secondary Meter Vendor.

PPL Electric plans to issue RFPs to qualified vendors. The RFPs will ask vendors to comply with a series of requirements. These requirements will be divided into business, functional, and technical categories and will comprehensively describe the regulatory and business needs for the AMI solution. This requirements gathering phase is underway. PPL Electric began the process of requirements gathering for the AMI Solution, MDM, Customer Portal, and NOC RFPs in May of 2014. Subject matter experts from the Company's organization are participating in workshops and identifying system requirements.

In parallel, PPL Electric will work with its internal supply chain organization and external consultants to develop a vendor scoring mechanism for the RFPs. The Company will then select vendors using its established supplier selection methodology. This will include a detailed evaluation and scoring of the received RFP responses, evaluation of vendor pricing, requests for vendor follow-up as needed and oral presentations. The Company may request vendors to demonstrate performance of their communications or metering hardware and software in a lab environment to aid in the selection process. PPL Electric plans to notify the Commission of vendor selection upon completion of that effort.

Following vendor selection, PPL Electric will hold negotiations with the vendor to agree on the terms of the contract. This process will include discussion of and consensus on terms, pricing, service level agreements, support levels, schedule execution, warranty terms, key personnel, and other topics.

The Company seeks Commission approval of the vendor selection process described in Section IV. Vendor Selection for Future Technologies, but is not seeking Commission approval of the selected vendors.

Finally, responsible parties from both PPL Electric and the selected vendor's organization will execute the contract. PPL Electric will not execute contracts with vendors until final approval of its smart meter plan. Additionally, PPL Electric is requesting Commission approval of its SMP by December 31, 2014 to support final vendor selection and an early year 2015 start for implementation of critical information technology architecture and systems necessary for solution validation and testing in late year 2016, and full deployment of smart meters beginning in year 2017 through the end of year 2019.

FINANCIAL OVERVIEW

Q. What steps has the Company taken to estimate the costs of implementing the SMP?

A. PPL Electric used an iterative process to develop the inputs to the cost model for implementing the SMP. The data underlying the financial analysis was gathered through an assessment process involving RFIs from vendors, industry experience, subject matter experts from PPL, and consulting support from IBM.

Key activities performed in the development of the Financial Analysis included: 1) Defining the scope and components of the smart meter program; 2) Gathering relevant operational data and smart meter project projections; 3) Evaluating and validating data; 4) Identifying key smart meter project financial analysis modeling variables and assumptions; 5) Developing the analytical modeling structure; 6) Constructing a detailed view of the smart meter project financial analysis; 7) Reviewing the Business Case results with PPL Electric stakeholders and management.

It is important to note that PPL Electric's projection of costs for the various components of the SMP are high level estimates prepared through the previously described activities. These high level estimates are subject to change for a variety of reasons, including but not limited to, increases in vendor prices, changes in project scope, changes in the implementation timeline, unforeseen complications or changes in regulatory requirements. The cost estimates are not precise and will be revised over the life of the project. PPL Electric intends to recover its actual smart meter costs through the SMR whether they are more or less than the Company's initial estimates.

Q. Is the cost estimate dependent on the proposed implementation schedule?

A. Yes, PPL Electric's financial analysis included in Section X. Financial Overview is based on the proposed deployment schedule. This schedule anticipates all smart meter infrastructures will be built, all smart meters installed, and the system stabilized by the end of the year 2021.

Q. What are the projected costs for implementing the SMP?

A. PPL Electric's projected costs for implementing the SMP are contained in Section X. Financial Overview, Figure 15. For an 8-year cost schedule from 2014-2021, the total estimated cost of implementing this plan (2014-2021) is $449.3 million,

$407.9 million of which are for capital expenditures and $41.4 million for Operations and Maintenance (O&M).

Category	Capital (M)	O&M (M)	Total (M)
Meter	$284.9	$0.0	$284.9
Network & Network Management	$31.4	$7.9	$39.3
Information Technology	$53.0	$24.7	$77.7
Systems Integration	$8.8	$0.0	$8.8
Program Management	$23.2	$5.4	$28.6
Communications/Change Management	$6.6	$3.4	$10.0
Totals	$407.9	$41.4	$449.3

As shown in the above table, the costs incurred to implement this plan have been grouped into the following cost categories: 1) Meter; 2) Network & Network Management; 3) Information Technology; 4) Systems Integration; 5) Program Management; 6) Communications/Change Management. Within each of these categories, the costs were further broken down as either capital or O&M.

The total estimated capital meter cost, including installation, is $284.9 million. The most significant component of the meter cost is the $193.8 million equipment cost for the approximately 1.4 million meters. The weighted average meter cost is $130. A deployment vendor would be used to deploy meters at an average installation cost of $12.50 per meter and will total $20.0 million. Another component of the meter cost is related to repair of customer meter bases prior to full deployment totaling $67.2 million. Other items that are included in the total meter cost are associated with meter testing, meter failures outside warranty, and customer growth.

The costs for network installation and management are $39.3 million, including $31.4 million and $7.9 million, capital and O&M costs, respectively. The network equipment costs which include repeater and collector costs will be $9.9 million. The model assumes approximately 2,900 repeaters and 600 collectors will be needed. The total costs to deploy and install the network communications system will be $3.9 million and will include $2.6 million for project management, network planning and engineering, training, and testing and $1.3 million for equipment installation in the field. In addition to the costs associated with the installation of a network communications system, there will be additional costs to monitor and run a smart meter NOC totaling $6.7 million. Other components of the network and network management costs include backhaul, annual component failures, and annual maintenance.

The costs for information technology are $77.7M, including $53 million and $24.7 million, capital and O&M costs, respectively. Information Technology costs include software, hardware, vendor support and internal IT resources. The software costs of Head-End, MDM, Portal and MAM total $33.0 million while the associated hardware costs are $7.2 million. Resource costs including internal PPL IT resources and external vendor support are $37.4 million.

The total cost of system integration is estimated to be $8.8 million. The system integration category captures the costs associated with coordinating and managing the implementation of the different IT packages in an optimal manner. Associated tasks include providing overall architectural guidance and design, supporting security requirements, facilitating integration across the disparate systems and comprehensive test plan development and execution.

The costs of program management will be $28.6 million, including $23.2 million capital and $5.4 million O&M costs. The program management category captures the costs associated with overseeing the entire program through the end of 2021. The responsibilities associated with this category include program leadership, project management, requirements gathering, deployment planning, vendor management and business process development and redesign. The Project Management Office ("PMO") costs associated with external consultant support is also incorporated into this category.

