BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

JOINT PETITION OF METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY FOR APPROVAL OF THEIR SMART METER DEPLOYMENT PLAN	: **DOCKET NOS.**

JOINT PETITION OF METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY

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Dated: December 31, 2012

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Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (each individually a "Company" and collectively, the "Companies") hereby petition the Commission for approval of their Smart Meter Deployment Plan ("Deployment Plan"). Specifically, the Companies request that the Commission: (1) find that the Deployment Plan satisfies the requirements of Act 129, 66 Pa.C.S. § 2807(f)(1)-(f)(3) and the Commission's June 24, 2009 Implementation Order; (2) approve the Companies' proposed procurement and deployment of approximately 2.1 million smart meters, over 98 percent of which will be installed by the end of 2019; (3) authorize the Companies to continue to recover smart meter costs through their Smart Meter Technologies Charge Riders, including an additional $5.1 million for previous West Penn expenditures; and (4) authorize the Companies to create a regulatory asset for their meter stock that will be replaced by smart meters ("Legacy Meters").

The Companies have taken a measured and deliberate approach in developing the Deployment Plan to achieve a successful deployment throughout their service territories. First, the Companies convened internal and external experts to assess both the Companies' existing technology infrastructure and the current state of smart meter technologies. Second, the Companies selected smart meter technologies and vendors after a rigorous information gathering, evaluation and testing process. Third, the Companies will implement a large scale "Solution Validation" process that involves the installation of up to 60,000 meters in Penn Power's service territory in order to address potential "ramp up," functionality and communication infrastructure issues in a contained and controlled environment, thereby minimizing the costs and risks of full-scale deployment and potential customer frustration. Finally, full scale deployment is expected to be substantially complete by 2019, three years earlier than Met-Ed, Penelec and Penn Power had originally proposed in their 2009 Smart Meter Implementation Plan filed at Docket No. M-2009-2123950.

I. INTRODUCTION

1. Met-Ed is a wholly owned subsidiary of FirstEnergy Corp. that provides service to approximately 555,000 electric utility customers in eastern Pennsylvania. Penelec is a wholly owned subsidiary of FirstEnergy Corp. that provides service to approximately 584,000 electric utility customers in central and western Pennsylvania. Penn Power is a wholly owned subsidiary of Ohio Edison Company, which, in turn, is a wholly owned subsidiary of FirstEnergy Corp. Penn Power provides service to approximately 160,000 electric utility customers in western Pennsylvania. West Penn is a wholly owned subsidiary of Allegheny Energy, Inc., which, in turn, is a wholly owned subsidiary of FirstEnergy Corp. West Penn provides service to almost 716,000 electric utility customers in western Pennsylvania.

2. Act 129 was signed into law by former Pennsylvania Governor Edward G. Rendell on October 15, 2008 and, amongst its other requirements, directed electric distribution companies ("EDCs") with more than 100,000 customers to file plans with the Commission that provided for the installation of smart meter technology throughout their service territories over a period not to exceed 15 years. It also required EDCs to install, after their Commission authorized grace period, smart meters in new construction and to furnish smart meter technology to any costumer upon request if the customer agrees to pay the applicable cost. *See* 66 Pa.C.S. § 2807(f)(2).

3. An EDC is entitled to full and current recovery of its reasonable and prudent costs of providing smart meter technology, net of operational and capital cost savings actually realized by the EDC from the use of smart meter technology. 66 Pa.C.S. § 2807(f)(7). Such costs include annual depreciation of capital costs over the life of the smart meter technology and the costs of any system upgrades required to enable the use of the smart meter technology. *Id.* EDCs are authorized to recover their net costs, upon their election, either: (1) on a current basis through a Section 1307 reconcilable surcharge; or (2) in base rates with authority to defer costs incurred between base rate cases. *Id.*

4. On June 24, 2009, the Commission entered an order establishing standards and providing guidance for implementing the smart meter requirements of Act 129. *See Smart Meter Procurement and Installation*, Docket No. M-2009-2092655 (Order entered June 24, 2009) ("Implementation Order"). The Commission identified fifteen functionalities that it believed smart meter systems should support.[1] It also established a 30-month "Grace Period" after a

1 Act 129 specified six mandatory functions and the Commission added nine more. The Implementation Order provided, however, that EDCs could seek a waiver of one or more of the additional nine functionalities if their adoption was shown not to be cost-effective.

smart meter plan is approved during which an EDC was expected to "assess its needs, select technology, secure vendors, train personnel, install and test support equipment and establish a detailed meter deployment schedule …." Finally, and in accordance with Act 129, the EDCs were directed to file initial smart meter plans by no later than August 14, 2009.

5. On August 14, 2009, Met-Ed, Penelec and Penn Power filed their joint Smart Meter Implementation Plan ("2009 SMIP"). In their filing the Companies stated they would use the first 24 months of the Grace Period as an "Assessment Period" to assess needs and select technology and vendors, and would then submit a deployment plan setting forth their proposed full scale deployment plan. By Order entered June 9, 2010 at Docket No. M-2009-2123950, the Commission approved the 2009 SMIP, with several minor modifications. The Deployment Plan, attached as Exhibit A, is the result of the work performed during the Assessment Period.

6. West Penn also filed a Smart Meter Implementation Plan ("WP SMIP") on August 14, 2009. However, during the pendency of the proceeding in which the WP SMIP was being assessed, FirstEnergy and West Penn's corporate parent, Allegheny Energy Inc., announced their intent to merge. As a result, the WP SMIP filing was reassessed. Eventually the parties to the WP SMIP proceeding negotiated and submitted a document entitled "Amended Joint Petition for Settlement of All Issues" ("Joint Settlement"). The Joint Settlement, among other things, provided for a substantial deceleration in the deployment of smart meters from the schedule originally proposed by West Penn and obligated West Penn to conduct several analyses regarding the relative costs and benefits of smart meter deployment. The Commission adopted the ALJ's Initial Decision and approved the Joint Settlement by Order entered June 30, 2011 at Docket No. M-2009-2123951.

7. On May 25, 2012, the Companies requested a filing extension for the Deployment Plan until the end of 2012 to allow for the testing and analysis of soon-to-be-released improved smart meter technology. The Commission granted that request by letter dated June 28, 2012.

8. This Petition describes the development of the Deployment Plan, the Companies' plans for smart meter deployment, and the costs and net benefits of the Deployment Plan. In further support of their Deployment Plan, the Companies are submitting the following statements, which are attached hereto and incorporated by reference:

- **Met-Ed/Penelec/Penn Power/West Penn Statement No. 1,** Direct Testimony of John Dargie (Overview of Act 129, the Companies, and the Deployment Plan).
- **Met-Ed/Penelec/Penn Power/West Penn Statement No. 2,** Direct Testimony of David W. Iorio (Selection of smart meter technology and vendors, recommended smart meter solution deployment schedule).
- **Met-Ed/Penelec/Penn Power/West Penn Statement No. 3,** Direct Testimony of Kevin A. Klein (Smart meter technology assessment, recommended smart meter technology solution, solution validation stage, public cellular backhaul, system security, meter access and access to data).
- **Met-Ed/Penelec/Penn Power/West Penn Statement No. 4,** Direct Testimony of George L. Fitzpatrick (Analyses of alternative smart meter deployment schedule scenarios, plan costs and estimated potential savings, communication, change management and training strategies).

- **Met-Ed/Penelec/Penn Power/West Penn Statement No. 5,** Direct Testimony of Raymond E. Valdes (cost recovery, customer bill impact and presentation, Legacy Meter accounting treatment, EDI issues).

II. DEVELOPMENT OF THE DEPLOYMENT PLAN

9. In order to develop the Deployment Plan, the Companies assembled a team (the "SMIP Team") of employees and expert consultants (IBM and Black & Veatch) to develop a smart meter solution that provided the functionality required by Act 129 and the Implementation Order (to the extent cost-effective) and also could be fully implemented by or before 2025 at a reasonable cost. The team was divided into substantive work groups, which addressed a variety of subjects, including the current state of the Companies' business units, vendor selection, technology evaluation, and customer awareness.

10. In the course of their development activities, the subgroups consulted with technology vendors and visited several other utilities that have deployed smart meter systems to discuss lessons learned. The team also conducted market research and held meetings with stakeholders to gain a better understanding of their views on smart meter issues.

11. Overall, the recommended smart meter solution design was based on an analysis of: (1) the current state of smart meter technology; (2) technology "baselines" for the Companies; and (3) the diverse nature of the Companies' service territories, both in terms of density and terrain. The key components of the solution are: (1) smart meters; (2) a "head end" for communication with all meters and collection of meter data; (3) a meter data management system ("MDMS") to receive, store, and process data from the head ends; and (4) use of a public backhaul communications network for communications between the meter network and the Companies' information systems.

12. With an initial design solution selected, the Companies began to investigate potential vendors. The Company managed a rigorous selection process, which included issuing Requests for Information, Requests for Proposals ("RFPs"), requesting oral vendor presentations, and testing equipment and technology in test labs and "in the field" in the Met-Ed and West Penn service territories.

13. Based upon the results of this selection process, the Companies ultimately selected the following vendors:

Smart Meter System Component	Selected Vendor
Meter Vendor	Itron
Head End Vendor	Itron
MDMS	Itron
Backhaul	AT&T / Verizon

III. PROPOSED DEPLOYMENT SCHEDULE

14. The Companies propose to deploy their selected smart meter solution in three stages: (1) the Post-Grace Period ("PGP") Stage; (2) the Solution Validation Stage; and (3) the Full-Deployment Stage.

(1) Post-Grace Period Stage: Commencing on January 1, 2013 and concluding with the completion of deployment, smart meters will be provided for all new service applications received after December 31, 2012 ("New Construction") and to customers who request a smart meter prior to the infrastructure being built in their area ("Early Adopters"), provided that the

Early Adopter customer pays the incremental costs of a meter and installation.[2] During the early part of this stage, the Companies will also be negotiating final terms and conditions with selected vendors and undertaking other pre-deployment activities.

(2) Solution Validation Stage: Expected to commence in late 2013 and ending in early 2017, the Companies will construct network infrastructure and up to 60,000 meters will be installed and evaluated in Penn Power's service territory as a "mini-system," with lessons learned applied to minimize future costs, risks and customer frustration during full-scale deployment. Penn Power was selected because it includes the types of challenges the SMIP Team anticipates encountering during full deployment and also has information systems that are more closely linked to the information systems of West Penn.

(3) Full-Scale Deployment Stage: Expected to commence in early 2017, the Companies will complete installation of all smart meters to all remaining customers during this stage. The Companies anticipate installation of approximately 98.5 percent of all smart meters between January 1, 2014 and December 31, 2019 ("Deployment Period"). The remaining meters (such as those located in low-density areas difficult to reach via radio frequency, such as hunting cabins) will be installed no later than 2022, and perhaps earlier should further technological improvements occur during full-scale deployment.

15. As described by Mr. Fitzpatrick, the Companies reviewed several alternative deployment scenarios and selected the schedule described above because: (1) it is relatively low cost; (2) it has reasonable potential technology and cost risk; and (3) overall, it is the scenario most likely to achieve the ultimate goal – the deployment of a comprehensive, well tested cost effective smart meter system in a reasonable timeframe.

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2 Tariff provisions implementing the Companies' proposals for New Construction and Early Adopters have been approved by Commission Secretarial Letter dated December 21, 2012 at Docket Nos. R-2012-2332803, R-2012-2332776, R-2012-2332785, and R-2012-2332790.

16. While the recommended meters upon installation will be *capable* of providing all meter functionality required by Act 129 and the Commission's Implementation Order, *actual* functionality will become available upon completion of the communication network in the area, currently expected to lag installation by approximately 3 months. Meters installed for Early Adopters will use a Point-To-Point ("PTP") smart meter and will meet the basic Act 129 functionality requirements. This smart meter will communicate via a public cellular network and will provide on-line access to validated meter data within 24-48 hours and access to unvalidated meter data via a direct access interface to a customer device that is part of a home area network. Meter reads for billing purposes will continue to be done manually using existing meter reading and billing procedures until the smart meter network infrastructure becomes available at the customer's location and the PTP meter is replaced with the smart meter selected as part of the smart meter technological solution.

IV. COSTS AND PROJECTED SAVINGS

17. The Companies estimate that the total 20 year life cycle costs of the Deployment Plan will be approximately $1.258 billion (nominal dollars), with approximately $752 million (nominal) incurred during the Deployment Period. As described in detail in the testimony of Mr. Fitzpatrick, the total Deployment Plan cost is comprised of the following major cost components: (1) Meter and Local Area Network; (2) Network and Network Management; (3) Information Technology; (4) Program Management; (5) Systems Integration; (6) Change Management; and (7) Business Staffing Requirements.

18. The cost estimates for components 1 - 4 were based on price quotes included in RFP responses from various vendors. Business Staffing and Systems Integration costs were based on the Companies' estimated internal requirements as well as IBM's experience with other

utility smart meter deployments. Change Management cost estimates, which includes costs for communications and training, were developed by IBM and Black & Veatch based on their previous experiences with smart meter deployment and in consultation with the Companies' SMIP team leadership.

19. The Companies estimate the potential savings generated through the implementation of the Deployment Plan over the 20 year life cycle of the project to be approximately $406 million (nominal dollars). These savings will occur predominantly in meter reading and meter service activities, but also in the areas of back office, customer accounting, and contact center costs and, to the extent realized, will be flowed through to customers as credits to the Companies' respective Smart Meter Technologies Charge Riders (see discussion, *infra*).

V. COST RECOVERY

20. The Companies have each implemented a Commission-approved Smart Meter Technologies Charge ("SMT-C") Rider[3] and are not proposing any major revisions to those Riders. However, should the Commission authorize West Penn's $5.1 million claim for recovery of prior period smart meter plan costs, discussed *infra*, West Penn's SMT-C will need to be amended to reflect recovery of those additional costs.

21. The Companies have two proposals regarding costs related to their Legacy Meters. First, the Companies are requesting Commission approval to create a regulatory asset for these meters, with a recovery schedule set equal to the remaining depreciable lives per the respective Company's Annual Depreciation Reports as filed with and approved by the

[3] *See* Docket No. M-2009-2123950 (Order entered June 9, 2010) (Met-Ed, Penelec and Penn Power SMT-C Rider effective August 1, 2010); Docket No. M-2009-2123951 (Order entered June 30, 2010) (West Penn SMT-C Rider effective September 1, 2011).

Commission pursuant to 52 Pa. Code §§ 73.1-73.9, and with continued recovery through base rates. Second, because the removal of the Legacy Meters is part of the installation of the smart meters, the Companies are seeking Commission approval to include the cost of removal for these meters as a recoverable O&M expense in the SMT-C of each Company's SMT-C Rider.

22. Finally, West Penn is proposing to recover an additional $5.1 million through its SMT-C Rider for expenditures made to develop a smart meter plan in 2009-2010. The West Penn Joint Settlement at Docket No. M-2009-2123951 noted that West Penn expended approximately $45.1 million between 2009 and 2010 for the development of a smart meter deployment plan, of which the settling parties agreed that initially $40 million could be immediately recovered through the SMT-C Rider. Recovery of the additional $5.1 million through the SMC-C Rider, which represented certain costs related to a customer information system, was challenged. However, it was agreed that West Penn would be permitted to seek recovery of the $5.1 million disputed amount in its next distribution base rate case or as part of the SMT-C Rider in connection with its filing of a smart meter deployment plan.

23. As described in the testimony of Mr. Raymond E. Valdes, the Companies have benefited from the full $45.1 million expenditure. The $5.1 million sum was an integral part of the $45.1 million sum and could not have been avoided in Phase I and Phase II of the West Penn effort. Act 129 permits recovery of the $5.1 million and the Phase I and Phase II deliverables proved useful and beneficial to the overall development of the smart meter solution being proposed in this case.

24. West Penn proposes to recover the entire $45.1 million of costs incurred between 2009 and 2010 associated with the development of a smart meter deployment plan and requests that the Commission authorize West Penn to include an additional $5.1 million to the previously

approved recovery of $40 million, to be collected over the remaining amortization period concluding on February 28, 2017.

VI. INTERNAL AND EXTERNAL COMMUNICATIONS, CHANGE MANAGEMENT AND TRAINING

25. The Companies are currently developing an internal and external communications plan ("Comm Plan"), a change management transition plan and a training plan and have gathered lessons learned in each of these areas from several utilities in various stages of smart meter deployment. Because technology and vendors were selected during the fourth quarter of 2012, none of these plans are finalized, but are expected to be complete before the beginning of the Solution Validation Stage, which currently is anticipated to start during the fourth quarter of 2013. Below is a description of the strategies underlying each of these plans.

26. The primary goals of the Comm Plan are to: (i) keep customers, city officials and employees updated on Deployment Plan progress; (ii) manage expectations, both as to installation and potential for customer savings; and (iii) alleviate concerns regarding privacy, access to customer information and other smart meter related issues. The Companies expect customer communications will be accomplished through a variety of channels, such as print and radio advertising, customer and employee letters, websites and web portals, webinars, social and digital media, email, text messaging, and online and hard copy toolkits. The Companies will also educate employees through company-wide emails, videos and briefings, as well as employee education on relevant topics through tutorials and self-learning tools. The Comm Plan will be designed with the flexibility necessary to modify its content and focus during the Deployment Period as conditions warrant. The Companies intend to work through the stakeholder process to finalize the content of communications to various target audiences.

27. The Companies are in the process of finalizing their Change Management Plan. This plan consists of four phases: (i) strategy development; (ii) planning; (iii) pre-deployment; and (iv) deployment. It will be supported by a change management team comprised of executive and middle management sponsors, along with select employees who will act as "Change Champions." The goals of this plan are to minimize the extent and duration of the disruption inherent in change, to promote understanding and commitment, and to build the foundation for heightened levels of sustained performance. Because the Companies currently have in place change management processes and protocols that have been proven successful in other major undertakings such as mergers, acquisitions and installations of major systems, the change management team will borrow from these processes and protocols, modifying them as appropriate for the smart meter technology installation.