The total cost of communications and change management will be $10 million, including $6.6 million capital and $3.4 million O&M costs. The estimated communications and change management costs cover two categories – training costs totaling $1.4 million and stakeholder communications costs totaling $8.6 million. Training costs include costs associated with both the development of training guides and modules as well as the delivery of training. The costs associated with communications incorporate costs for the development of smart meter plan related materials for all stakeholders as well as costs to deliver relevant education and messages through the appropriate channels in accordance with the timeframes outlined in Section XI: Communications Strategy.

Q. Please summarize the primary assumptions that were included in developing the cost estimate.

A. Primary assumptions included in development of the cost estimate are: 1) The timeframe is 8-years, starting with the beginning of the Post-Grace Period on July 1, 2014 and continuing through the end of the stabilization period in 2021; 2) A 3-year deployment schedule, with full deployment beginning in 2017; 3) Full Time Equivalent ("FTE") annual work hours are 2080 hours (52 forty-hour weeks); 4) Communications infrastructure will be installed prior to meter deployment in each specific geographic area; 5) Costs for meters, network communications, AMI head end, MDM and customer portal were based on RFI responses; 6) Costs for program management, change management and communications, IT support and system integration were based on PPL Electric and industry experience; 7) No costs for in-home customer devices such as displays, smart thermostats, have been included in the plan. The decision to purchase such devices from third party suppliers will be left to the customer; 8) The analysis assumes 100% deployment; customers will not have an option to opt out; 9) A deployment vendor will be used for deploying meters in the field; 10) Prior to deployment, meter base related repairs are assumed to be needed on 3% of the meter population at an estimated cost of $1500 per premise.

ORGANIZATIONAL IMPACTS

Q. Has the Company evaluated what impacts implementing the SMP will have on the Company as an organization?

A. Yes. The Company identified business units within PPL Electric's organization that will likely be affected by the transition to an upgraded AMI system utilizing RF mesh technology. For each unit, impacts were determined and categorized according to people, processes, technology, and organization. The result was an organizational impact analysis which documented expected changes and needs for the project and business during deployment and return to "normal" operations following the deployment.

Q. What are the major impacts to the Company of implementing the SMP?

A. The major impacts to PPL Electric in implementing the SMP are: 1) Providing necessary business resources for SMP implementation project; 2) Identifying processes that will be affected and need to be changed; 3) Aligning the organization and people to support the upgraded AMI technology and re-designed processes.

Q. How does the Company intend to address these impacts?

A. The Company plans to address these impacts by establishing a governance structure for the smart meter program implementation responsible to sponsor, drive and successfully execute the plan. Additionally, the Company has created a high level resource plan with estimates of resources needed to support the pre-deployment, deployment, and post-deployment activities. The Company collected data from the industry and peer utilities' programs to develop head count projections for specific job roles. The Company also plans to request that vendors provide detail around head counts required to operate their systems as part of the RFP process which will take place in the third and fourth quarter of year 2014.

Following the submission of this filing in 2014, PPL Electric will continue the organizational assessment and begin process re-design and planning for training required as part of a larger change management effort.

PROGRAM RISKS

Q. Has the Company evaluated the potential risks associated with implementing the SMP?

A. Yes. The Company recognizes that the smart meter plan will impact our customers and other key internal and external stakeholders. Accordingly, an upgraded AMI solution requires a comprehensive risk assessment and management process.

Q. What are the primary risks that the Company has identified?

A. The Company has identified the following primary risks associated with implementing the smart meter plan: 1) Unanticipated regulatory and legislative requirements that may significantly alter the schedule, scope, or budget of PPL Electric's Smart Meter Plan; 2) The availability of skilled resources needed for the Company to successfully complete the work required prior to and during the new smart meter deployment. Also, new skillsets will be required to support the AMI communications change from PLC to RF mesh; 3) PPL customers have already experienced benefits from the existing advanced metering system. Customers will need education on the benefits of the upgraded metering system, and the change to an RF mesh technology. Education and communications about deployment are key areas to positively impact customer satisfaction; 4) Vendors chosen to support the AMI solution must perform in a manner that meets the Company's expectations and the SMP schedule. There is additional risk around integration of disparate vendor software systems; 5) The technology may become obsolete during the 10 year program course; 6) The upgraded AMI solution requires a large-scale and complex IT project including installation of new vendor-purchased systems, integration with existing corporate systems, and data conversion to enable communications across systems; 7) The Company is replacing a mature AMI system with MDMS. PPL Electric is unique among its peers by being one of the first utilities to encounter this challenge. As a result, the Company expects limited benchmarking and industry experience with this effort. There will be IT complexity due to the simultaneous operation of both the PLC and RF Mesh solutions as the Company transitions from the former to the latter. This transition brings unique challenges to the Company, including the migration of customer data from existing systems to new ones, the development of processes for operating multiple AMI solutions simultaneously, and maintaining high meter read rates throughout the deployment time period.