28. The Companies are in the process of also finalizing their training plan. The organizational readiness team will partner with appropriate work streams and business units to facilitate the flow of information to all audiences impacted by the implementation of the Deployment Plan. Training will be delivered across the various work streams and within impacted business units. Both current and future state assessments have been performed, which highlighted potential gaps in skill sets that will require specific training, depending on the positions affected. The training curriculum will be divided into three categories:

- Level 100: "SMIP Ambassador Training" consisting of general program-level material that is provided in emails, newsletters, meetings, and videos to all affected FirstEnergy employees
- Level 200: "Workforce Development Training" available for anyone interested in smart meters or AMI delivered by classroom and computer-based training that can be used as a prerequisite to smart meter/AMI job role training
- Level 300: "SMIP Training" provided to employees of highly impacted business units. This training focuses on deployment-based and system release-based training, including SMIP deployment information, company, employee and customer benefits, business

process changes, new technologies, systems, and tools, and preparation for the new opportunities and skills demanded by new job roles

29. The training materials are in the process of being developed and are expected to be complete prior to the commencement of the Solution Validation Stage.

VII. CYBER-SECURITY, DATA PRIVACY AND EDI

30. Due to the timing of the selection of the smart meter technology, which occurred during the fourth quarter of 2012, the Companies are still finalizing their cyber-security plan, which will be consistent with current FirstEnergy protocols. This plan will ensure that all systems and hardware are fully secure and that data is protected using nationally recognized protocols and standards. Where vendors are involved, they will be required by Service Level Agreements to adhere to Company and National Institute of Standards and Technology ("NIST") security standards. The smart meter network design will be securable to protect customer data. Company systems will be regularly evaluated for access appropriateness and adequate cyber security controls in accordance with corporate standards developed from ISO 17799 and ISO 27001/2. All smart meter related data communication over the network will be encrypted. The data exchanged between the collectors and the smart meter will be accompanied by authentication in accordance with utility cyber-security best practices. Vendors will implement internal security measures to ensure proper authentication within their networks. Communications between collectors and substations will be encrypted at all points of ingress and egress. The Companies will implement hardware, software and procedural mechanisms that record and examine activity in systems that contain sensitive information. The actions of users that have privileged access to operating systems, databases, key network devices, and the

security devices will be monitored. Using internal and external audit processes, the Companies will regularly monitor and correct security issues.

31. The Companies currently manage the security of customer data such as names, account numbers and addresses. Customer consent is required to release data to third parties. This practice will not change. The Companies will not transport or proliferate customer names, account numbers or addresses through the advanced metering infrastructure network, only interval data. The Companies currently follow several North American Energy Standards Board ("NAESB") and National Institute of Standards and Technology ("NIST") security standards and guidelines regarding advanced metering infrastructure. Privacy policies are published on the Companies' website. In addition, periodic Privacy Impact Assessments ("PIAs") are performed based on associated risks, recent process changes and new systems and applications. These practices will become standard protocols in the smart meter solution.

32. By Order entered December 6, 2012 at Docket No. M-2009-2092655, the Commission established data exchange standards for current business processes. Specifically, the Commission directed that all EDCs subject to the smart meter provisions of Act 129 address standards for attaining real-time ("RT") and time-of-use ("TOU") pricing capabilities, provide the EDC's current capability to provide a minimum of 12-months of historical interval usage data via electronic data interchange ("EDI"), and to incorporate meter-level interval usage data capabilities. The Companies' current processes and procedures accommodate these requirements. The implementation of the Deployment Plan will not change this.

VIII. PROPOSED PROCEDURAL SCHEDULE

33. Because the Deployment Plan is based on an assumption that it will be approved by the Commission no later than September 30, 2013, the Companies propose the following procedural schedule be adopted:

Deployment Plan and supporting testimony filed	December 31, 2012
Prehearing Conference and Intervention Deadline	March 15, 2013
Intervenor Direct Testimony Due	April 5, 2013
Rebuttal Testimony Due	April 26, 2013
Surrebuttal Testimony Due	May 10, 2013
Evidentiary Hearing/Oral Rejoinder (if any)	May 15, 2013
Main Briefs	June 6, 2013
Reply Briefs	June 20, 2013
Recommended Decision	July 25, 2013
Commission Order	September 26, 2013

IX. NOTICE

34. The Companies are serving copies of this filing on the Pennsylvania Office of Consumer Advocate, the Pennsylvania Office of Small Business Advocate, and the Commission's Bureau of Investigation and Enforcement.

35. The Companies respectfully request the Commission publish notice of this filing in the *Pennsylvania Bulletin*, with the above proposed deadline of March 15, 2013, as a deadline for intervention in this proceeding in light of the Companies' proposed schedule. Should the Commission conclude that further notice of this filing is appropriate, the Companies will provide such additional notice as directed by the Commission.

X. CONCLUSION

The Companies request that the Commission enter an order: (1) finding that the Deployment Plan satisfies the requirements of Act 129, 66 Pa.C.S. § 2807(f)(1)-(f)(3) and the Commission's Implementation Order; (2) approving the Companies' proposed procurement and deployment of approximately 2.1 million smart meters, over 98% of which will be installed by the end of 2019; (3) authorizing the Companies to continue to recover smart meter costs through their Smart Meter Technologies Charge Rider, including an additional $5.1 million for previous West Penn expenditures; and (4) authorizing the Companies to create a regulatory asset for their Legacy Meters.

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Dated: December 31, 2012

Exhibit A

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO.

PENNSYLVANIA ELECTRIC COMPANY
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PENNSYLVANIA POWER COMPANY
DOCKET NO.

WEST PENN POWER COMPANY
DOCKET NO.

SMART METER DEPLOYMENT PLAN

DECEMBER 31, 2012

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CHAPTER 1. EXECUTIVE SUMMARY

1.1 Overview

1.1.1 History

On October 15, 2008, former Governor Edward G. Rendell signed House Bill 2200 into law as Act 129 of 2008 ("Act 129"). Among other things, Act 129 directed each electric distribution company ("EDC") with more than 100,000 customers to file a Smart Meter Technology Procurement and Implementation Plan ("SMIP") with the Pennsylvania Public Utility Commission ("Commission") by August 14, 2009. On June 24, 2009, the Commission entered an Implementation Order in which it provided general guidance as to the information to be included in the SMIP. On August 14, 2009, Metropolitan Edison Company ("Met Ed"), Pennsylvania Electric Company ("Penelec"), and Pennsylvania Power Company ("Penn Power") (collectively "PA Companies") submitted their SMIP, which was approved with minor modifications in an Order entered on June 9, 2010 ("SMIP Order"). As part of their SMIP, the PA Companies presented both a short term and long term plan, indicating that they would use the first 24 months of the 30-month Grace Period provided for by the Commission in its Implementation Order (the "Assessment Period") to assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a detailed meter deployment schedule consistent with the statutory requirements.[1] The PA Companies indicated that at the end of the Assessment Period they would submit to the Commission a Smart Meter Deployment Plan that included: (i) a detailed long term timeline, with key milestones; (ii) a smart meter solution; (iii) the estimated costs of such a solution, along with an assessment of benefits; (iv) a network design solution; (v) a communications architecture design solution; (vi) a training assessment and proposed curriculum; (vii) a cost recovery forecast; (viii) a transition plan including communications plan for employees and consumers; and (ix) a detailed, tiered roll-out plan.[2]

Subsequent to the filing of the PA Companies' SMIP, FirstEnergy Corp. ("FirstEnergy"), the PA Companies' parent company, announced its intent to merge with Allegheny Energy Inc. ("Allegheny"). Allegheny owned West Penn Power ("West Penn") which submitted its own smart meter implementation plan to the Commission on August 14, 2009 in Docket No. M-2009-2123951 ("WPP SMIP"). Subsequent to making its filing, West Penn and interested parties, entered into an Amended Joint Petition for Settlement ("Joint Settlement") in

[1] SMIP Order at 13-14.

[2] SMIP Order at 6-7. Upon receiving the SMIP Order, the PA Companies commenced their Assessment Period which, based upon the PA Companies' representations, would make their Deployment Plan due in June 2012.

which West Penn made several commitments that significantly changed its original SMIP filing. Among them was a commitment to decelerate its proposed deployment of smart meters and to submit a Revised SMIP (which is the equivalent of the PA Companies' Deployment Plan) no sooner than June 30, 2012.[3] The Commission approved the Joint Settlement on June 30, 2011 ("WPP Order").

Upon completion of the merger between FirstEnergy and Allegheny, and approval of the Joint Settlement, the smart meter needs of West Penn, along with West Penn's commitments made through the Joint Settlement, were incorporated into the analyses and other work being done by the PA Companies' Smart Meter Implementation Plan team ("SMIP Team") – a core team comprised of employees of the PA Companies (supplemented by Allegheny employees post merger), representing a variety of interests and skill sets, subject matter experts from the consulting firms of IBM, Inc. ("IBM") and Black & Veatch Corp. ("Black & Veatch"), and various technology vendor representatives knowledgeable in areas involving key components and process designs of the core smart meter infrastructure solution. Work performed by West Penn when preparing the WPP SMIP was incorporated into the overall development of this Deployment Plan, thus reducing the amount of work that otherwise would have been necessary to complete such development.

While the SMIP Team was in the process of finalizing the Deployment Plan for filing in June 2012, several smart meter vendor finalists independently indicated their intent to release improved smart meter system technology in the late spring of 2012. It was expected that this improved technology would provide enhanced two-way communication capability and flexibility throughout the footprint of the PA Companies and West Penn (together, the "Companies"), and would provide expanded interface capabilities with potential Smart Grid applications in the future. Because of its imminent release, the SMIP Team felt compelled to assess the improved technology before making its final smart meter recommendations. Therefore, in June 2012, the Companies requested and received an extension of their Assessment Period through December 31, 2012 -- the end of the PA Companies' Grace Period -- so that the team could test this then soon-to-be-released technology in order to determine if (i) it properly interfaced with other smart meter infrastructure equipment being considered; and (ii) it indeed had the improvements promised by the vendors. Testing of this improved technology occurred during the second half of 2012 and the results

[3] For a complete list of the commitments made by West Penn, see West Penn's 2011 SMIP Status Report, filed with the Commission on August 31, 2011 in Docket No. M-2009-2123951.

were assessed as part of the technology selection process, which is more fully discussed in Chapter 2.

This Deployment Plan is based upon the most current available information and sets forth a plan that will provide approximately 98.5 percent of all customers within the FirstEnergy Pennsylvania footprint with smart meters no later than the end of 2019, with the remaining 1.5 percent being installed no later than 2022. The projected cost of this Deployment Plan is approximately $1.258 billion over a 20 year life cycle of the project on a nominal basis, and approximately $694 million on a net present value ("NPV") basis after netting estimated potential savings of approximately $406 million (NPV). Approximately $750 million (nominal) will be spent during the six year construction and meter deployment period that is expected to start on January 1, 2014 and end on December 31, 2019 ("Deployment Period"), assuming the Commission approves this Plan by September 30, 2013.

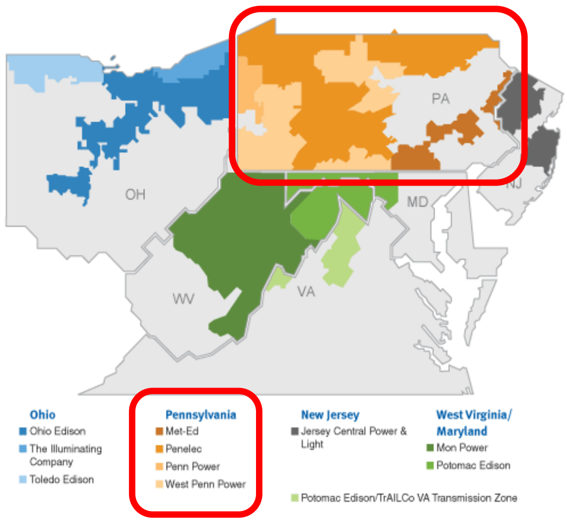
Chapter 2 explains in more detail the work performed to develop this Deployment Plan. Chapter 3 describes the recommended solution and its compliance with Act 129 and Commission directives. Chapter 4 addresses the cost of implementing this Deployment Plan, the estimated savings that the Companies may realize during the 20 year life of the plan and how these savings will be tracked. Chapter 5 addresses cost recovery issues and how the amounts to be included in each of the Companies' respective Commission-approved riders will be calculated. It also sets forth the estimated bill impacts for the various customer classes within each of the Companies and addresses several other rate and regulatory issues. Finally, Chapter 6 discusses the other deliverables promised in the PA Companies' SMIP and the West Penn Joint Stipulation.

1.2 About the Companies

Met-Ed, Penelec, Penn Power and West Penn are wholly-owned subsidiaries of FirstEnergy Corp., and make up the FirstEnergy Pennsylvania footprint.[4] With its ten electric utility operating companies, FirstEnergy operates one of the largest investor-owned electric utilities in the United States, serving approximately 6 million customers over an approximately 65,000 square-mile service territory within Ohio, Pennsylvania, New Jersey, Maryland and West Virginia.

[4] West Penn is a subsidiary of Allegheny Energy Inc., which, along with the PA Companies and other entities, is a first tier subsidiary of FirstEnergy.

Figure 1.1 FirstEnergy Pennsylvania Service Territories



Customer Class	Projected Average Customer Class Count For the Twelve Months Ending December 31, 2013			
	Met-Ed	Penelec	Penn Power	West Penn
Residential	489,495	501,138	140,393	619,826
Commercial	65,082	81,078	18,987	93,309
Industrial	832	866	151	2,744
Total	**555,409**	**583,583**	**159,531**	**715,879**

3

1.2.1 Size and Nature of Each Territory

Below is a brief description of each of the Companies' service territories.

Metropolitan Edison

Met-Ed is a wholly-owned subsidiary of FirstEnergy. It serves approximately 555,000 electric utility customers over 3,570 square miles in southern and southeastern Pennsylvania. Approximately 88% of its customers are residential customers and about 12% are commercial and industrial customers. Meter densities are as follows: 3% with 10 end points or fewer per square mile; 50.1% with 11-100 end points per square mile; 27.2% with 101-200 end points per square mile; and 19.7% with more than 200 end points per square mile.

Penelec

Penelec is a wholly-owned subsidiary of FirstEnergy. It serves approximately 584,000 customers over approximately 17,600 square miles in northern, northwest, and central Pennsylvania. Approximately 86% of its customers are residential customers and about 14% are commercial and industrial customers Meter densities are as follows: 15% with 10 end points or fewer per square mile; 45.4% with 11-100 end points per square mile; 25.5% with 101-200 end points per square mile; and 14.1% with greater than 200 end points per square mile.

West Penn Power

West Penn is a wholly-owned subsidiary of Allegheny, which is a wholly-owned subsidiary of FirstEnergy. It serves almost 716,000 customers over approximately 10,300 square miles in southwest, north central, and south central Pennsylvania. Approximately 86% of its customers are residential customers and about 14% are commercial and industrial customers. Meter densities are as follows: 2% with 10 end points or fewer per square mile; 44% with 11-100 end points per square mile; 41% with 101-200 end points per square mile; and 13% with greater than 200 end points per square mile.

Penn Power

Penn Power is a wholly-owned subsidiary of Ohio Edison that is, in turn, a wholly-owned subsidiary of FirstEnergy. Penn Power serves about 160,000 customers over approximately 1,100 square miles in western Pennsylvania. Approximately 88% of its customers are residential customers and about 12% are commercial and industrial customers. Meter densities are as follows: 8.9% with 10 end points or fewer per square mile; 55.3% with 11-100 end points per square mile; 27.7% with 101-200 end points per square mile; and 8.1% with greater than 200 end points per square mile.

The overall diversity of the Companies' service territory terrain creates significant challenges specific to the Companies. Additional challenges, not unique to the Companies, include the need to develop a deployment plan in an environment that continues to change as technology improves, vendors merge, and standards and guidelines are established on a regional and national level. These and many other factors were considered when designing the smart meter solution included in this Deployment Plan.

1.3 Objectives and Assumptions

1.3.1 Objectives

The objectives surrounding the development of this Deployment Plan were as follows:

1. Submit a plan that complies with Act 129, the Implementation Order, and the various commitments made by any of the Companies.

2. Minimize the likelihood of stranded investment through obsolescence by performing robust evaluation and analysis and adhering to evolving national smart metering guidelines and policies.

3. Present a plan that provides the Companies with full cost recovery, including fair returns for any capital employed, while allowing them sufficient financial flexibility to provide for their other not-insubstantial capital requirements and obligations to shareholders.

4. Develop a strategic and cost effective deployment plan that will maximize early benefits taking into account risk and related costs.

5. Develop a workable process to track, measure and verify benefits arising from the implementation of this Deployment Plan.

1.3.2 Assumptions:

The development of this Deployment Plan was based on the following assumptions:

1. Act 129 calls for 100% customer deployment of smart meters with an implementation timeline of up to 15 years from the date of approval of the SMIP Plan. There will be no opt-out for customers.

2. Time-of-Use ("TOU") and Real-Time-Pricing ("RTP") rates will be in place consistent with Pennsylvania law and the Commission's Implementation Order.

3. Full and timely cost recovery of all costs associated with the evaluation, development, deployment and operation of a smart metering system will be approved.

4. After their grace period, the Companies will install smart meters in all new construction and upon customer request, provided that the latter pays for the incremental cost of such meters and related installation.

5. None of the functionality provided through a smart meter installed in new construction will be available until the infrastructure needed for two-way communication is built in the area.