Q. What steps is the Company taking to mitigate risks?

A. The Company is taking the following steps to mitigate risk associated with SMP implementation: 1) PPL Electric has created an ongoing risk management process to track and manage the program risks identified above and others as they are identified. This process includes identifying risks and evaluating possible impacts, in addition to creating mitigation plans to manage them. Furthermore, the Company is leveraging the extensive experience it gained during the installation of its first AMI solution in 2002, and from successfully operating that system to this day; 2) The Company will continue to engage with vendors of smart meter technology and peer utilities that have used those vendors for their own deployments. This engagement will take the form of attending industry conferences, in-person site visits, and conference calls and other meetings to gain insights and learn best practices for specific solution types. Since PPL Electric is proposing an RF Mesh solution, it will focus on site visits with utilities that have successfully deployed and operated this type of AMI technology; 3) PPL Electric will continue to engage industry expertise and external program support. Beginning as early as 2009, PPL Electric retained external consultants from Black & Veatch experienced with smart meter deployments to assist in evaluations of the current state AMI solution. The Company continued this practice in 2013-2014 with the engagement of IBM. PPL Electric will continue the practice of soliciting vendors who have high levels of experience with the chosen AMI solution, including technology vendors for solution hardware: meters, head end technology, NOC, and MDM. Vendor contracts will be written considering lessons learned from AMI programs at peer utilities. Hardware vendors will also be required to submit to industry-approved testing processes, to ensure compliance with nationally-recognized credentials and measures for security, safety, and operation. PPL Electric will also conduct its own vigorous testing in both lab and field environments. Lab and field testing will include detailed end-to-end testing of meters and communications. External support will allow the Company to mitigate a variety of risks, including resource availability through the use of external staff augmentation for project staff and potential operation of the legacy AMI system. Contracted services will also be used to mitigate risk during the meter deployment through the use of a Company-chosen meter deployment vendor to conduct physical meter installations at customers' premises. Vendor support may also be leveraged for IT integration efforts; 4) PPL Electric's choice of an RF technology type allows for technical flexibility versus other technology types. RF technology has seen high adoption rates for AMI solutions in recent years. It is noted that PPL Electric's peers in Pennsylvania have all chosen to deploy RF-based AMI solutions to comply with Act 129 requirements. Based on the Company's assessment completed in 2013, an RF solution type also allows for integration with distribution automation and advanced analytics capabilities. New requests from regulatory or legislative bodies will be easier to respond to with a system that is more flexible and scalable and the risk of technology obsolescence is mitigated through the use of a widely-adopted technology type; 5) PPL Electric has developed an implementation strategy that provides for strategic timing of the AMI solution and deployment. As described in the SMP Roadmap contained in Section V: Implementation Plan, Figure 8, the Company plans to complete the required IT and business process review to implement an IT system architecture change and install a new AMI head-end, MDMS, MAM, NOC and customer portal prior to full meter deployment in 2017. This is a significant IT and business effort that will require external vendor support. The intent of adopting this aggressive IT build is to minimize potential re-work involved with integrating RF mesh communication systems and meters to the Company's existing AMI systems. This plan improves program efficiency, but makes IT system implementation a critical path item in the schedule requiring adequate support from the PMO and external system integrator; 6) PPL Electric will use a staged deployment approach to manage the impact of the new AMI solution. As described in Section V: Implementation Plan, deployment will begin in the second half of 2016 with a Solution Validation period. This phase is designed to ensure that the system is functional end-to-end prior to beginning full deployment. Beginning with full deployment in 2017, smart meter functionality will be staged through 2019 to accommodate IT build timeframes and to allow for proving out of functionality to support Act 129 and *Implementation Order* requirements; 7) PPL Electric will identify advanced functionality that could be supported by the upgraded AMI solution, and carefully plan for and stage that functionality. This approach will be used for new functionality enabled by the AMI solution that is not already operationalized within PPL Electric's business. This will include redesigning business processes to fully utilize meter data, such as voltage, temperature, power restoration messages, and other message alerts. Additionally, expanded or new functionality such as remote disconnect and Home Area Network ("HAN") devices will be staged throughout the deployment period. Some of the later-stage applications of the new AMI solution, include integration with distribution automation, the use of advanced analytics, and other areas as identified by future business requirements; 8) PPL Electric will exercise due diligence in system requirement design and vendor planning. The Company has already begun the process of developing detailed business requirements for vendor RFPs which will be issued later this year. These requirements will contain business and functional areas required for compliance by vendors involved in the RFP process. PPL Electric will include compliance with these requirements as part of the scoring of vendors during the RFP evaluation process and prior to selecting a vendor for the major components of the upgraded AMI solution. Detailed requirements, along with clear roles and responsibilities, establishing service level agreements, and having a disciplined program management approach will help to mitigate risks related to vendor performance and integration; 9) PPL Electric recognizes the need for customer engagement and education with the upgrade to an RF Mesh solution. This technology is new to Company personnel and its customers. As such, the Company will prepare educational materials to ensure that customers are educated on the benefits and uses of the technology. This education will include details regarding the protection of customer data, and the security measures put in place by the Company to protect both customer and business data in its IT systems and communications networks.

COMMUNICATIONS STRATEGY

Q. Please summarize the Company's communication plan with respect to the SMP.

A. PPL Electric's communications related to the Smart Meter Plan will ensure that customers are informed about AMI benefits and the installation experience, including when they can expect new meters. The Company also intends to provide sources of information about AMI, and contact information for scheduling installation appointments. These activities will also include addressing any concerns about the program.

Q. What are the key messages that the Company intends to communicate?

A. PPL Electric Utilities intends to communicate the following key messages: 1) We propose to upgrade our existing advanced meters to provide additional capabilities, improve service to customers and comply fully with Act 129; 2) The new system will comply with Act 129 and *Implementation Order* requirements, including enabling customers to receive real-time pricing information; support home area networks, provide additional real-time information to customers regarding energy usage and cost; and support operational improvements, including remote connect / disconnect and outage detection and restoration; 3) After thorough study, we have determined that we will propose an RF solution, as opposed to our current Power Line Carrier system; 4) Based on current analysis, we expect the project cost will range between $425 and $450 million; 5) We expect to deploy the meters between 2017 and 2019.

Q. What audiences will the Company seek to educate regarding its SMP?

A. PPL Electric plans to communicate with the following audiences regarding its SMP: PPL Electric customers, Smart Meter Stakeholder Group, elected officials, other PPL Electric employees in Pennsylvania, the media, public or community groups, such as chambers of commerce, consumer organizations, low income advocacy groups, the financial/investment community, IBEW 1600 leaders/contractors, PPL Electric retirees and suppliers.

Q. How will the Company develop communication materials?

A. The Company will develop communication materials using internal PPL Electric personnel with vendor support. The initial communication materials will focus on customer and employee education about the program. Call center representatives will receive training and talking points of the SMP. The Company will establish a dedicated internet website which will contain program information, Frequently Asked Questions ("FAQs"), and contact information. PPL Electric representatives will also meet with community and public leaders about the program. Customer communication may be in the form of direct mail, e-mail messaging or bill inserts. PPL Electric will conduct necessary consumer research to understand/refine messages and to ensure messages and supporting information are appropriately targeted.

Q. When will the Company communicate deployment messages to customers?

A. PPL Electric will create communications materials related to the deployment of upgraded smart meters from years 2017 to 2019. These communications will focus on notifications to customers of the deployment schedule, including proactive notifications prior to premise visits to install the upgraded meters.

PPL Electric will follow a staged process to communicate deployment activities to customers:

Ninety (90) days prior to installation, PPL will notify customers that deployment is being planned in their region or geographic area. This communication will include education about the upgraded smart metering system and website information to access additional detail via the dedicated microsite. Also during this phase, PPL Electric will, as appropriate, hold meetings with public leaders, and conduct other outreach sessions to proactively educate customers prior to installation.

Sixty (60) days prior to installation, PPL Electric will continue customer education and outreach efforts. These efforts will also include additional FAQs developed in tandem with the deployment vendor to address any customer concerns.

Thirty (30) days prior to installation, PPL Electric will send direct mail and E-mail notifications to customers reminding them of the upcoming premise visit to install an upgraded smart meter. The Company will provide an estimated timeframe for the day(s) during which the installation will take place.

Q. Does this conclude your direct testimony at this time?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation
For Approval of Its Smart Meter
Technology Procurement and Installation Plan

Docket Nos. P-2014-__________
and M-2009-2123945

Direct Testimony of Kent Simendinger

Date: June 30, 2014

Direct Testimony of Kent Simendinger

INTRODUCTION

Q. Please state your full name and business address.

A. Kent Simendinger, PPL Electric Utilities Corporation ("PPL Electric" or the "Company"), Two North Ninth Street, GENN1B, Allentown, PA 18101.

Q. By whom are you employed and in what capacity?

A. My current role is as Senior Manager of the Information Assurance Group – IAG at PPL Services. Functioning within IT as a workgroup (PPL Electric refers to its IT department as "Information Services Department", or "ISD" for short), I lead a group of 20 individuals in carrying out the primary responsibilities for PPL Electric's overall cyber security program, including security policies, access and identity management, internal/external security technology and process protections, security incident response, Business Continuity and Disaster Recovery, security awareness and education, and leadership for ISD's various compliance control commitments, such as for Security Exchange Commission (SEC) Sarbanes-Oxley (SOX) financial controls, or NERC Critical Infrastructure Protections (CIP) as mandated by the Federal Energy Regulatory Commission (FERC)..

Q. What are your qualifications, work experience and educational background?

A. I have nearly 30 years of IT experience across disparate industry and technical spectrums. My undergraduate (BA, New College of Florida) and graduate work

(Pennsylvania State University) focused on psychology, and my career from the outset has translated that human perspective to the technical realm, beginning with the early days of personal computers and midrange systems to today's distributed, internet connected environment. At PPL Electric for nearly 14 years, half of those in IAG leadership roles, I also have had leadership roles for overall endpoint (hardware and software) architectures, and corporate application development/integration best practices. Each of those roles has had significant aspects concerned with cyber security and compliance support, following along with the emerging dominance of the role of the Internet, and its companion risks of malicious software, cyber vulnerabilities, and attacks from threat actors of all types. Throughout my tenure in IAG, I have also served as ISD's Designated Compliance Manager for NERC CIP compliance, ensuring that ISD fulfills its responsibilities as part of the overall corporate program to protect PPL Electric's critical cyber assets that provide reliability to the bulk electric system. This extensive involvement covered two successful, separate on site mandated audits by NERC's designated regional entity ReliabilityFirst (2011 and 2012) for PPL Supply and PPL Electric Utilities, annual self-certifications of compliance, and provides a solid security foundation as part of our overall "defense in depth" strategy.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. No, I have not.

Q. What is the purpose of your testimony?

A. I am here to outline PPL Electric's cyber security approach and roadmap as it relates to protecting the systems (hardware, software, and communications) to be designed and implemented, as well as its associated data privacy needs as part of PPL Electric's submitted "Smart Meter Technology Procurement and Installation Plan."

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Chapter VI, "Cybersecurity and Data Privacy" of PPL Electric Utilities Corporation's Smart Meter Technology Procurement and Installation Plan (PPL Electric Exhibit No. 1).

CYBERSECURITY AND DATA PRIVACY

Q. How does the Company currently maintain the security of its IT systems?

A. At a high level, PPL Electric currently maintains and continues to enhance cyber security through a "Defense in Depth" approach. This strategy defends systems against attacks using multiple, independent methods, layering defense mechanisms to form a comprehensive shield. Such layers (ranging from security policies, security awareness for employees/contractors, physical security protections, firewalls to block unnecessary traffic, logging of activity, 24x7 monitoring of activities, anti-virus and anti-spam tools, encryption of sensitive data, strong passwords, and many more) prevent and slow the advance of attackers who may try a variety of malicious techniques to breach data or systems such as Smart Meters and associated supporting infrastructure, and affords opportunity for successful incident response by PPL Electric's cyber security team. Given that there is no singular technology or process to safeguard systems and data in today's complex and challenging environment, a defense in depth approach is a proven method to mitigating the risks inherent in such environments, and is paramount as the technical landscape evolves.

Q. What steps will the Company take to ensure that cyber security risks are adequately addressed with the implementation of the SMP?

A. First, PPL Electric maintains a strong internal cyber security focused IAG workgroup, which includes trained, certified and experienced personnel to deliver on cyber security and privacy requirements. As part of a cross-functional project team, PPL Electric's IAG employees work with business and IT partners to implement and monitor the layers of cyber defenses. The Company ensures that these individuals are kept up to date with the latest information on cyber security and privacy best practices and are knowledgeable with respect to emerging threats to the metering infrastructure. IAG members hold government Secret clearances, and participate in local, regional and national information and intelligence sharing. This enables the team to keep up with emerging threats, defenses design, and evolving technologies, including Smart Meter technology. PPL Electric also engages experienced and objective third party assessors to: (1) perform skills, design, and operational reviews, and (2) benchmark against peers and accepted industry cyber security standards and frameworks. In addition, PPL Electric will leverage (and develop if need be) the appropriate internal policies, standards methodologies, and procedures necessary to secure SMP assets and data.

As informed by security and privacy best practices from industry or government-based sources, PPL Electric Utilities will look to such guidance for the effective means to protect the Company's assets and customer data from a variety of threats, whether known or potential.

Finally, PPL Electric is committed to investing in the appropriate and effective cyber security technology to support an overall defense in depth, and specifically the cyber assets, infrastructure, and data that form the SMP ecosystem.

Q. How will the Company assess security issues with AMI System equipment?

A. To ensure cyber security risks are adequately addressed, PPL Electric will utilize its project management methodology to aid in creating cyber security and data privacy controls, processes and procedures. The project management methodology process is a risk management-based approach for identifying, quantifying, and mitigating risks throughout a project's lifecycle. This approach enables PPL Electric to understand and manage the threats and risks in its current operations, as well as to identify potential future risks and develop appropriate mitigation plans. AMI System equipment provided by third party vendors will be evaluated throughout the overall development lifecycle for compliance with Cyber Security Requirements derived from, among other standards and security framework sources, PPL Electric's own Information Security Standards and the National Institute of Standards and Technology (NIST) standards specific to smart grid components.

In addition to the overall project management methodology process, the Smart Meter Project will create a Risks Register document, and any cyber security related risks will be entered and managed accordingly. Part of that effort is a Security Risk Assessment (SRA) - a review that provides a baseline for the development of risk mitigation actions needed to protect the utility's systems and environments. It is conducted using a well-defined set of information security standards, guidelines, and industry best-practices. Vulnerability scans and penetration testing (where trusted and skilled partners (Certified Ethical Hackers) attempt to circumvent the protections in place) will also be conducted on the operational system, prior to deployment and post-deployment, to ensure the system adheres to the cyber security design.