6. The smart meter solution is designed to integrate with legacy systems such as SAP to the practical degree possible.

7. All smart meters must be working no later than 2025.

1.4 The Deployment Plan Development

Upon approval of the PA Companies' SMIP, the SMIP Team commenced work on this Deployment Plan. The team was subdivided into nine substantive subgroups, or workstreams: (i) Solution Framework; (ii) Current State; (iii) Vendor Strategy; (iv) Technology Evaluation and Test Lab; (v) Future State; (vi) Network Communications; (vii) External Communications and Consumer Awareness Strategies; (viii) Change Management and Training; and (ix) a Project Management Office. The PA Companies included in their Status Report filed with the Commission on July 27, 2011 at Docket No. M-2009-2123950 an outline of the major tasks and timelines during which each of the tasks for each of the workstreams was to be performed.

During the Assessment Period, the SMIP team reviewed numerous documents, including the PA Companies' SMIP, the Commission's Implementation Order, the Pa Companies' SMIP Order, Act 129, and the West Penn Joint Settlement documents and related Commission Orders, so as to ensure that this Deployment Plan complies with Act 129, Commission directives, and all of the commitments made by any of the Companies. The SMIP Team also held stakeholder meetings, including several with those interested in data access and sub-hourly metering, and others with parties interested in low income and other vulnerable customer issues. The SMIP Team held discussions with employees and management of the Companies from all affected business groups, and with employees of other Pennsylvania EDCs who were responsible for those EDCs' smart meter projects. They participated in several utility site visits both within and outside of Pennsylvania, and held numerous discussions with out-of-state utilities that have smart meter programs in various forms and stages. The team sought Requests for Information ("RFIs") from major system and equipment vendors and then Requests for Proposals ("RFPs") from vendors resulting from the RFIs and subsequent testing. Details surrounding both the development of this Deployment Plan and the vendor selection process are set forth in Chapter 2. Based upon this work, the Companies are proposing the solution set forth below.

1.5 The Recommended Solution

The recommended solution includes the following major components:

Smart meters – The meters collect, store, and transmit total consumption data, interval data, and meter events to core applications after configuration, and communicate with Home Area Networks (HANs).

Meter Data Management System (MDMS) – 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. An MDMS may be integrated with utility billing and customer care software (such as SAP's solution for utilities which is used by the PA Companies).

Head End/collection engine – The Head End/collection software collects and delivers information from the meters via the collectors to the MDMS. A proprietary local area network ("LAN") is often used for communications between the meters and the collectors.

"Backhaul" communications network (external) – This network (typically a "wide area network") is the communication system between the collectors and the Head End and includes data center equipment and control software.

Home Area Network ("HAN") – The HAN is a network contained within a user's home that communicates information to in-home devices (IHDs) such as in-home displays.

A more detailed discussion of the recommended solution can be found in Chapter 3.

1.6 The Deployment Schedule and Functionality

The Companies are recommending a phased deployment strategy which anticipates three distinct stages: (i) the Post Grace Period ("PGP") Stage; (ii) the Solution Validation Stage; and (iii) the Full-Scale Deployment Stage.

The PGP Stage, which commences on January 1, 2013 and concludes with the completion of deployment, currently scheduled by December 31, 2022, addresses not only the need to provide smart meters for all new service requests received on or after January 1, 2013 ("New Construction") and for all customers requesting a smart meter prior to their scheduled installation date ("Early Adopters"), but also addresses contract negotiations, final RFPs and other pre-deployment activities.

New Construction/Early Adopters: For new construction for which a temporary or permanent service application is received on or after January 1, 2013, the customer will be provided with a RF smart meter included in the recommended technology solution, which will eventually be able to communicate with the smart meter network infrastructure. Customers will not be billed additional fees for the meter or other installation costs beyond those charged to all metered customers through the Smart Meter Technologies Charge Rider. During the period between smart meter installation and the build-out of the smart meter network in the area where a New Construction smart meter installation occurs, neither the communication functions of the meter nor smart meter functionality will be available and meter reads will be done manually using existing meter reading and billing procedures.

For Early Adopters, once the customer pays the incremental costs for the meter and related installation,[5] a Point-To-Point ("PTP") smart meter that meets the basic Act 129 functionality requirements will be installed. This smart meter will communicate via a public cellular network and will provide on-line access to validated meter data within 24-48 hours and access to unvalidated meter data via a direct access interface to a device that is part of the Home Area Network.[6] Meter reads for billing purposes will continue to be done manually using existing meter reading and billing procedures until the smart meter network infrastructure becomes available at the customer's location and the PTP meter is replaced with the smart meter selected as part of the smart meter technological solution.

Contract Negotiation/RFPs: During the period between the filing of the Deployment Plan with the Commission and approval of the plan by the Commission (anticipated to be by September 30, 2013), the SMIP Team will negotiate final terms and conditions with the selected vendors and select a Systems Integrator ("SI") and Project Management Office ("PMO") through the RFP process described in Chapter 2. Additionally, the Companies will finalize contracts with the SI and PMO and work with consultants and selected vendors to develop construction schedules, all with the goal to have everything in place to start construction of the smart meter infrastructure upon approval of this Deployment Plan.

The Solution Validation Stage incorporates two activities: the build-out of the infrastructure needed to install smart meters and a testing period in which a "mini version" of the end to end smart meter solution is constructed and tested prior to full scale deployment. This stage is expected to start in late 2013 and continue through early 2017.

- *Build-Out Activities*. This period begins upon Commission approval of this Deployment Plan and will continue for approximately three years. During this period, the Companies will commence construction of the smart meter solution infrastructure, or "backbone" for the "mini system". This will involve the installation of meters, collectors, network communications, and meter data management systems for testing.

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5 Tariff provisions implementing the Companies' proposals for Early Adopters were filed with the Commission on October 31, 2012 and approved on December 21, 2012. *See* Docket Nos. R-2012-2332803; R-2012-2332776; R-2012-2332785; R-2012-2332790.

6 In the event public cellular coverage is unavailable for a requesting customer, the Companies will investigate alternative solutions on a case-by-case basis.

- *Solution Testing Activities*. As the infrastructure is built, the Companies will start to install meters in Penn Power's service territory. This territory was selected because it includes the types of challenges the SMIP Team anticipates encountering during full deployment. Approximately 5,000 meters will be installed in 2014; 15,000 in 2015; and 40,000 in 2016, so as to allow for testing of scalability and resolution of communication, functionality and installation problems encountered in a contained and controlled environment, thus minimizing costs of deployment and customer frustration. Only after all such problems are resolved will the Companies commence the final stage, Full-Scale Deployment, currently anticipated to commence in early 2017.

The Full-Scale Deployment Stage will commence upon resolution of all problems encountered during the Solution Validation Stage and will continue until all meters are installed on or before December 31, 2022. During this stage, the remainder of the smart meter infrastructure will be concurrently built in each of the Companies respective service territories, starting with the most populated areas first. All remaining smart meters will also be installed during this Stage at an anticipated average meter installation rate of 3,000 meters per day, five days per week. At this pace, the Companies expect to install approximately 98.5% of all meters between January 1, 2014 and December 31, 2019, with the remaining 1.5% of the meters being installed thereafter through December 31, 2022. The 1.5 % of the installations represent those installations that may require alternative communication solutions or difficult to reach locations such as remote hunting cabins. While the meters upon installation will be *capable* of providing all meter functionality required by Act 129 and the Commission's Implementation Order, *actual* functionality will become available upon completion of the communication network in the area, currently expected to lag installation by approximately 3 months.

1.7 Financial Implications

The Companies' financial assessment is based on a 20 year life cycle and a financial model that was designed to estimate the costs of implementing this Deployment Plan as well as the estimated potential verifiable savings that may be realized through the installation of smart meter technology.

Below is a summary of both the estimated costs and estimated potential savings by Company in nominal dollars over the 20 year life of the project:

Figure 1.2 Estimated Costs and Potential Savings
($ Millions, Nominal, 20 Yrs)

	Total PA	Met-Ed	Penelec	Penn Power	WPP
Capital Costs	$ 675,545,057	$ 183,477,974	$194,898,184	$60,835,724	$236,333,175
O&M Costs	$ 582,050,231	$ 160,654,324	$170,341,817	$45,273,136	$205,780,954
Total Costs	$ 1,257,595,288	$ 344,132,298	$365,240,001	$106,108,861	$442,114,128
Total Savings	$ 405,518,837	$ 114,946,331	$115,584,984	$33,991,482	$140,996,040

Key assumptions and calculation drivers for each of the cost and operational savings components are discussed in detail in Chapter 4.

1.8 Cost Recovery and Bill Impacts

1.8.1 Cost Recovery

Costs associated with this Deployment Plan will be recovered through existing Commission-approved SMT-C Riders. The SMT-C Riders contain SMT-C rates calculated separately for the residential, commercial, and industrial customer classes, and are expressed as a non-bypassable monthly customer charge to all metered customer accounts except for West Penn's residential customer class, which is billed on a dollar per kilowatt-hour basis. The SMT-C Riders are a reconcilable automatic adjustment clause under Section 1307 of the Pennsylvania Public Utility Code and recover capital and O&M costs and provide a return on capital investments.

Details on the cost recovery riders and other rate related issues are discussed in Chapter 5.

1.8.2 Estimated Customer Bill Impacts

Below is an estimate of monthly customer bill impacts by Company while this Deployment Plan is in effect:

Figure 1.3 Monthly Bill Impacts (Nominal)[7]

Op Co	Residential		Commercial		Industrial	
	Range	Average	Range	Average	Range	Average
MetEd	$1.04 - $4.58	$2.19	$1.12 - $5.37	$2.61	$1.11 - $7.04	$3.32
Penelec	$1.03 - $4.62	$2.25	$1.11 - $5.38	$2.63	$1.02 - $6.84	$3.26
Penn Power	$1.08 - $4.31	$2.27	$1.19 - $5.21	$2.81	$1.16 - $6.35	$3.42
West Penn Power	$1.32 - $4.91*	$2.61*	$1.60 - $5.68	$3.04	$2.39 - $7.61	$3.89

Additional details are set forth in Chapter 5.

[7] West Penn residential rates (indicated by an asterisk) are proposed on a Kwh basis to be consistent with the West Penn June 30, 2011 Commission-approved Joint Petition for Settlement.

CHAPTER 2. DEPLOYMENT PLAN DEVELOPMENT

2.1 Overview

The PA Companies, later joined by West Penn, developed the Deployment Plan during the thirty month Grace Period following Commission approval of their SMIP in June 2010. In order to address the full scope of the Deployment Plan requirements, the PA Companies, in 2010, supplemented their then-existing SMIP team by adding more FirstEnergy employees (including some from West Penn post-merger) with a variety of skill sets, and additional subject matter experts from IBM, Black & Veatch and various technology vendor representatives knowledgeable in areas involving key components and process designs of smart meter infrastructure solutions ("SMIP Team").

The SMIP Team was subdivided into nine substantive subgroups, or workstreams:

(i) Solution Framework;

(ii) Current State;

(iii) Vendor Strategy;

(iv) Technology Evaluation and Test Lab;

(v) Future State;

(vi) Network Communications;

(vii) External Communications and Consumer Awareness Strategies;

(viii) Change Management and Training; and

(ix) Program Management Office ("PMO").

Each workstream was tasked with assessing the Companies' current state of smart meter infrastructure, technology "baselines" within the Companies, and available technologies and vendors. The workstream subgroups were then tasked with developing future state requirements for an initial design for a transition to smart meter technology by the Companies.

Upon completion of this assessment and initial design work, the Companies, with assistance from IBM consultants, developed a set of RFIs to a variety of vendors, which in turn led to RFPs from a shorter list of vendors identified through the RFI process. The various technologies offered by these vendors were tested both in the Companies' test labs and in the field to ensure that each piece of equipment selected would operate properly with the other infrastructure components and provide the functionality necessary to comply with Act 129 and Commission requirements. Following visits to utilities which had implemented the different vendor technologies, the SMIP team selected the smart meter infrastructure that is described in Chapter 3.

2.2 Selection of Consultants

In order to develop their SMIP, the PA Companies implemented a competitive procurement process in 2009-2010 for experienced consultants. Black and Veatch was selected through this process and assisted with the PA Companies' development of their SMIP. Subsequently, the Companies conducted a second procurement process and selected IBM (with Black & Veatch as a sub-partner) to design and implement the work plan for the Assessment Period and to develop this Deployment Plan as part of the SMIP Team. The decision to select IBM with Black & Veatch was based on their extensive experience in planning for and implementing smart metering projects for other utilities. In addition to IBM and Black & Veatch, the SMIP Team worked with SAP America, Inc. (SAP), Itron, Inc. (Itron), eMeter Corporation (eMeter), Sensus USA Inc. (Sensus), and Landis+Gyr Technology, Inc. (Landis+Gyr) in the Solution Framework.

Following the FirstEnergy-Allegheny merger in 2011, the scope of IBM's role expanded to support the assessment, analysis and integration of West Penn's smart meter needs into the Deployment Plan and to assist in the related analyses of costs and potential savings for all four of the Companies.

2.3 Assessment of Needs

2.3.1 Background

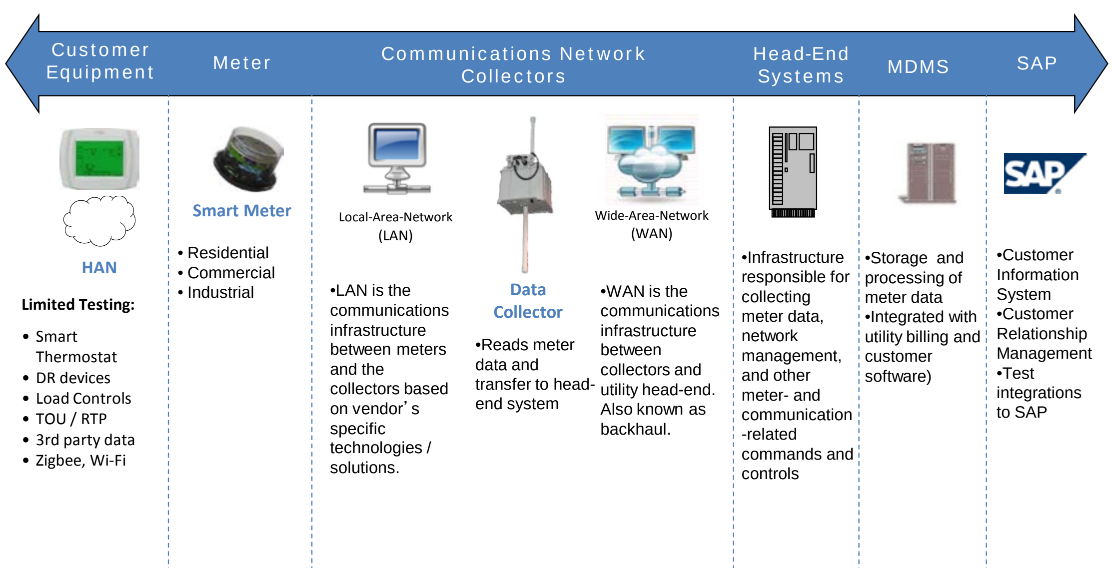
The integration of smart meters and supporting technologies is known as Advanced Metering Infrastructure ("AMI"). AMI enables bidirectional communication, records customer consumption hourly (or more frequently), and provides for transmittal of meter readings over a communication network to a central collection point and supporting commercial systems. As described in Chapter 1, the components of an AMI system typically include smart meters, a MDMS, a Head End/collection engine, and a backhaul communications network.

The technology needs assessment addressed each of these AMI components and vendors and equipment capable of supplying the functionality needed to meet the Commission's requirements. The outcome of this assessment was a solutions architecture that detailed the systems environment needed to install smart meters and the associated infrastructure. The architecture formed the basis of the vendor evaluation process and served as a key input to the financial analysis surrounding the recommended solution and this Deployment Plan.

The technology needs assessment was led by a team consisting of the Companies' IT professionals, representatives from business units and consultants from IBM. The consulting team brought specific knowledge, experience and a well-coordinated, planned approach gained from developing similar AMI solutions with other utilities across the United States and internationally. The team also defined a structured process for assessing requirements, identifying potential solutions, soliciting information from vendors, testing potential technologies in a lab and under field conditions and evaluating the costs and benefits of alternatives. In addition, both Current and Future State workshops were held, focusing on the technical implications of smart meters vis-à-vis the impacts on the Companies' business processes.

Figure 2.1 illustrates the interdependent chain of components considered in the smart meter solutions architecture, starting at the customer and ending with the Companies' billing and financial systems. Each of these components was addressed within the scope of the solutions architecture analysis and definition. Each component was also part of the end-to-end testing in both the test lab and in the field.

Figure 2.1 AMI High Level Scope Overview



2.3.2 Current State of Company Technologies

In order to evaluate the variety of possible smart meter solutions, the SMIP team undertook an extensive current state technology environment assessment focused on the Companies' existing IT applications and infrastructure that would be affected by smart metering, including metering and core applications for data gathering, processing, billing, reporting, and customer contact. The current state of both of these areas is summarized below.

Metering Environment

In Pennsylvania, the Companies serve approximately 2.0 million customers over approximately 33,000 square miles, primarily using manual meter reading along with a limited amount of interval meters. FieldNet is the Companies' system for manually reading meters. The Companies have approximately 4,000 interval meters in Pennsylvania that serve commercial and industrial ("C&I") customers.