Q. Please explain the Company's approach to system security testing.

A. Vulnerability scans provide a quality assurance check using automated tools and manual scanning to verify configuration items including, but not exclusive to: firewall rules, port configurations, password structure and complexity, user authentication and access permissions. Penetration testing is the best indicator of real-world vulnerability to cyber-attacks, both internal and external. Conducted by the objective, experienced and knowledgeable Certified Ethical Hackers noted earlier, this activity determines the degree to which the systems are vulnerable to a variety of cyber-attacks. The team will conduct a series of targeted attacks from the smart meters to the AMI systems and document the gaps and vulnerabilities discovered. These gaps and vulnerabilities will be managed and/or mitigated by the project team.

Q. What steps will the Company take to maintain the privacy of customer data?

A. The first step is to determine the type of data to be protected, and the appropriate security controls thus necessary to protect it. For the Smart Meter Project, IAG will also follow NIST's "Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and the Smart Grid and conduct a privacy impact assessment (PIA) before any deployment. The PIA will help the project team with the following: 1) Identifying and managing privacy risks: Exercises to identify potential privacy risks early in the project and demonstrate strong governance and business practices. 2) Avoid unnecessary costs: Consider any safeguards as part of the project budget and thereby avoids unexpected costs after deployment. 3) Meeting legal requirements: Implementing the appropriate controls adhere to legal requirements. This also applies when engaging a third party, where the data owner is responsible for ensuring the appropriate controls are in place to protect personal data.

Q. What security standards will the Company follow with respect to the Smart Meter Project?

A. Standards/guidelines will include, but are not exclusive to, NIST SP 800-53 "*Recommended Security Controls for Federal Information Systems and Organizations*"; NIST SP 800-30 "*Risk Management Guide for Information Technology Systems*"; NIST SP 800-60 "*Guide for Mapping Types of Information and Information Systems to Security Categories*"; Federal Information Processing Standards (FIPS) 199 "*Standards for Security Categorization of Federal Information and Information Systems*"; NISTIR 7628 "*Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and Smart Grid*"; NIST SP 800-115 "*Technical Guide to Information Security Testing and Assessment*"; DHS/ Energy Sector Control Systems Working Group's (ESCSWG) "*Cybersecurity Procurement Language for Energy Delivery Systems*"; NERC Critical Infrastructure Protection (CIP) current v3 and planned V5 standards as appropriate; other security frameworks such as International Organization for Standardization (ISO) 27001 for Information security management, the SANS Institute's (SysAdmin, Audit, Networking, and Security) "Critical Security Controls for Effective Cyber Defense", NIST 2014 voluntary cyber security framework, Department of Energy's Cybersecurity Capability Maturity Model (ES-C2M2); as well as PPL Electric Utilities own internal information security standards.

Q. Please summarize the Company's overall security objectives.

A. PPL Electric's security and data privacy objectives are to implement and maintain effective preventative and detective controls commensurate to the cyber risks that threaten the confidentiality, availability, and integrity of our assets, including smart meter technologies.. PPL Electric's defense in depth strategy will address the proposed Smart Meter systems and sensitive data, protecting these assets from potential compromise and misuse that could threaten electric reliability or data privacy.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

PPL Electric Statement No. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

**Petition of PPL Electric Utilities Corporation
For Approval of Its Smart Meter
Technology Procurement and Installation Plan**

**Docket Nos. P-2014-__________
and M-2009-2123945**

Direct Testimony of Bethany L. Johnson

Date: June 30, 2014

Direct Testimony of Bethany L. Johnson

INTRODUCTION

Q. Please state your full name and business address.

A. My name is Bethany L. Johnson. My business address is 2 North Ninth Street, Allentown, Pennsylvania, 18101.

Q. By whom are you employed and in what capacity?

A. I am employed as the Manager of Regulatory Compliance by PPL Electric Utilities Corporation ("PPL Electric" or the "Company").

Q. What are your duties as Manager-Regulatory Compliance?

A. I am responsible for PPL Electric's compliance with the regulatory requirements of the Pennsylvania Public Utility Commission ("PUC" or the "Commission"). As part of this function, I am responsible for the preparation and review, and technical oversight and guidance, of the development, content, and structure of cost allocation and revenue requirement studies. In addition, I am responsible for all aspects of PPL Electric's distribution rates and tariffs. I also prepare and present expert testimony regarding these and other ratemaking-related issues.

Q. What is your educational background?

A. I graduated from King's College in 1999 with a Bachelor of Science Degree in Finance, and from Moravian College in 2003 with a Master of Business Administration.

Q. Please describe your professional experience?

A. In 2000, I was employed by PPL Global Operations, where I supported the accounting and financial reporting activities of the company's domestic activities. In 2001, as a result of realignment, I joined PPL Generation. In this position, my responsibilities include cost control, budgeting, reporting, and management of the forecasting process for large construction projects, as well as the administration of construction and financing contracts. In 2004, I rejoined PPL Global as a Senior Business Analyst with responsibility for maintaining, analyzing, consolidating, and presenting the business plans and operational performance results of the Company's international affiliates. In 2007, I joined PPL Energy Services Group as a Business Analyst providing financial modeling and analytical support for the evaluations of acquisition, development, and divestiture opportunities. In 2009, I joined PPL Electric as a Project Controls Specialist providing advanced cost analysis for distribution and transmission projects. Later in 2009, I assumed the position of Financial Business Planning Specialist in the Regulatory Compliance Department. In August, 2012, I was named to my current position as Manager – Regulatory Compliance for PPL Electric.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. Yes, I testified before this Commission in PPL Electric's most recent base rate case at Docket No. R-2012-2290597. In addition, I have testified in several Section 1307(e) reconciliation hearings. I have testified relative to PPL Electric's

Generation Service Charge Rider at Docket No. C-2013-2367475, the calculation and implementation for the Company's Distribution System Improvement Charge at Docket No. P-2013-2325034, the Company's Transmission Service Charge Refund Plan at Docket Nos. M-2010-2213754 and M-2011-2239806, the Company's Default Service Plan III at Docket No. P-2014-2417907, and the Company's Act 129 Phase 1 and Phase 2 riders at Docket Nos. C-2013-2398442 and C-2013-2398440.

Q. What is the purpose of your testimony?

A. My testimony and accompanying exhibits describe and support PPL Electric's proposed modifications to its existing Section 1307(e) cost recovery mechanism that will be used to recover the costs of its proposed Smart Meter program for the period January 1, 2015 through December 31, 2025 and its impact on customer rates.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Section 12 of the Company's Smart Meter Technology Procurement and Installation Plan ("SMP") which is identified as PPL Electric Exhibit 1 and the *pro forma* tariff pages that are provided as Exhibit BLJ-1 to my Direct Testimony.

COST RECOVERY

Q. How does the Company currently recover its smart meter costs?

A. The Company currently recovers costs related to its Smart Meter pilot programs through its SMR in accordance with the Commission's Order entered on June 24, 2010 at Docket No. M-2009-212945. The Company implemented its SMR on January 1, 2011 and has filed informational filings and annual 1307(e) reconciliations. In accordance with its tariff, PPL Electric files its SMR with the Commission by August 1 of each year.

Q. Is the Company proposing to continue to recover costs for the current SMP through the SMR?

A. Yes, the Company proposes to continue recovering costs of its approved SMP pilot programs and any over or under collection through the existing SMR mechanism.

Q. Explain the calculation of the Company's current SMR.

A. Currently, the Company recovers the annual budgeted amount of all costs required for the Company to implement its approved Smart Meter Plan during a compliance year. The SMR is applied on a non-bypassable basis to charges for electricity supplied to customers who receive distribution service from the Company and is computed separately for each of the Residential, Small C&I, and Large C&I customer classes. It is applied to Residential and Small C&I customers on a $/kWh basis and to Large C&I customers on a $/bill basis. The annual budgeted amount is the sum of all direct and indirect capital (e.g. return of and return on applicable smart meter-related investment) and operating costs (e.g., applicable O&M and taxes), including all deferred design and implementation and development costs and general administrative costs required to implement the Company's SMP in the compliance period.

The capital and operating costs of each SMP pilot program available to only one customer class is directly assigned to that customer class. The costs of SMP pilot programs which cannot be directly assigned to one customer class are allocated to the three customer classes on the ratio of number of meters assigned to the class, divided by the number of meters for the entire system.

The Company also includes in its rate calculation the net over or under collection of the SMR charges as of the end of the 12-month period ending June 30 of each year. Reconciliation is conducted separately for each of the customer classes and interest is computed monthly at the legal rate of interest of 6% from the month the over or undercollection occurs to the effective month that the overcollection is refunded or the undercollection is recouped.

Q. Does the Company propose to recover the costs of its proposed SMP through the SMR?

A. Yes. PPL Electric is proposing to continue recovering its SMP related costs through the SMR with several modifications that are discussed below and further set forth in Exhibit BLJ-1. The proposed SMR will be updated to include any capital and expenses not previously accounted for in base rates or the SMR. The Company has used estimates in its business case and customer impact estimates; however the rate itself will be based on actual historic costs recorded on the books and records of the Company for the applicable time period. Actual costs may be higher or lower than estimated costs.

Q. Is the Company proposing any changes to the SMR?

A. Yes. The Company is proposing several changes to its SMR. First, the Company is proposing to calculate the rate based on historic data instead of budgeted data as is done in the current SMR. PPL Electric currently bases its rates on the annual budgeted amount for the year in which the rates take effect, the Company is proposing to change the costs included in the rate calculation to include expenses and plant placed in-service on the books and records during the applicable period, rather than estimates. This should reduce the potential over or under collection and its impact on future rates.

Second, the Company is proposing to change the proposed SMR on a quarterly basis versus annual changes. This will provide smaller, more frequent price changes for customers instead of a larger, annual price change.

Third, the Company is proposing to change the pricing for residential and Small C&I customers to a customer charge ($/customer) from a usage based charge

($/kWh) in the current rider, which is consistent for how meters are handled in the Company's base distribution rates. This will maintain a consistent methodology should the Company include the Smart Meter costs into base rates in the future.

Q. How will PPL Electric determine what costs are recovered in the SMR?

A. PPL Electric has identified the specific accounts and projects that will be used to track the SMP approved capital and expense costs during the implementation. PPL Electric has developed a process to track this specific property throughout its lifecycle. The proposed SMR will reflect only eligible plant additions placed in-service during the appropriate time period and operating expenses as recorded on the Company's books and record.

Q. Is the Company proposing to recover its SMP development costs?

A. Yes, the Company is proposing to recover the costs that it is incurring to develop the plan through December 31, 2014. These costs include design, implementation, and development costs, including but not limited to technology assessment and selection, and general administrative costs such as program management costs, required to prepare the Company's Smart Meter Plan Petition. The Company is requesting deferral and recovery of these costs over three application years.

Q. Describe how the Company will calculate its proposed Smart Meter Rider.

A. All smart meter costs associated with the implementation of the new meters will be captured in the SMR. The Company proposes to calculate the SMR using the same formula it currently uses (with the modifications discussed herein and in Exhibit BLJ-1) to provide a clear understanding of the methodology used to determine the rates for a given period. First, the Company will calculate the revenue requirement for any given filing period which includes a return on and return of actual net plant-in-service, depreciation expense, and operating expenses (e.g., applicable O&M and taxes). In the return calculation, PPL Electric will use its actual capital structure and cost of long-term debt and preferred stock as of the last day of the most recent quarter for the prior three-month period with a one-month lag and the return on equity approved in the Company's last base rate case that is less than three years old. If, however, the last base rate case is more than three years old, the quarterly rate of return on equity as calculated and recommended by the Bureau of Technical Utility Services for the Distribution System Improvement Charge will be utilized. The total revenue requirement is allocated to the rate groups based on the meter investment associated with each customer group, consistent with the Company's approved Cost of Service allocation methodology. Then, a reconciliation adjustment is made on an annual basis to reconcile for any over/under collections by customer class. The customer charge is calculated by taking the net revenue requirement divided by the number of bills in each customer class projected for the rate application period. Finally, the customer charge is grossed-up to recover Pennsylvania gross receipts tax.

Q. Does the Company currently include ADIT in its SMR revenue requirement and does it propose to continue to do so?

A. Yes, the Company currently includes ADIT in its SMR revenue requirement and anticipates continuing its existing calculation. However, the Company will not make a rate base adjustment for ADIT assets related to a tax net operating loss carryforward.

Q. How does the Company propose to calculate and incorporate over/under collections into the SMR?

A. The revenue received under the proposed SMR will be compared to the costs for the 12-month period ending December 31 of each year. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year. Interest shall be applied to both over and under collections at the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection law (41 P.S. §§101, *et. seq.*) and will be refunded or recouped in the same manner as an over or under collection.

Q. Will the Company have an unrecovered investment in its existing meter assets when the new system is installed?

A. Yes. PPL Electric's current meters are not fully depreciated and will not be fully depreciated by the end of the new meter deployment period. The SMR as proposed does not include an adjustment for recovery of the remaining investment in the Company's existing meter assets. PPL Electric proposes to continue recovering depreciation expense on its existing meter assets through distribution base rates using the current meter life. When the Company submits its next base rate case, it will propose to accelerate the period over which it will recover the remaining investment in its existing meters (i.e., the balance as of December 31 of the year before new distribution base rates would take effect) over a period that coincides with the completion of the new meter deployment period through its territory.