The following table shows the breakdown of meters by operating company:

Figure 2.2 Meter Quantities and Types by Company

	Penn Power	Met-Ed	Penelec	WPP	Total
Residential	148,144	486,799	501,205	614,107	1,750,255
Commercial	20,356	64,712	82,081	92,414	259,563
Industrial	150	857	863	2,668	4,538
Public Street and Highway	86	671	860	558	2,175
Total Customers:	159,531	555,409	583,082	715,879	2,013,901
Total Meters:	168,650	552,368	584,149	709,189	2,014,356
***Total Square Miles:**	1,588	3,570	17,768	10,364	33,290
Meters/Square Mile:	106	154	33	70	61

* Total Number of Meters are higher than the Total Number of Customers since some customers have multiple meters

The service territories are unique, with diverse terrains that have varying degrees of customer density which distinguish them from other peer utilities. For example, the territories include both metropolitan and rural areas and terrains of mountains and valleys. In some instances, there are fewer than 10 meters per square mile and in other instances meters may be found underground or in block cement structures. Figure 2.3 shows the actual density distribution across the Companies' service territories:

Figure 2.3 Service Territory Definition and Meter Density Distribution

Category	Area	Meters
High ≥ 200 end points / square mile	0.4%	15.7%
Medium 101 < 200 end points / square mile	1.7%	26.5%
Low 11 < 100 end points / square mile	21.4%	48.6%
Very Low ≤ 10 end points / square mile	76.5%	9.2%
Total	100%	100%

West Penn's metering systems have been migrated to system platforms shared by the PA Companies. In accordance with its obligations under various settlements approved by the Commission, West Penn has an additional 25,000 smart meters already installed in its territory, which help it achieve its goals under its current Energy Efficiency and Conservation ("EE&C") Plan. These meters are manufactured by Itron and utilize a Smartsynch point-to-point solution, communicating data over a public cellular network. While these meters will be replaced as part of the Companies' smart meter solution, significant benefits accrued to the development of the Companies' selected solution as a result of West Penn's early smart meter deployment.

Core Applications

The Companies' core application processes that will be impacted by AMI are executed and managed by multiple systems and applications that fall into these major groups:

- Billing, Revenue, and Settlement Operations-Related Systems – These systems perform billing functions and provide data to various billing peripheral applications. The Companies utilize the SAP solution for billing and customer management. In addition, these systems provide settlement information to reconcile load and generation reporting to PJM, the Regional Transmission Organization ("RTO") for the Companies.

- Meter Data Collection Systems – These applications are tasked with collecting customer meter readings used for billing.

- Meter Management Systems – These applications primarily manage meter asset information including meter record creation, meter installation/removal, meter equipment specifications, and meter inventory tracking.

- Customer Contact Systems – These applications provide multiple contact points for customer communications and notifications. Applications include a web portal for C&I customers to view their interval data. Web presentment capabilities also include access to account and billing information, as well as a series of self-service transactions such as requests to move-in/move-out, upgrade service, report outages, and pay bills. Other capabilities include enrollment in budget billing and paperless billing, the ability to submit meter reads, and online access to education and safety information, the Companies' consumer product store, and a home energy analyzer allowing customers to receive personal energy profile information with graphs and downloadable data.

2.3.3 Assessment of Smart Meter and AMI Technologies

Smart metering and AMI technologies continue to evolve rapidly as utilities gain more experience, new requirements are identified, and technologies are tested under production conditions and improved upon. An unbiased review of the AMI/smart metering industry would best describe the industry as in its infancy, in flux and emerging. Of concern to the Companies is the constantly changing landscape of smart metering and AMI vendors. Financial stability, ability to meet production requirements, mergers and acquisitions, and intellectual property disputes were among the many types of vendor risks the Companies had to consider. These, as well as the following technical and vendor specific considerations, were factored into the AMI solution evaluation process.

Technical considerations include:

- Determining the correct technologies for the communications network best suited for a utility's service area topography and population
- Ensuring proper end-to-end bandwidth throughout the network, from HAN to back office
- Mitigating future risks by planning ahead to allow for flexibility
- Version management across multiple vendors and technologies, meter forms, program releases, Head Ends, MDMS, and corporate systems (e.g., SAP)
- Ensuring there is a prudent and defensible amount of testing for every version, release, and component
- Adhering to industry standards, including information security

Vendor-specific considerations include ensuring:

- Vendor’s component functionality meets or exceeds identified business requirements
- Proper scale and performance testing by Vendor is conducted
- Vendor roadmaps align with the Companies’ implementation plans
- Adequate management of technology upgrades
- Meter accuracy
- Deployment history/experience

The recommendations included in this Deployment Plan are dependent upon numerous vendors that will supply components (hardware, software, communications, services, system integration, and maintenance) of the solution. The vendor evaluation and procurement process, therefore, was crucial in selecting the right combination of vendors to meet the Companies’ technical, functional, and business specifications. These activities drove the vendor and technology recommendations, based on validation in the test lab and field assessment.

2.3.3.1 Approach

The Companies have an extensive vendor selection process, managed and coordinated by FirstEnergy’s procurement organization. In order to complement that process for this project, the Companies teamed with consultants from IBM who leveraged their experience with a number of AMI vendors and other utilities involved in various stages of smart meter deployment.

Through joint working sessions, an approach specific to AMI solutions was defined to methodically and deliberately move through the technology assessment, vendor evaluation and selection process. This approach ensured that key stakeholders within the Companies’ business units were engaged in the selection process. The methodology and framework also ensured a disciplined, fair, and consistent vendor RFP and evaluation process that was fully documented.

The method undertaken for technology selection emphasized both tactical and strategic objectives and included:

- Ensuring that the ultimate AMI system meets tactical, strategic, and regulatory requirements

- Mitigating risk by allowing time for thorough testing and more informed decisions
- Ensuring on-going commercial flexibility and leverage until the full range of options is thoroughly explored, understood and evaluated
- Staging decisions so that they are made on a timely basis to meet overall project objectives, yet permitting additional critical information to flow into the decision process on the most critical decisions

The vendor evaluation process used an iterative process to evaluate and refine vendor options. This approach included the following components:

- Development of business, functional and technical requirements
- Identification of vendors and gathering data through an RFI process
- Assembly of a vendor short list
- Test lab and field assessment of technologies
- Execution of an RFP

Results and deliverables produced through this process were passed through gating reviews that involved detailed review, revision and approval by members of the SMIP Team.

2.3.3.2 Vendor Short List

The purpose of the Vendor Short List was to provide an assessment of the leading AMI solution vendors and meter manufacturers based on the experience of IBM and the knowledge of subject matter experts within the Companies. This team developed a Vendor Short List to determine those vendors that offered the most viable solutions for the Companies based on key priorities of this Deployment Plan. The priorities included:

- A range of technologies that could be considered for deployment as part of the Companies' smart meter solution
- Compatibility of vendor products with the Companies' overall solution architecture (including the ability to integrate with SAP)
- Commercial flexibility to use multiple vendors to support the Companies' smart meter program objectives

The Vendor Short List evaluated vendors for five components of the smart meter solution:

- Metering

- Head End
- Backhaul
- MDMS
- Meter Deployment

The AMI solution vendors and meter manufacturers were assessed using a comprehensive set of considerations, including:

- Functionality
- Technical features
- Network/communications
- Environment
- Security
- Alignment with the Companies' solution architecture
- Corporate stability and market presence
- Pricing

Business, functional and technical requirements were developed based on the results of a high-level requirements workshop with the Companies' leadership and IBM, followed by a series of requirement gathering workshops with the Companies' managers and subject matter experts. In addition to the internal work, IBM also reached out to other utilities across the country involved in AMI projects in order to determine if there were any evolving issues identified from their projects/experiences.

The requirements identified formed the basis for the development of the evaluation matrix and weighting criteria and were used in the development of the RFP. The following groups of requirements and specifications were defined:

- Mandatory smart meter requirements of Act 129:

    1. The ability to provide bidirectional data communications;

    2. The ability to record usage data on at least an hourly basis once per day;

    3. The ability to provide customers with direct access to and use of price and consumption information;

4. The ability to provide customers with information on their hourly consumption;

5. The ability to enable Time-Of-Use ("TOU") rates and Real-Time Pricing ("RTP") program; and

6. The ability to support the automatic control of the customer's electric consumption.

- Additional functionality identified by the Commission in its Implementation Order for consideration, subject to deployment requirements:

  1. The ability to remotely disconnect and reconnect;

  2. The ability to provide 15 minute or shorter interval data to customers, EGSs, third parties and a regional transmission organization ("RTO") on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO;

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

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

  5. The ability to upgrade these minimum capabilities as technology advances and becomes economically feasible;

  6. The ability to monitor voltage at each meter and report data in a manner that allows an electric utility to react to the information;

  7. The ability to remotely reprogram the meter;

  8. The ability to communicate outages and restorations; and

  9. The ability to support net metering of customer generators.

- Additional suggested business requirements developed across different areas of the Companies (including Meter Reading, Meter Services, Revenue Operations, Billing, Rates, Customer Account Services, Customer Contact Center, T&D Planning, etc.) to support the above requirements. These requirements included:

1. Cyber security standards, internal security controls, physical environmental protections, etc.;

2. Additional functional specifications such as daily delivery of data, on-demand reads, outage flags, tamper flags, etc.;

3. Additional system specifications such as communications infrastructure, components specifications, storage, system accuracy, performance, etc.;

4. Implementation service requirements to support meter installation, configuration, reprogramming, etc.; and

5. Maintenance and support requirements, including testing and disaster recovery.

The Companies also identified the following requirements deemed essential for successful implementation:

- The functionality to integrate data from the meter to the Companies' SAP systems through the back-end system must be supported

- Multiple communication types (Head End to meter) over public network must be supported

- Multiple meter vendors must be supported by the AMI network

- The network must be robust in both high and low density environments

Using these requirements as the starting point, a business, functional and technical assessment was conducted to identify the requirements and specifications for smart meters.

2.3.3.3 The RFI Process

The SMIP Team issued its smart meter RFI in 2010, followed by RFPs in 2011. The RFI helped to establish/confirm information about the various vendors; provided more guidance during the development of the RFPs; provided input into the field assessment; and provided indicative pricing for use in the financial assessment of the smart meter solution and this Deployment Plan.

For the RFI, the business/technical requirements were developed with the understanding that the different product vendors would provide answers for the relevant deployment activity (i.e., meter vendors answer deployment/installation questions; Head End and MDMS vendors provide answers regarding software implementation). Requirements were also developed with the intent of supporting one RFI document, with vendors being given the option to propose one or more components in their response (e.g., meter, Head End, and/or MDMS).

The scope of the RFI was limited to the meters, Head End, and MDMS. RFI responses were evaluated using the following criteria:

- Act 129 requirements
- Commission Implementation Order requirements
- Extent of multiple communication offerings
- Robustness of communications network in all types of terrain environments
- Meter form support
- AMI solution security/privacy
- Solution maturity
- Solution scalability and performance
- Solution reliability
- Meter reliability
- Interoperability and open standards/compliance
- Corporate and financial stability
- Other North American deployments
- Solution pricing
- Support

MDMS systems were also required to be SAP-certified for integration with the Companies' SAP system used for billing and customer management.

Once RFI responses were received in Q1 2011, the team used a detailed evaluation plan and scoring template to assess results. RFI features were divided into two parts: those with objective responses and those with subjective responses. Preliminary testing of various vendors' technologies took place in the Companies' test labs. This was done to ensure that the various technologies performed as described by the vendors.

As a result of the RFI, a number of refinements and clarifications were made to the RFP before it was issued to vendors. The RFI also helped eliminate several vendors whose solutions did not align with the Companies' requirements or pass preliminary testing.

2.3.3.4 The RFP Process

The development of the RFPs occurred during Q2 & Q3 of 2011. Generally a format similar to that used for the RFI was employed to ensure that a high percentage of the content would be transferable. Although similar, there were several distinct differences between the RFI and the RFP processes, including:

- The single comprehensive RFI was broken out into five separate RFPs (adding backhaul deployment)
- Restated requirements (for clarity)
- Responses to clarifying questions raised during the RFI process were incorporated
- Performance requirements were incorporated
- Vendors were solicited for specific components, rather than allowing vendors to pick and choose on which of the components they desired to bid

2.3.3.4.1 RFP Requirements

Each of the five RFPs (smart meters, Head end system, MDMS, backhaul and meter deployment) required that the following information be provided:

- Concise description of overall experience/capabilities
- Detailed description of specific, by topic, experience/capabilities
- Identification of instances where subcontractors were used/leveraged to achieve success
- List of clients where similar efforts and/or solutions were performed
- A description of each solution, including the duration of each effort
- Examples of actual deliverables produced (redacted where required)
- Identification of responsible resources actively engaged in solution/deliverable
- Understanding of PA Act 129 objectives, deliverables and requirements
- A summary of solutions with timelines, key milestones, resource requirements, costs-to-achieve, used successfully at an EDC
- Experiences with electric utilities in North America with over 1,000,000 customers
- Vendor views on potential savings, reliability improvements, efficiency improvements and consumer benefits

- Regulatory experiences in PA or other jurisdictions
- Relevant experience with SAP systems and/or interfaces
- Documentation materials

Finally, each component RFP had specific selection criteria for vendors to meet as listed below.

Smart Meter RFP

The smart meter RFP sought to gain information about a vendor, its product(s) and its ability to demonstrate experience in the installation and implementation of smart meter technology. The specific criteria for the smart meter vendor were:

- Demonstrated understanding of remote service switches, service limiting, and pre-paid technologies including the management of regulatory challenges in implementation
- Demonstrated knowledge of theft and tampering strategies and solutions
- Demonstrated strategies for low-income and high-risk customers
- Knowledge and experience regarding security and privacy issues related to meter data
- Knowledge of smart meter rules/standards (NIST, IEEE, ANSI, NERC, CIP)
- Knowledge of enabling components (ZigBee, remote service switch)
- Knowledge of meter reading with automation
- Experience with smart meter supporting communications infrastructure assessment and analysis
- Knowledge of smart meter system operating life
- Knowledge of linkage between network and meters
- Meter manufacturer industry knowledge

Head End System RFP

The Companies define a Head End to include the Head End unit and the wireless communications (LAN) from and to the meter, excluding the backhaul. Below is a list of information that this RFP sought:

- Demonstrated understanding of remote service switch, service limiting, and pre-paid technologies including the management of regulatory challenges in implementation

- Demonstrated knowledge of theft and tampering strategies and solutions
- Demonstrated strategies for low-income and high-risk customers
- Knowledge and experience regarding security and privacy issues related to meter data
- Knowledge of smart meter rules/standards (NIST, IEEE)
- Knowledge of enabling components (ZigBee, remote service switch)
- Experience with smart meter supporting communications infrastructure assessment and analysis
- Knowledge of linkage between network and meters
- Experience with various communication components available today and how they natively work with meters
- Meter manufacturer industry knowledge

Meter Data Management RFP

The MDMS is designed to manage and retain the volumes of information that will be gathered from meters. In addition to the general requirements, the MDMS RFP inquired into the following:

- Knowledge of business unit implementation impacts
- In-depth knowledge of Itron MV-90 system, including system interface for measuring and recording customer demand, load and kWh usage, interval metering relative strengths regarding infrastructure
- Criteria / metrics for vendor's system performance
- Knowledge of data management and reporting practices and solutions
- Experience with Energy Efficiency ("EE") / Demand Response ("DR") programs based on customer class
- Assessing demand-side management impacts on PA smart meter plan
- DR savings metrics and measures
- Understanding of how EE/DR ties back to Act 129 filing
- Vendor deliverables acceptance sign-off / Criteria

Backhaul RFP

The Companies define backhaul as all service between the AMI LAN takeout points and the Head End. Below is the information that the backhaul RFP asked for:

- Experience with smart meter system communication backhaul
- Experience with public networks
- Experience with communication network challenges
- Experience deploying on commercial and private networks
- Experience on sonnet, routing switching, IPv4 versus 6
- Experience with message modeling and traffic on public and private networks
- Overall understanding of network performance
- Experience with network management and security
- Knowledge of network requirements and network capacity
- Experience with distribution automation communications

Deployment RFP

In addition to the above criteria, the Deployment RFP also included:

- Field experience in deployment and implementation and workforce management systems
- Meter field services technician work in scheduling and planning
- Customer requests, service orders and exceptions management

2.3.3.4.2 RFP Evaluation and Assessment

Upon receipt of the responses to the RFPs, each response underwent the following process:

- Initial Evaluation
- Objective evaluation
- Subjective evaluation
- Oral presentation by vendors

This process resulted in the recommended solution set forth in Chapter 3.

Initial Evaluation

Based upon the results of the RFIs, the preliminary testing and the RFPs, three Head End vendors were selected for further consideration; two for meters; eight for backhaul; two for MDMS; and four for meter deployment.

Some vendors who received an invitation chose not to respond. In the case of the MDMS RFP, this immediately led to the final two vendors. However, the entire RFP evaluation process was still undertaken so that the evaluators had an objective analysis of the solution being offered.

Objective and Subjective Evaluation

The objective evaluation consisted of compiling the responses received from the vendors and ensuring that their proposals were relevant, met the functionality needs of the Companies' intended AMI system, and provided answers to clarifying questions. The subjective evaluation consisted of eight to twelve people (depending on component) reading the vendor responses.

Oral Presentations

The oral presentations were designed to provide the evaluation team with an opportunity to seek further clarification on responses to requirements and clarifying questions, validate and confirm the short list, and get any updates on pricing that might be available.

Once the evaluation process was completed, the SMIP Team selected the technologies that met the business, technical and functional requirements and commenced testing in an effort to determine if in fact the various technology components actually performed as described by the various vendors.

2.3.3.5 Lab and Field Testing Process

Each major component was tested in both a test lab and in the field, with the results incorporated into the overall vendor/technology evaluations. The smart meter test lab was designed to provide a controlled "under the roof" environment to test smart meter technologies and related supporting infrastructure and perform vendor evaluation for smart meter products as input to selecting technologies for the field assessment. The test lab environment was built to house multiple meter forms from several meter vendors, as well as the smart metering solution including Head End systems and MDMS systems. Integration to SAP occurred in the test lab environment. The end-state production environment was mirrored as closely as possible, taking into account cost and time.