Q. Will the Commission have an opportunity to review the proposed SMR on a periodic basis?

A. Yes. The Commission will have a number of opportunities to review the proposed SMR. First, and most fundamentally, the Commission will have an opportunity to review each of the Company's quarterly computation and annual reconciliation filings of the proposed SMR. Moreover, as specifically stated in the Company's tariff, "application of the SMR shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the SMR and the costs included therein."

Q. What customers will be charged under the proposed SMR?

A. PPL Electric's proposed SMR will be applied to each customer class based on costs assigned or allocated to that class, as described in the calculation above, and consistent with the Company's approved Cost of Service methodology.

Q. What is the impact of the proposed SMR on customer rates?

A. Based on the SMP as proposed and the currently estimated costs, PPL Electric projects the proposed SMR will increase an average residential (1,000 kWh) customer's total monthly electric bill by approximately $2.79 over the life of the meter. After peaking in 2019, the charge may decline each year due to some of the assets reaching the end of their depreciable life. I note that PPL Electric's estimate of costs is subject to change, and PPL Electric is proposing to recover its actual SMP costs. If SMP costs are more or less than the Company's estimate, this will impact the estimated customer costs as well.

Q. Will the SMR appear as a separate charge on customers' bills?

A. The proposed SMR will appear on the bill in a similar manner as the current SMR. For the Residential customer class, the current SMR ($/kWh) charge is included in the $/kWh distribution charges of the bill. The Company will include the proposed SMR charge ($/customer) in the customer charge portion of the bill for the Residential customer class.

For the Small C&I and Large C&I customer classes, the current SMR ($/kWh for Small C&I, $/bill for Large C&I) is a separate line item on the customer's bill. The

Company will continue to reflect the proposed SMR charge ($/customer) as a separate line item for the Small C&I and Large C&I customer classes.

Q. When will the proposed SMR go into effect?

A. PPL Electric requests permission to implement its proposed SMR on January 1, 2015. The Company is making this request to effectuate the changes to its Smart Meter rider in accordance with its Smart Meter Plan filing.

Q. Will customers pay both the current and proposed SMR at the same time?

A. Yes, customers would pay for both the current and proposed SMR for a limited time. Because the Company does not anticipate any additional expenses related to the Pilot programs, only the remaining return of and return on Smart Meter pilot program rate base and over or under collections would continue through the existing SMR.

Q. How often will PPL Electric adjust the proposed SMR?

A. The Company is requesting permission to adjust the proposed SMR rate on a quarterly basis to reflect SMP approved plant additions placed in service during the three-month period ending one month prior to the effective date of any SMR update. In the *pro forma* tariff attached as Exhibit BLJ-1, PPL Electric has provided a chart of the effective dates of its proposed SMR updates, and the corresponding period for plant additions and expenses that will be reflected in each update. Ten days prior to each quarterly update, PPL Electric will file supporting data for the update with the Commission and serve the data upon the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

Exhibit BLJ-1

SMART METER RIDER – PHASE 1

A Phase 1 Smart Meter Rider (SMR 1) shall be applied, on a non-bypassable basis, to charges for electricity supplied to customers who receive distribution service from the Company under this Tariff.

The SMR 1 shall be computed separately for each of the following three customer classes:

(1) Residential: Consisting of Rate Schedules RS and RTS (R),
(2) Small Commercial and Industrial (Small C&I): Consisting Rate Schedules GS-1, GS-3, IS-1 (R), BL, SA, SM (R), SHS, SE, TS (R), SI-1 (R), and GH-2 (R) , and
(3) Large Commercial and Industrial (Large C&I): Consisting of Rate Schedules LP-4, LP-5, LPEP, and L5S.

The SMR 1, as computed using the formulae described below, shall be included in the distribution charges of the monthly bill for each customer receiving distribution service from the Company and shall be reconciled on an annual basis for undercollections and overcollections experienced during the previous year. Charges set forth in the applicable rate schedules in this tariff have been adjusted to reflect application of the currently effective SMR 1.

The SMR 1 for the Residential class and the Small C&I class shall be computed using the following formula:

$$SMR\ 1 = [SM_c / S - E_s / S]\ X\ 1 / (1\text{-}T)$$

The SMR for the Large C&I class shall be computed using the following formula:

$$SMR\ 1 = [SM_c / N - E_s / N]\ X\ 1 / (1\text{-}T)$$

Where:

SM_c = An annual budget amount of all costs required for the Company to implement its Commission-approved Smart Meter Plan (SMP) during a compliance year. A compliance year is the 12-month period beginning January 1 of each calendar year and ending December 31 of the same calendar year, except the first compliance year which will also include all smart meter costs incurred prior to January 1, 2011. The annual budget amount is the sum of all direct and indirect capital (e.g., return of and return on applicable smart meter-related investment) and operating (e.g, applicable O&M and taxes) costs, including all deferred design and development costs, and general administrative costs, required to implement the Company's SMP in the compliance year.

The capital and operating costs of each SMP initiative available to only one customer class will be directly assigned to that customer class. The costs of SMP initiatives which cannot be directly assigned to one customer class will be assigned based on the ratio of number of meters assigned to the classes, divided by the number of meters for the entire system.

N = Number of Bills (Customers X 12) per Year

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SMART METER RIDER – PHASE 1 (CONTINUED)

Es = Net over or undercollection of the SMR 1 charges as of the end of the 12-month period ending June 30 of each year. Reconciliation of the SMR 1 will be conducted separately for each of the three customer classes based upon the annual EE&C and SMP budgets for each customer class. Interest shall be computed monthly at the legal rate of interest of 6% from the month the over or undercollection occurs to the effective month that the overcollection is refunded or the undercollection is recouped.

S = The Company's total delivered KWH sales to customers in each customer class who receive distribution service under this tariff (including distribution losses), projected for the computation year.

T = The total Pennsylvania gross receipts tax rate in effect during the billing period, expressed in decimal form.

The SMR 1 shall be filed with the Pennsylvania Public Utility Commission (Commission) by August 1 of each year. The SMR 1 charge shall become effective for distribution service provided to all customers on or after the following January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. Upon determination that a customer class's SMR 1, if left unchanged, would result in a material over or undercollection of Smart Meter costs incurred or expected to be incurred during the current 12-month period ending December 31, the Company may file with the Commission for an interim revision of the SMR 1 to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

Minimum bills shall not be reduced by reason of the SMR 1, nor shall charges hereunder be a part of the monthly rate schedule minimum. The SMR 1 shall not be subject to any credits or discounts. The State Tax Adjustment Surcharge (STAS) included in this Tariff is applied to charges under this Rider.