The Reading, Pennsylvania test lab was set up in Q4 2010 with two MDMS systems, three Head End systems and primary and secondary meters. As a result of the merger with Allegheny, the SMIP Team developed a test lab at West Penn's facilities in Connellsville, Pennsylvania. Approximately one hundred meters were tested in each of the labs.

Lab Testing

Figure 2.4 shows the types of testing that were performed in the test labs:

Figure 2.4 Types of Testing

Testing type	**Description**
Smart Meter Component Testing	Verified that meter, head-end, MDMS & SAP components met the Companies' requirements and satisfied usability, compatibility with other components, communication, and reliability criteria.
Functional Testing	Verified that the integrated smart meter system supported the necessary functionality as defined in the Companies' test requirements.
Integration Testing	Verified that the integration between applications and systems functioned correctly.
Communication Testing	Verified that all components communicated through the network from the meter to head-end in both directions.
Security Testing	Verified that the application provided an adequate level of protection for confidential information and data belonging to other systems.
Error Handling Testing	Verified that the system properly detected and responded to exception conditions. The completeness of error handling determines the usability of a system and ensures that incorrect transactions and data are properly handled.

Test Activities Matrix/Test Phases

Figure 2.5 illustrates the testing activities within each phase. Each stage represents a known level of physical integration and quality. Even though the test lab is shown as a first step, it is expected that some test scenarios (e.g. component, network testing and verification of environments) will continue throughout the entire test life cycle and beyond. The testing activities executed include:

Figure 2.5 Test Activities Mapping to Test Phases

TYPE OF TEST	Test Lab Initial Test	Field Preparation	Test Lab "Business Process" Testing	Field Test	Ongoing Testing
Component Testing	■			■	
Network Testing	■			■	
Verify environments	■	■		■	
Integration		■	■	■	
Deployment verification	■			■	
Execute test scripts	■	■	■	■	■
Record results	■	■	■	■	■
Document defects	■	■	■	■	■
Regression	■	■	■	■	■
Reporting	■	■	■	■	■

Tests were prioritized into one of three ratings to further assist entry/exit activities. The three ratings are as follows:

- HIGH – These are "must pass" tests and are absolutely critical to the success of the smart meter implementation project.
- MEDIUM – These tests are run once high priority tests have been completed and passed.
- LOW – These tests are considered optional or "nice to have" and were conducted after all high/medium tests have been completed, should time permit.

Risk Assessment and Contingencies

The following risk assessment and contingency procedures were driven by the technical requirements of the solution and business functions related specifically to testing. Risks were prioritized into one of three classes to further assist their assessment and mitigation. The three classes were:

- HIGH – execution of the mitigation unlikely at present time, increasing probability that risk will occur and result in stated impact to Lab and Field Test

- MEDIUM – execution of mitigation not confirmed, though feasible at present time. Risk considered moderate until mitigation in place
- LOW – unlikely event will occur or workarounds currently in place, and therefore poses minimal risk

Test Lab Business Process Test Criteria Requirements

The following subsystems were tested during the Business Process Testing Phase:

- SAP – MDMS subsystem
- AMI network subsystem
- Smart meter infrastructure subsystem

Smart meter technology testing was executed by subsystem to reduce the complexity of the testing process and to provide a baseline of solution components that passed a specific set of tests. The testing in the lab was executed to validate the business functionality of the integration touch points between the meter to Head End, Head End to MDMS and MDMS to SAP, and overall end-to-end business processes in the smart meter integration chain.

The following functional categories were tested in the Business Process Test Phase:

- Meter installation & registration
- Meter reading
- Billing
- Critical alarms and events
- Remote service switch
- Security
- Outage detection (including security)
- Other business processes

At the conclusion of the test lab business process testing, vendors and technologies were identified to participate in the field assessment.

Field Tests

The smart meter field assessment added an additional dimension to testing and began to further explore and validate the network and communications infrastructure. The investigation and assessment had to occur in actual field conditions that resembled typical operating conditions for the Companies' s customers. The field assessment afforded the Companies the opportunity to test the network under conditions of increased distance, data demands and topographical conditions beyond the test lab.

Field assessment preparation work began in Q4 2010 with actual testing beginning in Q2 2011. The field trial focused on testing the throughput and coverage of the network communications solutions(s) and initially included installing meters in the Fox Gap and York/Pleasureville, Pennsylvania areas. Both of these locations are within Met-Ed's service territory. Met-Ed was chosen as the test region due to its proximity to the test lab in Reading.

Participation in the initial trial was voluntary, and the Companies selected approximately 350 customers who agreed to participate. The initial trial helped the Companies understand firsthand how smart metering will impact customers, and what the Companies can do to improve the customer experience, including additional communications to consumers and "best practices" for addressing resolution of technical issues.

In 2012, the Companies also conducted lab and field testing in of enhanced functionality offered by an Itron/Cisco solution. This test involved approximately an additional 350 meters and took place in Connellsville, Pennsylvania, located in West Penn's service territory.

Field Assessment

The field assessment vendor scorecard provided a process to capture field assessment test results. The vendor solution was scored based on test results, defects, issues and risks identified during the testing in order to validate that the solution in fact met all of the business requirements as specified by the Companies.

Using the same methodology that was employed in the test lab, the team identified specific criteria applicable to the Field Assessment Test Phase and developed the vendor scorecard to compare vendors against each other. Vendor scoring was performed on both quantitative and qualitative criteria and took into account the resolutions of any open issues from the field assessment execution

CHAPTER 3. SMART METER SOLUTION AND DEPLOYMENT STRATEGY

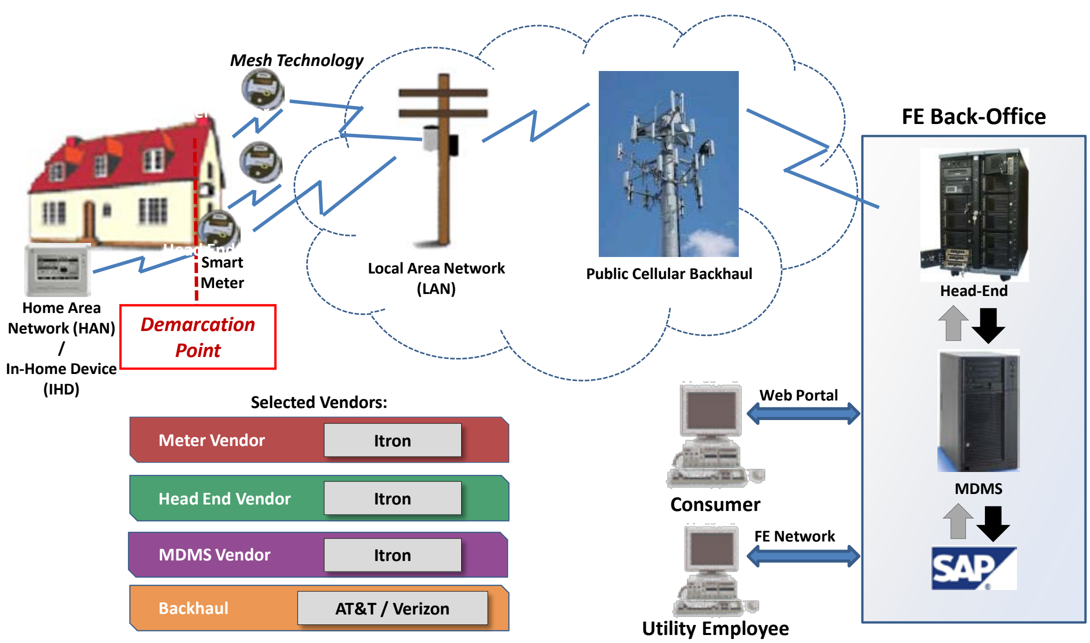
3.1 Overview

This chapter presents recommendations for the smart meter technology solution, the vendors to provide that solution, and the build-out/meter deployment/meter functionality schedules.

As discussed in Chapter 2, the recommended architecture and infrastructure solution is based upon an extensive technology needs assessment that addressed both the "current state" of each of the Companies and the vendors and equipment capable of supplying the functionality needed to meet Commission requirements. The outcome of this assessment is a technological solution that details the systems environment needed to implement smart meters and the identification of the vendors who can provide the key solution components to deliver all of the functionality specified in Act 129 and the Implementation Order.

The following chart provides a graphical representation of the smart meter solution, which is detailed in Section 3.2 below.

Figure 3.1 PA Companies Smart Meter Solution



The Companies are recommending a phased deployment strategy that anticipates three distinct stages: (i) the Post Grace Period ("PGP") Stage; (ii) the Solution Validation Stage; and (iii) the Full-Scale Deployment Stage. Under this strategy, the Companies expect to install approximately 98.5% of all smart meters between January 1, 2014 and December 31, 2019 ("Deployment Period"), with the remaining 1.5% of the meters being installed thereafter through December 31, 2022. In order to accomplish this, an average of approximately 3,000 meters per day, five days per week, will be deployed starting in 2017. And while the meters being installed will have the capability to provide the functionality required by Act 129 and requested by the Commission, the actual functionality of the smart meter will not be available until the communication network is constructed in the area. It is currently anticipated that this will lag installation by approximately three months. The entire deployment strategy is described in detail in Section 3.3.

3.2 Smart Meter Vendor, Functionality and Solution Architecture

3.2.1 Meter Vendor

Itron is the recommended meter vendor based on the vendor selection process described in Chapter 2. The Itron smart meters selected by the Companies are capable of providing all of the functionality required by Act 129 and the Commission's Implementation Order as the Companies' network is deployed as described in Section 3.3, including the following specific features.

Remote Service Switches

The smart meters will be able to remotely connect and disconnect customers. The Companies intend to implement the reconnect function and will implement the remote disconnect function only upon request by the customer and in compliance with Chapter 56 of the Commission's regulations.

Read Intervals

Meter reading will be an automated, scheduled process through which meters read, record, and send interval meter readings and other data on a regular frequency. Initially, interval meter readings will be taken at hourly intervals, while register readings which, in essence, accumulate the interval reads, will be done on a daily basis. While the meters are capable of obtaining 15-minute (or shorter) interval data, this functionality will not be made available upon installation because significant issues, such as how the storage of such data should be paid for and by whom, have not been resolved. Because these issues are common among all of the Pennsylvania EDCs, the Companies will await further guidance from the Commission before pursuing the implementation of shorter interval reads.

Meter Storage, Open Standards, Upgradability and Remote Programming Capability

The smart meters are capable of storing data and have open standards consistent with nationally recognized standards. The meters are also upgradable and reprogrammable.

Voltage Monitoring/Outages and Restoration

The smart meters can measure and record voltage information at the meter, and transmit it to the Head End. The proposed architecture allows for the creation of reports that can be utilized by the Companies, in conjunction with existing capabilities, to analyze and assess the overall health of power distribution to the meter. Voltage monitoring alone, however, does not provide the level of accuracy and insight at the transmission and distribution level needed to support predictive, proactive outage management prevention and resolution. Rather, this new functionality will supply additional information to support the existing outage management capabilities. In order to automate outage reporting and restoration, the smart meter infrastructure must be in place and then interfaced with the Companies' current outage management system. Therefore, this functionality will not be available at the time of installation. Given that full-scale deployment will not begin until 2017, the Companies have not prepared a cost benefit analysis of this functionality for purposes of this Plan, but will be doing so during the later stages of the Deployment Schedule.

Net Metering

The smart meters will support the ability to provide net metering. Itron meters support energy received and delivered as well as profile loads where customers have existing generation sources such as wind and solar.

3.2.1.1 Solution Architecture

In order to provide the requisite functionality, an entire network of hardware and communication systems must be integrated. The main components of this network includes (i) the Smart Meter; (ii) the Head End; (iii) the Meter Data Management System ("MDMS"); (iv) the Companies' Legacy systems; (v) a Communication Network; and, while not part of the Companies' network, (vi) the customer's HAN. Components (ii) through (vi) and recommended vendors, where applicable, are discussed below.

Head End

In the proposed architecture, the Head End serves primarily as the gateway for all communications to the meters and other connected devices, such as collectors. It collects unvalidated meter data (e.g. consumption, interval, event data, power status, etc) and transmits it to the MDMS. Based on the RFP responses and test results, the Companies have selected Itron as the Head End vendor.

MDMS

Itron was also selected as the MDMS vendor. The MDMS will receive, store, validate, estimate, and aggregate data from the Head End, and processes meter data in three steps: Validation, Estimation, and Editing ("VEE"). The MDMS serves as the primary repository of all measurement, status, and event data collected by the smart meters. The MDMS is also the gateway for communication with the smart meters supporting data requests, commands, and alert messages from/to the Companies' other information systems, such as Customer Care & Billing, Work & Asset Management, and Work Force Management.

In the validation step, the MDMS reviews the unvalidated data from the smart meters and compares it to expected values. Meter reads that fall outside the high/low range or exceed the variance of expected values, fail validation and are flagged. Subsequently, invalid, incomplete, or missing reads are estimated along with reads that fail validation. The VEE process ensures that the Companies have validated smart meter data available for customer billing and operations.

Additional functions of the MDMS include the processing of remote service orders, status data, and event data on significant changes in the state of system or network resource, network application, data flow or security.

3.2.2 Other Existing Legacy Systems

As a result of the additional smart meter functionality, the Companies anticipate the need to upgrade certain legacy systems:

Operational Data Store ("ODS")

The ODS is the repository for interval data. The current ODS will need to be upgraded to support the proposed smart meter solution and future smart meter technology developments.

SAP

The successful integration of the smart meter components, the MDMS, and the Companies' core applications is crucial to the success of the SMIP Project. SAP will remain in place as the Companies' primary system for customer and billing information, but it will be upgraded to support the proposed smart meter solution and future smart meter technology developments.

3.2.3 Communications Network

Network communications is not a single solution, but consists of a series of components that enable meters to communicate with collectors and a backhaul, in which collectors communicate with the Head End. Based on the results of the RFP process, the Companies propose to construct a smart meter network as shown in more detail in Figure 3.1.

In the proposed network, Itron meters will use radio frequency (for which a license is not required) to dynamically discover each other and form a mesh network that connect them to communication devices known as collectors, creating a LAN.[8]

The LAN connection between an individual meter and the collector in the Companies' proposed architecture will use a proprietary communications protocol that is unique to the meter vendor. The collector will then link to a Wide Area Network ("WAN") which uses a standard protocol for "backhaul" services to connect the meter to the Head End.

During the design and RFP processes, the risks and rewards of public versus private backhaul WAN network options were considered. Generally, the use of public cellular networks is preferable for the following reasons:

- Public carrier networks already exist and are available for immediate implementation to facilitate deployment timelines.

[8] The diverse geographic and urban density nature of the Companies' service territories makes it unlikely that a single meter network vendor technology will be capable of servicing 100% of the smart meters, and a small population of meters will require alternative solutions. The Companies have determined that less than 5% of customers across the Companies are located in areas where RF meters may not be able to form an RF mesh or join a neighboring mesh due to the distance from the nearest meter, terrain, subterranean location, etc. ("RF Challenged" meters). In such cases, the Companies will utilize a point-to-point ("PTP") solution, e.g., cellular communication. In some cases where the location is not RF Challenged, a PTP solution might also be utilized if it is considered more cost-effective than building an RF mesh in the local area.

- The Companies have ongoing relationships with public carriers, which are large, established companies.
- The three primary public carriers (Verizon, AT&T and Sprint) participate in industry standards organizations to ensure that their network supports directives from NERC, NIST, etc.

In comparison, private network options carry greater risk:

- The construction of a private network would challenge the Companies' ability to achieve timely deployment.
- The Companies would have to invest significant resources for the private network in order to comply with international standards.
- Private carriers are smaller companies, introducing additional risk.

As a result of this consideration and the RFP responses, the Companies concluded that the public carrier option is generally able to meet more of the necessary criteria for a well-developed smart metering environment that would comply with legislation and open standards. The Companies therefore propose to use a blend of AT&T and Verizon network services in their territories.

In order to address the fact that these networks include equipment outside of the Companies' physical control, network intrusion prevention systems will be inserted between internal systems (including Head Ends) and the meter network for inbound traffic monitoring. This will add an independent security control between key points in the network.

3.2.4 Home Area Network ("HAN")/Internet

The HAN is a data network contained within a user's home that is expected to communicate from the smart meter to in-home devices ("IHDs"). The purpose of the HAN will be for the enablement of direct access data to the customer's premise. IHDs may include in-home displays, smart thermostats, power switches, and other load control devices. While the smart meters will have the capability of supporting data transmission to and from these IHDs, the functionality is only available should the customer elect to purchase the devices. As explained in Chapter 2, the Companies will not be providing IHDs or HAN technologies to customers, instead leaving them to the competitive market. The Companies also anticipate that the HANs and IHDs will utilize the public internet for two major roles in the smart meter technical solution:

- Connecting the Companies' customers and authorized third parties to resources that are made available by the Companies, such as a customer web portal; and

- Connecting authorized third parties to the customer home networks, allowing the authorized third party to retrieve information from the customer's home network and IHDs, including the non-validated interval data from the Companies' smart meters.

3.2.5 Data Exchange Standards

By Order entered December 6, 2012 at Docket No. M-2009-2092655, the Commission established data exchange standards for current business processes. Specifically, the Commission directed that all EDCs subject to the smart meter provisions of Act 129 address standards for attaining RTP and TOU pricing capabilities, provide the EDC's current capability to provide a minimum of 12-months of historical interval usage data via electronic data interchange ("EDI"), and to incorporate meter-level interval usage data capabilities. Because the Companies' enrollment and billing system is currently programmed to accept dual billing and bill ready EDC-consolidated billing (i.e., the functions the Commission has already said present the best options for attaining RTP and TOU pricing capability), the Companies currently have the capability to provide 12-months of historical interval usage data via EDI, and the Companies currently incorporate meter-level interval usage data as directed by the Commission. Therefore, the Companies are already meeting these Commission directives.