The Company shall file a report of collections under the SMR 1 within thirty (30) days following the conclusion of each computation-year quarter. These reports will be in a form prescribed by the Commission. The third-quarter report shall be accompanied by a preliminary forecast of the SMR 1 for the next computation year.

Application of the SMR 1 shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the SMR 1 and the costs included therein.

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SMART METER RIDER – PHASE 1 (CONTINUED)

SMART METER RIDER – PHASE 1 CHARGE

Charges under the SMR 1 for the period January 1, 2014 through December 31, 2014, as set forth in the applicable Rate Schedules.

Customer Class	**Large C&I**	**Small C&I**	**Residential**
Rate Schedule / Charge	LP-4, LP-5, LPEP, and L5S $1.29/Bill	GS-1, GS-3, IS-1 (R), BL, and GH-2 (R) $0.00002/KWH	RS and RTS (R) $0.00013/KWH

Small I&C – Street Lights									
Rate Schedule/ Charge	SA	SM (R)		SHS		SE	TS (R)	SI-1 (R)	
	$/Lamp	Nominal Lumens	$/Lamp	Nominal Lumens	$/Lamp	$/KWH	$/Watt	Lumens	$/Lamp
	0.001	3,350	0.001	5,800	0.001	0.00002	0.00001	600	0.000
		6,650	0.002	9,500	0.001			1,000	0.001
		10,500	0.002	16,000	0.001			4,000	0.002
		20,000	0.003	25,500	0.002				
		34,000	0.006	50,000	0.004				
		51,000	0.008						

SMART METER RIDER - PHASE 2

A Phase 2 Smart Meter Rider (SMR 2) shall be applied, on a non-bypassable basis, to charges for electricity supplied to customers who receive distribution service from the Company under this Tariff.

The SMR 2 shall be computed separately for each of the following three customer classes:

(1) Residential: Consisting of Rate Schedules RS and RTS (R),
(2) Small Commercial and Industrial (Small C&I): Consisting Rate Schedules GS-1, GS-3, IS-1 (R), BL, SA, SM (R), SHS, SE, TS (R), SI-1 (R), and GH-2 (R), and
(3) Large Commercial and Industrial (Large C&I): Consisting of Rate Schedules LP-4, LP-5, LPEP, and L5S.

The SMR 2, as computed using the formulae described below, shall be included in the distribution charges of the monthly bill for each customer receiving distribution service from the Company and shall be reconciled on an annual basis for undercollections and overcollections experienced during the previous year. Charges set forth in the applicable rate schedules in this tariff have been adjusted to reflect application of the currently effective SMR 2.

The SMR 2 for the Residential class, the Small C&I class, and the Large C&I class shall be computed using the following formula:

$$\text{SMR 2} = ((SM_c - E_s) \ / \ N\ ) \times 1 \ / \ (1\text{-}T)$$

Where:

SM_c = A quarterly actual amount of all costs required for the Company to implement its Commission approved Smart Meter Plan (SMP) during a compliance period. The initial SMR 2, effective April 1, 2015, shall be calculated to recover costs not previously reflected in PPL Electric's rates or rate base and that have been recorded on the Company's books and records between January 1, 2015 and February 28, 2015. Thereafter, the SMR 2 will be updated on a quarterly basis to reflect costs during the three-month period ending one month prior to the effective date (a compliance period) of each SMR 2 update. The quarterly amount is the sum of all direct and indirect capital (e.g. return of and return on applicable smart meter-related investment) and operating (e.g., applicable O&M and taxes (dependent upon the Company's tax net operating loss carryforward)) costs, including all deferred design and development costs, and general administrative costs, required to implement the Company's SMP in the compliance period. Deferred design and development costs incurred during 2014 will be recovered over three years.

The costs of SMP will be allocated to the total number of meters on PPL Electric's system based on the ratio of investment in meters for each rate class.

N = Number of Bills (Customers X 3) per Quarter

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SMART METER RIDER - PHASE 2 (CONTINUED)

Es = Net over or undercollection of the SMR 2 charges as of the end of the 12-month period ending December 31 of each year. Reconciliation of the SMR 2 will be conducted separately for each of the three customer classes based upon the annual revenue received compared to the actual SMP costs. Interest shall be computed monthly at the residential mortgage lending rate specified by the Secretary of Banking in accordance with Loan Interest and Protection Law (41 P.S. §§ 101, *et. seq.*) from the month the over or undercollection occurs to the effective month that the overcollection is refunded or the undercollection is recouped.

T = The total Pennsylvania gross receipts tax rate in effect during the billing period, expressed in decimal form.

The SMR 2 shall be filed with the Pennsylvania Public Utility Commission (Commission) and served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Auditing, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update. The changes in the SMR 2 rate will occur as follows:

Effective Date of Change	Date to which SMR 2 - Eligible Costs Reflected
April 1, 2015	January 1 – February 28, 2015
July 1, 2015	March 1 – May 31, 2015
October 1, 2015	June 1 – August 31, 2015
January 1, 2016	September 1 – November 30, 2015

Minimum bills shall not be reduced by reason of the SMR 2, nor shall charges hereunder be a part of the monthly rate schedule minimum. The SMR 2 shall not be subject to any credits or discounts. The State Tax Adjustment Surcharge (STAS) included in this Tariff is applied to charges under this Rider.

The Company shall file a report of collections under the SMR 2 within thirty (30) days following the conclusion of each computation-year quarter. These reports will be in a form prescribed by the Commission.

Application of the SMR 2 shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the SMR 2 and the costs included therein.

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SMART METER RIDER - PHASE 2 (CONTINUED)

SMART METER RIDER - PHASE 2 CHARGE

Charges under the SMR 2 for the period April 1, 2015 through June 30, 2015, as set forth in the applicable Rate Schedules.

Customer Class	Large C&I	Small C&I	Residential
Rate Schedule / Charge	LP-4, LP-5, LPEP, and L5S $X.XX/Bill	GS-1, GS-3, IS-1 (R), BL, and GH-2 (R) $X.XX/Bill	RS and RTS (R) $X.XX/Bill

Small I&C – Street Lights									
	SA	SM (R)		SHS		SE	TS (R)	SI-1 (R)	
Rate Schedule/ Charge	$/Bill	Nominal Lumens	$/Bill	Nominal Lumens	$/Bill	$/Bill	$/Bill	Lumens	$/Bill
	X.XX	3,350	X.XX	5,800	X.XX	X.XX	X.XX	600	X.XX
		6,650	X.XX	9,500	X.XX			1,000	X.XX
		10,500	X.XX	16,000	X.XX			4,000	X.XX
		20,000	X.XX	25,500	X.XX				
		34,000	X.XX	50,000	X.XX				
		51,000	X.XX						