3.3 Deployment Strategy

3.3.1 Deployment Schedule

As noted previously, the Companies are recommending a phased deployment strategy which anticipates three distinct stages: (i) the PGP Stage; (ii) the Solution Validation Stage; and (iii) the Full-Scale Deployment Stage.

The PGP Stage, which commences on January 1, 2013 and concludes with the completion of deployment, currently scheduled by December 31, 2022, addresses not only the need to provide smart meters for all new service requests received on or after January 1, 2013 ("New Construction") and for all customers requesting a smart meter prior to their scheduled installation date ("Early Adopters"), but also addresses contract negotiations, final RFPs and other pre-deployment activities.

New Construction/Early Adopters: In order to provide the functionality required by Act 129 during the PGP Stage, the Companies will implement the following process for all New Construction and Early Adopter installations:

- For new construction for which a temporary or permanent service application is received on or after January 1, 2013, the customer will be provided with the RF smart meter included in the recommended technology solution, which will eventually be able to communicate with the smart meter network infrastructure. The recovery of both the meter and related installation costs will be through the Companies' applicable standard Smart Meter Technologies Charge Rider, which is more fully discussed in Chapter 5. Customers will not be billed additional fees for the meter or other installation costs beyond that charged to all metered customers through the Smart Meter Technologies Charge Rider. During the period between smart meter installation and the build-out of the smart meter network in the area where a New Construction smart meter installation occurs, neither the communication functions of the meter nor smart meter functionality will be available and meter reads will be done manually using existing meter reading and billing procedures.

- For Early Adopters, once the customer pays the incremental costs for the meter and related installation,[9] a Point-To-Point ("PTP") smart meter that meets the basic Act 129 functionality requirements will be installed, This smart meter will communicate via a public cellular network and will provide on-line access to validated meter data within 24-48 hours and access to unvalidated meter data via a direct access interface to a device that is part of the Home Area Network.[10] Meter reads for billing purposes will continue to be done manually using existing meter reading and billing procedures until the smart meter network infrastructure becomes available at the customer's location and the PTP meter is replaced with the RF smart meter selected as part of the smart meter technological solution.

Contract Negotiation/RFPs: During the period between the filing of the Deployment Plan with the Commission and approval of the plan by the Commission (anticipated to be by September 30, 2013), the SMIP Team will negotiate final terms and conditions with the selected vendors, select a systems integrator ("SI") and project management office ("PMO") through the RFP process described in Chapter 2, finalize contracts with the SI and PMO and work with consultants and selected vendors to develop construction schedules, all with the goal to have everything in place to start construction of the smart meter infrastructure upon approval of this Deployment Plan.

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[9] Tariff provisions implementing the Companies' proposals for Early Adopters were filed with the Commission on October 31, 2012 and approved on December 21, 2012. *See* Docket Nos. R-2012-2332803; R-2012-2332776; R-2012-2332785; R-2012-2332790.

[10] In the event public cellular coverage is unavailable for a requesting customer, the Companies will investigate alternative solutions on a case-by-case basis.

The Solution Validation Stage incorporates two activities: the build out of the infrastructure needed to install smart meters and a testing period in which a “mini version” of the end to end smart meter solution is constructed and tested prior to full scale deployment. This stage is expected to start in late 2013 and continue through early 2017.

- *Build-Out Activities*. This period begins upon Commission approval of this Deployment Plan and will continue for approximately three years. During this period, the Companies will commence construction of the smart meter solution infrastructure, or “backbone” for the “mini system”. This will involve the installation of meters, collectors, network communications, and meter data management systems for testing.

- *Solution Testing Activities*. As the infrastructure is built, the Companies will start to install meters in Penn Power’s service territory. This territory was selected because it includes challenges the SMIP Team anticipates encountering during full deployment. Approximately 5,000 meters will be installed in 2014; 15,000 in 2015; and 40,000 in 2016, so as to allow for testing of scalability and resolution of communication, functionality and installation problems encountered in a contained and controlled environment, thus minimizing costs of deployment and customer frustration. Only after all such problems are resolved will the Companies commence the final stage, Full-Scale Deployment, currently anticipated to commence in early 2017.

The Full-Scale Deployment Stage will commence upon resolution of all problems encountered during the Solution Validation Stage and will continue until all meters are installed on or before December 31, 2022. During this stage, the remainder of the smart meter infrastructure will be concurrently built in each of the Companies’ respective service territories, starting with the most populated areas first. All remaining smart meters will be installed during this Stage at an anticipated average meter installation rate of 3,000 meters per day, five days per week. At this pace, the Companies expect to install approximately 98.5% of all meters by December 31, 2019, with the remaining 1.5% of the meters being installed thereafter through December 31, 2022. The 1.5 % of the installations represent those installations that may require alternative communication solutions or difficult to reach locations such as remote hunting cabins.

Figure 3.2 illustrates the anticipated implementation schedule, while Figure 3.3 illustrates the anticipated meter deployment schedule:

Figure 3.2 Smart Meter Deployment Plan Timeframe

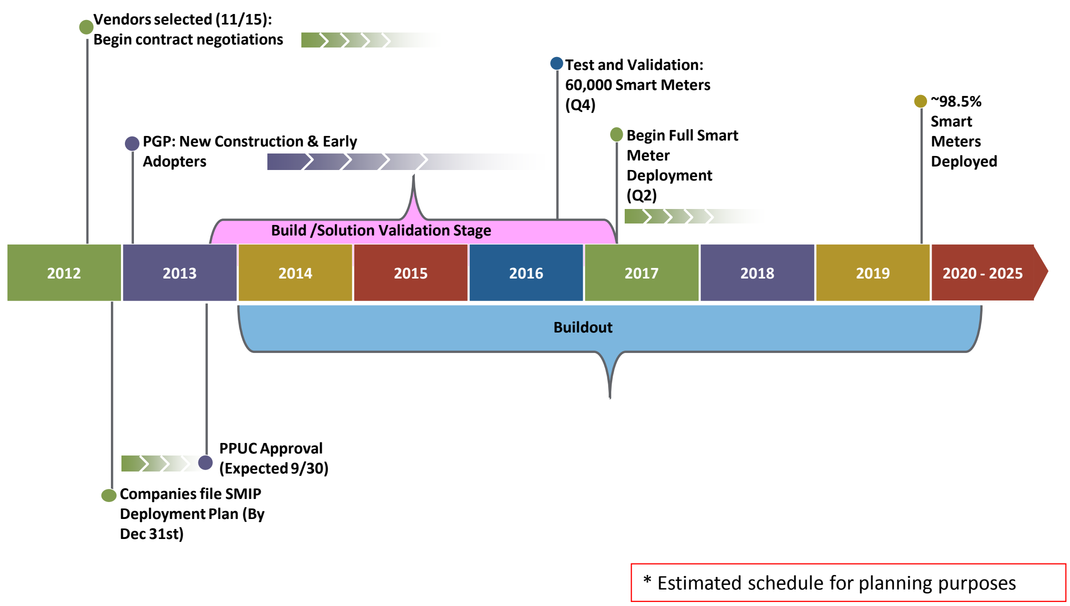
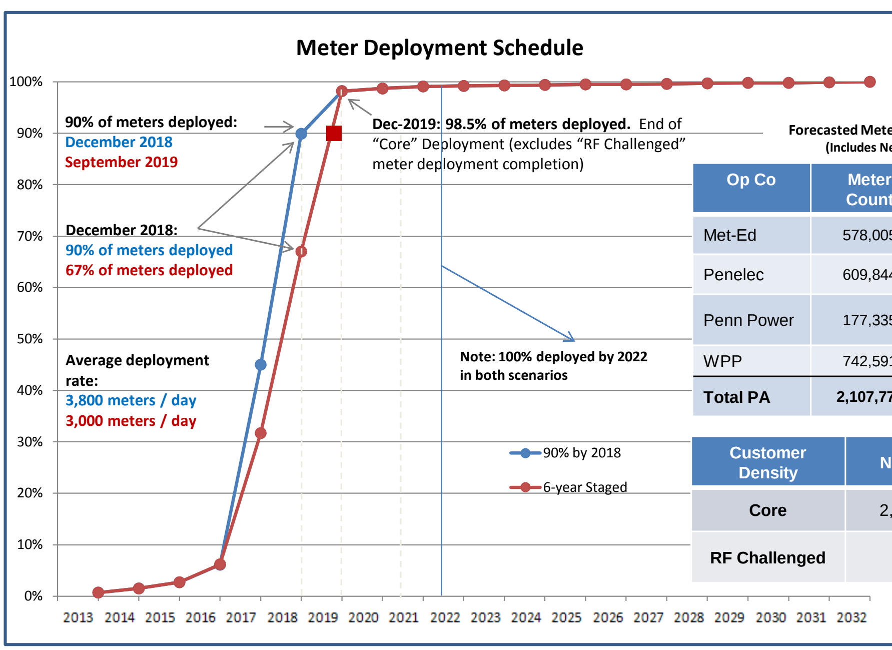


Figure 3.3 – Smart Meter Deployment Timeline – 2014 to 2019



Forecasted Meter Distribution (2032)
(Includes New Construction)

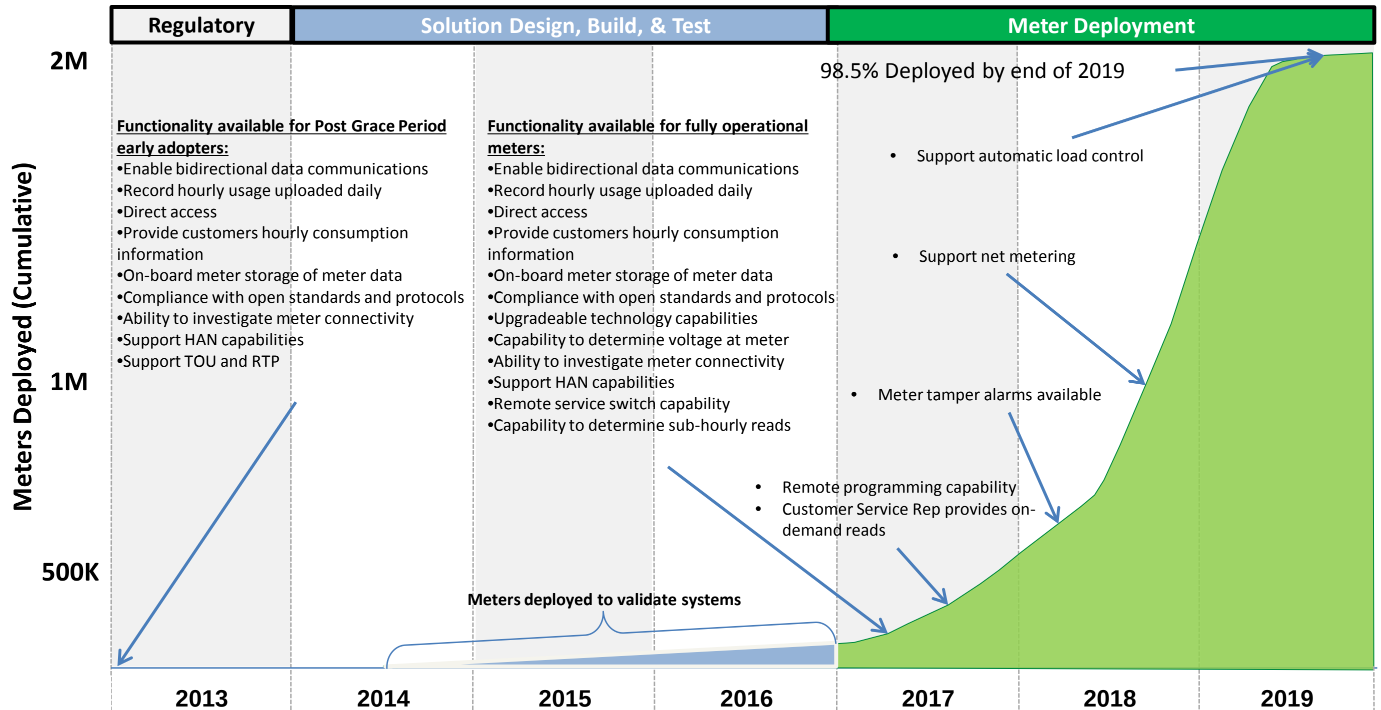
Op Co	Meter Count	Distribution of Meters
Met-Ed	578,005	28%
Penelec	609,844	29%
Penn Power	177,335	8%
WPP	742,591	35%
Total PA	**2,107,775**	**100%**

Customer Density	Number of Meters
Core	2,076,159 (98.5%)
RF Challenged	31,616 (1.5%)

3.3.2 Meter Functionality

The meters being recommended as part of the Companies' smart meter solution all comply with open standards and protocols, can be remotely programmed and can be upgraded as technology advances. They are also capable of providing all of the functionality required by Act 129 and requested by the Commission in its Implementation Order. However, not all of this functionality will be available immediately upon installation. As Figure 3.4 depicts, basic functionality required by Act 129, plus the ability to investigate meter connectivity will be available to Early Adopters upon installation of their meters during the PGP Stage. This is because a different meter will be installed with cellular communication capabilities in order to meet Act 129 requirements while the smart meter infrastructure is being built. However, the RF meters being installed as part of the smart meter mesh network solution will not have this functionality until the communication network is in place in the area. It is currently anticipated that there will be a lag of approximately three months between installation of the meters and when such functionality is available to the customer. As Figure 3.4 indicates, once this occurs, the RF meter will provide all of the functionality offered during the PGP Stage, as well as voltage monitoring capability, remote switch capability and the ability to determine sub-hourly reads remotely. The Companies currently anticipate that remote programming capability and the ability for customer service representatives to make on-demand reads will be available in late 2017, while meter tamper alarms and automated net metering support will be available sometime in 2018. Advanced automatic load control is expected to be available sometime during 2019, however, these timeframes are projections based on information as known today. Events may occur which could affect these timelines, both positively and negatively.

Figure 3.4 – Deployment Timeline with Estimated Functionality



	2013	2014	2015	2016	2017	2018	2019
PGP*	14K	28K	42K	56K	70K	84K	98K
Staged	-	5K	15K	60K	600K	1.4M	2M

Meters Deployed (Cumulative)

*Includes early adopters and new construction. Functionality for new construction will not be available until network is available in the area

3.3.3 Meter Installation

The Companies anticipate that approximately 90% of the meter installations will be standard and will be performed by both Company personnel and qualified contractors. Should the installer encounter a hazardous condition or another situation involving the meter box on the Companies' side of the meter that would normally be left to the customer to repair, the necessary repairs will be made and the installation completed at no cost to the customer. Based on discussions with other utilities, as well as the Companies' past history, the Companies estimate that up to 5% of the installations will require such additional work and have included the costs of such work in the overall plan budget.

The Companies anticipate that the remaining 10% of the installations will involve non-standard, more complex installations and will utilize internal resources for these installations. Such complexities may include installations for large C&I

customers, new construction sites, hard-to-access locations, and cases with special meter forms or electrical requirements.

CHAPTER 4. FINANCIAL ANALYSIS

In response to Act 129 and subsequent Commission Orders, the Companies initiated a detailed assessment and planning effort in preparation for the implementation of smart meters and AMI technologies. A central part of planning was the creation of a detailed SMIP financial analysis model ("Financial Model") to estimate and analyze the future costs and potential operational savings associated with this Deployment Plan. Implementation and ongoing operational costs were projected over a 20-year period.

The data underlying the financial analysis were produced through a highly interactive assessment process involving consultants from IBM and Black and Veatch, as well as professionals from impacted business units of the Companies, the FirstEnergy finance department and its rate department. The data were reviewed and updated in an iterative process throughout 2011 and 2012. The resulting analytics quantified estimated costs and potential operational savings based on information known as of August, 2012. Activities performed in the development of the Financial Model 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
- Evaluating the reasonableness of the Financial Model results based on comparisons with other utility smart meter program results
- Reviewing the Financial Model results with affected business units, the FirstEnergy financial analytics group and FirstEnergy management

Numerous scenarios were considered, with three being selected for more in-depth analysis:

- 6-year Two-stage Deployment Scenario (Recommended Deployment Schedule): Assumes 98.5 percent of all meters are installed by the end of 2019. Net cost: $852 million (nominal) and $560 million (NPV).
- 6-year Accelerated Scenario (West Penn Joint Settlement Scenario): Assumes 90 percent of all meters installed by the end of 2018, with

remainder installed by the end of 2019. Net cost: $844 million (nominal) and $562 million (NPV).

- 7-year Deployment Scenario: Assumes 98.5 percent of all meters are installed by the end of 2020. Net cost: $865 million (nominal) and $557 million (NPV).

The financial analyses included in this chapter are based on the 6-year Recommended Deployment Schedule which anticipates all smart meter infrastructure being built and 98.5 percent of all smart meters being installed between January 1, 2014 and December 31, 2019. Based on these analyses, the estimated cost of implementing this Deployment Plan over 20 years is $1.258 billion in nominal dollars, $676 million of which are for capital expenditures ("Capex") and $582 million for Operations and Maintenance ("O&M") costs. Approximately $750 million will be spent during the six year Deployment Period. The estimated total operational cost savings over the 20 year period that the Companies believe may be realized are $406 million in nominal dollars.

Below is a breakdown by Company, as generated by the Financial Model:

Figure 4.1 Estimated Costs and Potential Savings
($ Millions, Nominal, 20 Yrs)

	Total PA	Met-Ed	Penelec	Penn Power	WPP
Capital Costs	**$ 675,545,057**	**$ 183,477,974**	**$194,898,184**	**$60,835,724**	**$236,333,175**
O&M Costs	**$ 582,050,231**	**$ 160,654,324**	**$170,341,817**	**$45,273,136**	**$205,780,954**
Total Costs	**$ 1,257,595,288**	**$ 344,132,298**	**$365,240,001**	**$106,108,861**	**$442,114,128**
Total Savings	**$ 405,518,837**	**$ 114,946,331**	**$115,584,984**	**$33,991,482**	**$140,996,040**

4.1 Scope and Assumptions

The financial analysis assumes a 20 year life cycle, starting with the beginning of the Post-Grace Period Stage on January 1, 2013, and continuing through 2032. The Financial Model used to perform the financial analysis assumes that the 6 year Recommended Deployment Scenario is adopted and that deployment will commence in early 2014.

General Financial Inputs and Assumptions

- The combined state and federal FirstEnergy marginal tax rate is 41%.

- No Allowance for Funds Used During Construction ("AFUDC") is expected because the capital that will be invested in systems, network and meters will be used and useful in the year in which those costs are incurred.
- No costs are included for stranded assets, and any stranded assets will continue to be recovered in the base rates.
- Potential operational savings could be realized beginning in 2017 and lag meter deployment by one year.
- Base line costs, employee levels and other factors will be based on actual employee, cost and other metric levels as of December 31, 2013. For purposes of estimating savings, budgeted levels for 2013 were assumed.
- Equipment and outside vendor service costs were derived from pricing received through the RFP process.
- Labor related costs are fully loaded and include annual growth and human resources factors.
- Costs incurred prior to January 1, 2013 are not included in the analyses.

Book and Tax Depreciation

Each of the cost categories were assessed to determine if they were capital or O&M related costs. For Capex, the estimated book lives used for depreciation purposes were 15 year for smart meters and communications equipment, 5 years for hardware and 7 years for software. Book lives were determined based on input from external resources and internal subject matter experts while tax lives were based on IRS guidelines.

Escalation Rate

The Financial Model assumes an escalation rate of 2.56% for labor.[11] A zero percent escalation rate was assumed for equipment and material costs in recognition that material costs may increase over time while technology costs may decrease over time.

[11] Provided by the Companies Business Analytics department based on the average 12 month (Mar 2011 - Mar 2012) escalation index for the Utility industry being 2.56% from U.S. Bureau of Labor Statistics (http://data.bls.gov/cgi-bin/print.pl/news.release/eci.t09.htm)

Weighted Average Cost of Capital ("WACC")

The Financial Model assumes the following Weighted Average Cost of Capital rates:

Figure 4.2. Weighted Average Cost of Capital by Company

Penelec	Met-Ed	Penn Power	WPP
8.17%	8.68%	9.14%	11.29%

The weighted average cost of capital for Met-Ed, Penelec and Penn Power is calculated in accordance with the Commission order entered June 9, 2010 at Docket No. M-2009-2123950 approving the Joint Petition for Approval of Smart Meter Technology Procurement and Installation Plan. The weighted average cost of capital for West Penn is calculated in accordance with Commission order entered June 30, 2011 at Docket No. M-2009-2123951 approving the Amended Joint Petition for Settlement of All Issues.

Deployment Inputs and Assumptions

- No costs are included for in-home customer devices. It is assumed that this is a competitive service, the costs of which will not be paid for by the Companies.
- Meter-related repairs on the Companies' side of the meter will be necessary prior to the installation of some of the smart meters. Based on discussions with other utilities involved in smart meter projects, the Financial Model assumes such repairs will be needed for 5% of all installations at an estimated cost of $500 per installation. These costs have been capitalized as part of the meter cost.
- Based on discussions with other utilities involved in smart meter projects, the Financial Model assumes a meter failure/replacement rate of 1% through 2023 and 2% thereafter, with a manufacturer's warranty covering the first five years of each smart meter's operational life. The cost of the warranty has been capitalized as part of the meter cost.
- Radio Frequency network devices are assumed to have an annual failure rate of 1%
- The Financial Model assumes 100% full deployment, with no provision made for customer opt out.
- The Financial Model assumes that the Recommended Deployment Schedule will be followed and that all meters will be installed no later than 2022.
- 100% of the required field network devices will be deployed.

- The Companies will perform all complex meter installations which are estimated to be 10% of all installations.

Geographic Density Inputs

The Financial Model assumes four different cost profiles for the installation of meters across different geographies that were derived from pricing received through the RFP process:

Figure 4.3 Cost Profiles by Customer Class and Density

Customer Class	High Density	Medium Density	Low Density	Very Low Density
Residential	$8	$9	$11	$17
Commercial	$11	$12	$15	$24
Industrial	$33	$37	$43	$65

4.2 Overall Program Costs

The costs incurred to implement this Deployment Plan have been grouped into the following cost categories: (i) Meter and LAN; (ii) Information Technology ("IT"); (iii) Systems Integration; (iv) Network and Network Management; (v) Program Management; (vi) Business Staffing; and (vii) Communications/Change Management. Costs within each of these components were further broken down as either capital or O&M within the year(s) in which these costs would be incurred. The costs have been presented on both a nominal and net present value basis, using a 20 year analysis period. The NPV analysis has been included in order to provide a more consistent way in which to evaluate the total net costs of candidate scenarios taking into account the time value of money. The costs have been adjusted throughout this 20 year period for escalation and growth of the smart meter system based on the six year Recommended Deployment Schedule. Below is a breakdown of total costs, Capex and O&M:

Figure 4.4

Total: $1,258M

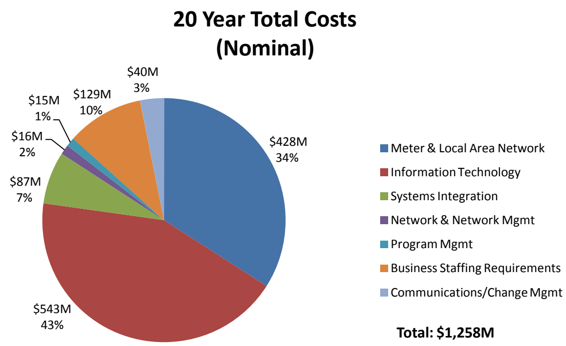


Figure 4.5

Capital Total: $676M

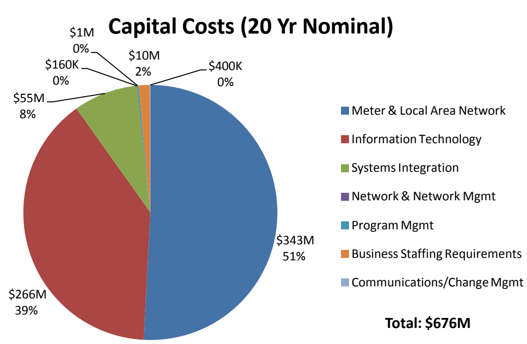
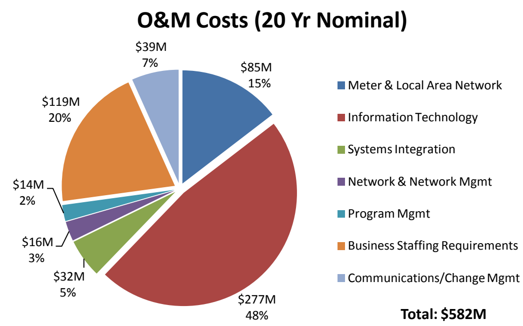


Figure 4.6

O&M Total: $582M



The cost estimates for each of the above cost categories were based on the following sources:

Figure 4.7 Cost Estimate Sources

Cost Category	Source of Cost Estimate
Meters & Local Area Network	Vendor RFP responses and internal and consulting resources based on previous experience
Network & Network Mgmt	Vendor RFP responses and IBM resources based on past experience with Oncor, CenterPoint, SCE, Sempra, Pepco, FPL and Duke
Information Technology	Vendor RFP responses and IBM/FE resources based on past experience
Systems Integration	Vendor RFP responses and IBM resources based on past experience
Business Staffing Requirements	Workshop on future state and IBM/FE resources based on past experience
Communications/Change Management	Workshop on future state and IBM/FE resources based on past experience
Program Management	Workshop on future state and IBM/FE resources based on past experience with Oncor, CenterPoint, SCE, Sempra, Pepco, FPL and Duke

4.2.1 Costs by Program Component

The estimated costs presented in this section are cumulative over the 20-year evaluation period and are presented in nominal dollars. All vendor labor during the Deployment Period has been capitalized and the Companies' labor costs are considered to be O&M.

4.2.1.1 Meter and Local Area Network

Total Estimated Cost: $428 million (34% of total project costs).

Meters (Capex): $320 million

Meters (O&M): $58 million

LAN (Capital): $23 million

LAN (O&M): $27 million

Approximately $344 million will be spent during the Deployment Period. The meter Capex costs include a 60 month warranty, initial installation costs, and shipping and handling. Meter O&M is predominantly for the labor needed over 20 years to replace failed meters. The local area network Capex costs are for collectors and repeaters, as well as installation and testing costs. All of these cost estimates were derived from the vendor pricing received through the RFP process.

4.2.1.2 Network and Network Management

Total Estimated Cost: $16 million (1% of total project costs).

Public Backhaul (Capex): $.2 million

Public Backhaul (O&M): $ 16 million

Approximately $4.3 million is expected to be spent during the Deployment Period. Capex costs for the public backhaul represent a one-time installation and set-up fee plus a refresh cost every ten years. The O&M costs include 20 years of annual service fees. All of these cost estimates were derived from the vendor pricing received through the RFP process.

4.2.1.3 Information Technology

Total Estimated Costs: $543 million (43% of total project costs).

Infrastructure (Capex): $192 million

Infrastructure (O&M) costs: $37 million

Software Applications (Capex): $20 million

Software Applications (O&M): $87 million

Resources (Capex): $53 million

Resources (O&M): $154 million

Approximately $225 million is expected to be spent during the Deployment Period. Infrastructure Capex costs are for the various components, such as MDUS, ODS, and Head End, that comprise the smart meter infrastructure. Vendor costs to install infrastructure components are capitalized and therefore no O&M costs are attributed to the infrastructure cost subcategory. Capital costs for software applications include software for the web portal, data warehouse, MDUS, Head End, security applications, and SAP. O&M costs for the software applications subcategory are resource and maintenance costs associated with software applications. Resources include internal and contractor IT resources who will be responsible for implementation of the IT technologies needed to support a Smart Meter rollout. All information technology costs were derived from the vendor pricing received through the RFP process.

4.2.1.4   Systems Integration

Total Estimated Costs: $87 million[12] (7% of total project costs).

Systems Integration (Capex): $55 million

Systems Integration (O&M): $32 million

Approximately $83 million is expected to spent during the Deployment Period.

Systems Integration Capex costs includes all the costs required to integrate the Companies' enterprise systems, including the Head End, MDUS, and SAP applications, in order to enable the sharing of data across applications. O&M costs include requirements identification and business processes definition and development. IBM's past experience serving as systems integrator for other similar implementation projects was used to estimate the cost inputs for this category. The estimate assumes that one systems integrator will handle business process design, architecture design, operational design, building and testing for the integrated system, vendor management, security and portal

[12] These costs do not include costs for the systems integrator's Project Management Office ("PMO"). Those costs are included as part of the program management cost category.

development in order to realize synergies associated with methodologies and staffing.

4.2.1.5 Business Staffing and Change Management Requirements

Total Estimated Costs: $169 million (13% of total project costs).

Business Staffing (Capex) $10 million

Business Staffing (O&M): $119 million

Change Management (Capex): $.4 million

Change Management(O&M): $39 million

Approximately $84 million is expected to be spent during the Deployment Period.

Business staffing costs include the labor and other related costs for incremental internal resources in various departments that support smart metering, including those departments needed to achieve the projected operational savings.[13] Change Management costs include the Companies' labor costs for training and internal and external communications, including support for any regulatory matters. These costs were estimated based upon Black and Veatch's experience with other communications plans, as well as through discussions with the Companies' communications department personnel and media cost information provided by those individuals.

4.2.1.6 Program Management

Total Estimated costs: $15 million (1% of total project costs).

PMO (Capex): $1.5 million

PMO (O&M): $13.5 million

Approximately $12 million is expected to be spent during the Deployment Period.

The systems integrator's Program Management Office ("PMO") is considered a capital cost and was derived from vendor pricing received through the RFP process. The systems integrator's PMO will be responsible for activities such as developing periodic scope, schedule and budgets for tasks to be performed

[13] For example, the Companies anticipate having to initially increase call center personnel before reducing staffing levels because of anticipated increases in call volume during the installation of the smart meters.

through the Deployment Plan. It will also be responsible for quality control of the smart meter deployment plan, driving the installation schedule, managing external stakeholders, and developing project sub-plans. The costs of the Companies' PMO, which will be responsible for overseeing the daily activities of the systems integrator's PMO, represent internal labor and related costs. These costs are classified as O&M expenses. These costs were estimated by IBM based upon its experience in being involved in such activities for other utility clients.

4.3 Operational Cost Savings

The Financial Model also projected potential cost savings that may be realized by the Companies through the installation of smart meter technology. These savings categories include (i) Meter Reading; (ii) Meter Services; (iii) Back Office; and (iv) Contact Center. All of the potential operational savings would be avoided costs. The potential savings projections were derived from an assessment of the impacts of business process changes that will occur as a result of the installation of smart meter technology. For each avoided cost, a determination was made as to whether it is categorized as an O&M cost or a Capex cost. A 20-year analysis period is used, with assumptions made based on information as currently known. The savings are cumulative over the 20 year period and are presented in nominal dollars. The estimated potential cost savings that the Companies believe may be quantifiable and verifiable are summarized below.

Figure 4.8
Estimated Potential Operational Savings Summary

Operational Savings		**20-year Cumulative (Nominal Value)**
Meter Reading		
Meter Reading O&M	$	368,955,939
Meter Reading Handhelds O&M	$	979,427
Meter Reading Handhelds Capital	$	2,359,063
Claims	$	474,860
Meter Services		
Meter Services O&M	$	9,961,302
Meter Services Handhelds O&M	$	44,420
Meter Services Handhelds Capital	$	947,290
Back-Office		
Back-Office/ Cust Accounting O&M	$	17,922,492
Contact Center		
Contact Center O&M	$	3,874,043
Total	$	405,518,837

4.3.1 Meter Reading

Estimated Potential Realizable Savings: $373 million (92% of the total projected program operational savings).

Reduction in work force: Approximately $369 million (O&M).
Reduction in hand held: approximately $3.3 million ($2.3 million Capex)
Claims: Approximately $0.5 million

Meter reading savings accrue through the elimination of the meter reading function, thus eliminating the need for manual meter readers and their handheld devices, and a reduction in related employee injuries and customer property claims. As a result of this reduction in work force, costs such as direct labor, overtime, fully loaded pension and benefits, and incentives are eliminated. Similarly, costs associated with employee uniforms, supplies, personal mileage and company cars can also be eliminated. Meter readers' handheld devices will no longer be needed and therefore capital costs associated with these devices, as well as the associated O&M maintenance costs can be eliminated over time. Finally, because there will be fewer customer site visits, there should be fewer OSHA and/or customer property damage claims.

The savings estimates are aligned with the smart meter deployment schedule and are based on the following assumptions:

- 100% of the meter reading positions will be eliminated by the end of 2022.
- The reduction in non-labor costs are proportional to the reduction in meter reading positions.
- Cost reductions are taken based on the percentage of meters installed, but lagged by one year.
- Annual retirement and attrition is estimated at a rate of three percent combined.
- Severance costs are estimated based on average current levels and will be subtracted from the calculated operational savings.
- Any necessary manual reads post-deployment will be executed by meter services staff.
- The average life of a handheld device is 10 years.
- The reduction in handheld devices is proportional to the reduction in meter reading positions and is aligned with the existing handheld replacement maintenance schedule and the proposed deployment schedule.
- Reduction in property damage and OSHA claims is proportional to the reduction in manual meter reading positions.
- No retraining of meter readers is assumed.
- Labor related budgets are escalated beginning in 2014 by 2.56% per year.
- There are no new projects/initiatives in 2013-2019 which may impact costs or staffing levels.

Tracking of Savings: In order to track meter reading savings, the Companies will track the actual reductions in the meter reader headcount as well as the number of meter readers moved to other smart meter related positions. Only those meter readers that move to new smart meter related positions (if any) will be excluded from the savings calculation. The Companies will also track average Full Time Equivalent ("FTE") labor costs including wages, benefits and payroll taxes for the meter reading personnel. These costs, net of any severance costs, would be compared against the baseline meter reading labor costs as of December 31, 2013. Apart from labor costs, the Companies will also track all changes in fleet costs, claims, personal mileage expense, equipment, materials and supplies expense related to meter reading. The Companies will track other applicable metrics, such as number of meter reading handhelds in service, number of handhelds retired and those moved to other uses. Actual costs in each of the above cost centers during each year of the Deployment Plan will be compared against the 2013 baseline levels.

4.3.2 Meter Services

Estimated Potential Realizable Savings: Approximately $11 million (3% of total projected program operational savings).

Reduction in work force: Approximately $10 million

Reduction in employee field tablets: Approximately $1 million (virtually all Capex)

Meter services activities include meter service personnel making customer visits for meter related issues and customer inquiries that need more technical explanations than can be provided by the customer contact center. Much of the potential cost savings is expected to arise as a result of reduction in work force and reduction in truck rolls. The installation of smart meters will reduce the need to dispatch a meter technician for activities such as (i) restoration of service upon receipt of customer payment (when service was disconnected for non-payment[14]); (ii) disconnection upon customer request or move out; and (iii) initiation of service upon customer request or move-in. The Companies will also be able to remotely "ping" the meters to determine if the meter is working. Customers will have access to more detailed information and it is assumed that many of the calls that required a technician to visit a customer will be able to be addressed by customer contact center personnel. With this automation and more detailed information being provided to customers, fewer Meter and Technical Support Services technicians will be needed, thus reducing workforce levels. Costs such as direct labor, overtime, fully loaded pension and benefits, and incentives will be reduced proportionately to the workforce reduction levels. Similarly, costs associated with employee uniforms, supplies, personal mileage and company cars can also be eliminated. Fewer technician computerized tablets will be needed and therefore capital costs associated with these devices, as well as the O&M maintenance costs can be reduced over time.

While, overall, there is a reduction in resource requirements, some of the existing personnel, or new personnel, will be needed to support new types of field service orders associated with smart meters, such as repairing communication

[14] The Companies will not implement this functionality for remote disconnect for non-pay partly due to Commission regulations and partly due to commitments made by West Penn in the Joint Settlement.

collectors. The possibility also exists that meter swaps could take longer due to more complex technology. Additional costs are expected in order to meet additional training requirements but cannot be estimated at this time. These costs would be netted against any realized savings.

The savings estimates are aligned with the smart meter deployment schedule and are based on the following assumptions:

- There will be a 99.5% reduction in tickets related to high bills, check readings, final reads for move outs, initial reads for move ins, and unblock dunnings
- Cost reductions are taken based on the percentage of meters installed, but lagged by one year.
- Labor savings are based on the average FTE labor rates by Company
- Training will be provided for personnel working with smart meters
- Current severance cost levels were assumed and will be netted against any cost savings.
- The reduction in tablets is proportional to the reduction in meter services positions
- The average life of a meter service tablet is 10 years.
- The Companies will continue to comply with Chapter 56 regulatory requirements prohibiting remote disconnect of service for non-paying customers without a site visit. Therefore, no savings associated with this function are included in the analysis.
- Non-labor operational savings are estimated to be proportional to the reduction of labor costs.

Tracking of Savings: The Companies will track meter services related expense in a way similar to meter reading expenses. In addition, the Companies will also track other metrics related to Meter Services that are relevant to the determination of savings associated with the meter service calls discussed above and compare them to 2013 baselines.

4.3.3 Back Office

Estimated Potential Realizable Savings: Approximately $18 million, all O&M (4% of total projected operational savings).

Back office activities involve resolution of high bill complaints and other billing related issues such as misreads, estimated reads, and move-in / move out reads.

With the installation of smart meters the Companies anticipate a significant decline in the number of estimated bills and read errors. Also the Companies currently receive postcard reads from some customers that require manual entry by an accounting clerk. Smart meters will eliminate this task. More accurate and up-to-date information available through the online portal should drive customers to validate information online rather than requesting a bill investigation. As a result of the reduction or elimination of these tasks, fewer employees will be needed in the back office for meter related activities, thus reducing labor and labor related costs, as well as equipment and supply costs currently incurred to support these employees.

Because customers are not familiar with smart meters and the information that will be provided through smart meters, the Companies anticipate that customer inquiries will increase before reaching a reduced steady state. Therefore, increases in costs may occur before net savings are achieved.

The savings estimates are aligned with the smart meter deployment schedule and are based on the following assumptions:

- A 99.5% reduction in manual re-bills will occur during steady-state, after deployment is complete, due to a reduction in estimation, manual reads, move in/move out errors, and stopped meters.
- There will be a 50% reduction in customer complaints requesting re-bills.
- A reduction in bill investigations is expected due to customer education and adoption of the online portal.
- Severance costs are based on current levels and will be netted against any savings.
- Average current labor rates by Company are assumed, with an escalation rate of 2.56%.

Tracking of Savings: The Companies will track the actual reductions in the back office headcount as well as the number of back office personnel moved to other smart meter related positions. The Companies will also track average Full Time Equivalent ("FTE") labor costs including wages, benefits and payroll taxes for back office personnel. These costs, net of any severance costs, would be compared against the baseline back office labor costs as of December 31, 2013. In addition to costs, the Companies will also measure other back office metrics that are relevant to determining back office savings and compare them against a 2013 baseline.

4.3.4 Contact Center

Estimated Potential Realizable Savings: Approximately $4 million, all of which is O&M (1% of total projected program operational savings).

The Contact Center is responsible for addressing all customer inquiries received through the Contact Center. More complex issues raised by the customer are forwarded to the Companies' back office for resolution. It is expected that there will initially be cost increases due to increased call volume arising from the installation of smart meters. The Companies intend to supplement current staffing levels through contract employees. Once smart meters are installed and customers become more familiar with the information that is being provided, it is expected that the call volume related to meter related customer inquiries will be reduced. Call volumes should be further reduced as customers become familiar with the use of the Companies' web portal that will include more detailed billing information, which can be verified on line. As a result, the Companies anticipate an eventual reduction in the number of employees needed to address meter related calls.

The savings estimates are aligned with the smart meter deployment schedule and are based on the following assumptions:

- Calls will increase annually during deployment, as customers are educated about their smart meters, new rate structures, and new capabilities available to them; calls will peak in 2018 and decrease thereafter. This assumes a 10% increase in calls resulting in a net increase in personnel in 2018 but a net decrease in personnel by 2022.
- During deployment, the Contact Center expects to see an initial increase in call handling times and volumes caused by both the learning curve for customer service representatives, and increased customer questions due to new smart meter system functionality and increased data volumes.
- Billing call volumes are assumed to decrease by 25% by 2020 due to customer education and customer adoption of the online portal.
- Basic calls will be addressed by contractors, while more complicated issues will be addressed by either the Companies' Contact Center or back office personnel.

Tracking of Savings: The Companies will track the actual back office headcount as well as the number of back office personnel moved to other smart meters related positions. The Companies will also track average Full Time Equivalent ("FTE") labor costs including wages, benefits and payroll taxes for the contact center personnel. These costs, net of any severance costs, would be compared against the baseline contact center labor costs as of December 31, 2013. In addition to costs, the Companies will also track other related metrics, such as contact center contractor costs, number of contact center calls, and the average duration of calls and compare them against a 2013 baseline.

CHAPTER 5. COST RECOVERY AND SELECTED REGULATORY ISSUES

This Chapter addresses cost recovery, bill impacts and other regulatory matters.

5.1 Riders and Costs

Consistent with provisions of Act 129, all four of the Companies have elected to recover smart meter technology costs on a full and current basis through a reconcilable automatic adjustment clause mechanism under Section 1307 of the Pennsylvania Public Utility Code.[15] By order entered June 9, 2010 at Docket No. M-2009-2123950, Met-Ed, Penelec and Penn Power received Commission approval to recover smart meter technology costs through a reconcilable adjustment tariff rider called the Smart Meter Technologies Charge ("SMT-C") Rider, which became effective August 1, 2010. By order entered June 30, 2011 at Docket No. M-2009-2123951, West Penn received Commission approval to recover smart meter technology costs through SMT-C Riders, which became effective September 1, 2011.

Aside from a compliance tariff update to the West Penn SMT-C Riders to include the remaining collection of $5.1 million of costs incurred in 2009 and 2010 associated with the development of a smart meter plan, the Companies are not proposing any changes to the SMT-C Riders and intend to continue to recover through these riders the costs associated with this Deployment Plan. These costs can be broken out into pre- and post-plan approval costs. The Companies anticipate this Deployment Plan will be approved by the Commission by September 30, 2013. Assuming this to be the case, the Companies, during the period January 1, 2013 through December 31, 2013, will incur costs associated with the regulatory process, including outside legal and consulting fees incurred during the litigation phase. Other costs such as those associated with the selection of the PMO and final negotiation of selected vendor contracts, will also be incurred during this period.[16] These costs have been estimated and have been included in the rider adjustment filing made on August 1, 2012 at Docket Nos. M-2009-2123950 and M-2009-2123951. Once this Plan is approved, the costs outlined in Chapter 4 will begin to be incurred, and will be collected though the SMT-C Riders. As noted previously, Incremental costs of providing smart meters upon request to Early Adopters were addressed through a separate filing and have been approved by Commission Secretarial Letter dated December 21,

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15 Pa.C.S. § 2807(f)(7).

16 On August 27, 2012, West Penn re-filed its proposed SMT-C rates effective January 1, 2013 to reflect an update to its Reconciliation Statement of Revenues and Expenses for the reconciliation year ended June 30, 2012.

2012 at Docket Nos. R-2012-2332803, R-2012-2332776, R-2012-2332785, and R-2012-2332790.

The Companies' Commission-approved SMT-C Riders consist of non-bypassable SMT-C rates designed to collect smart meter technology costs projected to be incurred during each calendar year, as well as recoup or refund, as applicable, under- or over-collections of actual smart meter technology costs from prior periods. The SMT-C rates are calculated separately for the residential, commercial, and industrial customer classes, and are expressed as a monthly customer charge to all metered customer accounts except for the rate applicable to West Penn's residential customer class, which is expressed as a dollar per kilowatt-hour charge.

The SMT-C Rider has two components. One is the current cost of smart meter technology projected to be incurred during each calendar year (referred to as the "Computational Year"). The second component is the reconciliation or "E-factor".

The types of projected smart meter technology costs recoverable under the SMT-C Rider include O&M expenses expected to be incurred during the Computational Year, an allocated portion of projected indirect costs during the same period that benefit all customer classes, and capital revenue requirements for assets placed in service. These costs are reduced by measurable and sustainable reductions in O&M and avoided capital costs attributable to the implementation of smart meter technology. Costs specific to a customer class are allocated to each customer class based upon direct assignment, and general costs are allocated to each of the Companies' respective customer classes based on the number of meters in each class as of June immediately preceding the Computational Year.

The E-factor component of the SMT-C Rider reconciles actual smart meter technology costs incurred by customer class to actual SMT-C revenues (excluding Gross Receipts Tax). The reconciliation is calculated monthly for each of the Companies and results in an over- or under-collection by customer class. The cumulative net balance per customer class, including interest, is included for recovery or refund.

SMT-C rates for all of the Companies are filed with the Commission by August 1st of each year, to be effective the following January 1st. Each of the Companies files with the Commission an annual report of collections under their respective SMT-C Rider within 30 days after June 30th.

5.2 SMT-C Rates

Met-Ed, Penelec and Penn Power: The SMT-C rates are flat rates that are calculated and stated separately for the residential, commercial and industrial customer classes. The rates are monthly, non-bypassable customer charges and are billed on that basis. Consistent with Commission Order entered June 9, 2010 at Docket No. M-2009-2123950, all customers eligible for the installation of a smart meter are charged, regardless of whether or not they currently have a smart meter installed at their premise.

The 2012 monthly SMT-C rates for these Companies' customers were as follows:

Med-Ed:

- Residential - $1.12 per customer
- Commercial - $1.12 per customer
- Industrial - $1.28 per customer

Penelec:

- Residential - $1.30 per customer
- Commercial - $1.33 per customer
- Industrial - $1.35 per customer

Penn Power:

- Residential - $1.36 per customer
- Commercial - $1.43 per customer
- Industrial - $1.43 per customer

The 2013 monthly SMT-C rates for these Companies' customers are as follows:

Med-Ed:

- Residential - $0.96 per customer
- Commercial - $0.96 per customer
- Industrial - $1.05 per customer

Penelec:

- Residential - $0.95 per customer
- Commercial - $0.97 per customer
- Industrial - $0.95 per customer

Penn Power:

- Residential - $0.91 per customer
- Commercial - $1.01 per customer
- Industrial - $0.95 per customer

West Penn. West Penn is also utilizing a SMT-C Rider and charging a SMT-C rate to metered customers during each billing month. Although commercial and industrial customers pay a flat monthly SMT-C rate, residential customers are charged a SMT-C rate based on the amount of electricity consumed. West Penn's SMT-C Rider recovers capital and O&M costs, provides West Penn with a return on capital investments, and collects costs and interest incurred in 2009 and 2010 associated with the development of a smart meter plan.

The 2012 monthly SMT-C rates for West Penn's customers were as follows:

- Residential - $0.00195 per kWh charged on each customer's monthly bill
- Commercial - $2.13 per customer per month
- Industrial - $2.66 per customer per month

The 2013 monthly SMT-C rates for West Penn's customers are as follows:

- Residential - $0.00276 per kWh charged on each customer's monthly bill
- Commercial - $2.43 per customer per month
- Industrial - $2.03 per customer per month

5.3 Customer Impacts and Other Regulatory Issues

Bill Impacts and Bill Presentment

The percentage impact on a typical customer's monthly bill for each of Met-Ed, Penelec, Penn Power, and West Penn's commercial and industrial customers is expected to be minimal since the rates are flat charges and are not based on kWh usage. The percentage impact to residential customers will vary based upon the magnitude of generation charges, but is expected to be minimal in comparison to total electric charges.

The Companies have analyzed and estimated the costs of this Deployment Plan over a 20 year period. The chart set forth below summarizes the estimated bill impacts by customer class over this period.

Figure 5.1
Monthly Bill Impacts (Nominal)

Op Co	Residential		Commercial		Industrial	
	Range	Average	Range	Average	Range	Average
MetEd	$1.04 - $4.58	$2.19	$1.12 - $5.37	$2.61	$1.11 - $7.04	$3.32
Penelec	$1.03 - $4.62	$2.25	$1.11 - $5.38	$2.63	$1.02 - $6.84	$3.26
Penn Power	$1.08 - $4.31	$2.27	$1.19 - $5.21	$2.81	$1.16 - $6.35	$3.42
West Penn Power	$1.32 - $4.91*	$2.61*	$1.60 - $5.68	$3.04	$2.39 - $7.61	$3.89

Reflects charges on a kWh basis rather than a flat charge.

While the SMT-C charges are currently displayed as a separate line item for all metered customers, the Companies are proposing to eliminate that presentation and instead fold the SMT-C charge into the overall distribution rate. Since the SMT-C is merely an extension of the Companies' meter and meter reading obligation – neither of which is a separately stated charge on customers' bills – the Companies see no reason to adopt a different view with respect to the SMT-C charges.

True-ups and Contingency

The return earned by the Companies through the SMT-C and SMT riders is only on capital investments associated with the smart meter solution included in this Deployment Plan. The return varies year to year and is based on the capital structure, with approximately half the weight on the return on equity and half the weight on the cost of debt. The capital structure, return on equity, preferred stock, and cost of debt utilized in the SMT-C Riders are calculated in accordance with Commission Order entered June 9, 2010 at Docket No. M-2009-2123950 for Met-Ed, Penelec and Penn Power; and the Commission Order entered June 30, 2011 at Docket No. M-2009-2123951 for West Penn.

To calculate each year's SMT-C rates, the Companies project the costs of implementing the Deployment Plan that are expected to be incurred during the Computational Year for each customer class. If the Companies spend more than they recover through the SMT-C Rider, the under-collection is collected through a customer class-specific reconciliation E-factor. If the Companies spend less than they recover through the SMT-C Rider, the over-collection is refunded through a customer class-specific reconciliation E-factor. Because the SMT-C Riders include a provision for an annual true-up to actual costs, the Companies do not incorporate any contingency into the yearly capital and O&M expenditure estimates.

West Penn Settlement Issues

In 2009 and 2010, West Penn incurred approximately $45.1 million of costs associated with the development of a smart meter plan. As part of its 2009 SMIP case, West Penn was authorized to collect $40 million of such costs through its SMT-C Rider. The remaining $5.1 million was challenged by some of the parties involved in that proceeding, who questioned whether it was appropriate to recover the $5.1 million through the SMT-C Rider. As part of the Joint Settlement, West Penn was permitted to file for and request recovery of these remaining costs in either its next distribution rate case and/or when it filed its smart meter deployment plan. West Penn has elected the latter and is now proposing to recover the remaining $5.1 million through the SMT-C Rider over the remaining 5.5 year amortization period (through February 28, 2017) previously approved by the Commission for recovery of the other $40 million. Recovery of the $45.1 million is supported by Act 129, the fact that the expenditure was not divisible given the nature of the West Penn Phase I and Phase II deliverables and the usefulness of those deliverables to the Pennsylvania Companies and West Penn during the grace period.

Legacy Meters

For meters that are removed or become obsolete due to the installation of smart meters ("Legacy Meters"), the Companies propose to retire the meters out of stock, continue their existing depreciation schedule unaltered over their remaining lives as a regulatory asset, and continue cost recovery through base rates. The rate base equivalent of the regulatory asset for Legacy Meters will continue to be included in the respective Company's rate base. This protocol would have no current impact on customer rates. For accounting purposes, the Companies are asking the Commission to approve an accounting treatment that would allow them to create a "regulatory asset" for the Legacy Meters with a recovery schedule equal to the remaining depreciable lives of the assets per the Companies' depreciation records.

CHAPTER 6. COMMUNICATIONS CHANGE MANAGEMENT AND TRAINING

6.1 Overview

During the Assessment Period, the SMIP Team was divided into nine workstreams, including two that involved "External Communications and Consumer Awareness Strategies" and "Change Management and Training". These teams combined efforts and have started to develop an Internal and External Education and Communications Plan ("Comm Plan"), a Change Management Plan and a Training Plan. Given that vendors and technology were just recently selected, and construction of the smart meter infrastructure will not commence until late 2013, the Companies will work to complete these plans prior to such construction commencing. Further, while these plans will be developed during 2013, the Companies cannot anticipate all of the issues that may arise throughout the Deployment Period, and issues identified as topics of interest may not be as significant to customers, employees and/or other interested parties as currently anticipated. Therefore the Comm Plan, Change Management Plan and the Training Plan will be designed with flexibility for adjustment to conditions as they arise. Below is a general outline of the strategies surrounding the development of each of these plans.

6.2 Comm Plan

6.2.1 Objectives

The Comm Plan will outline how the Companies will communicate their smart meter implementation plan to customers and other stakeholders. The objectives of the Comm Plan will be to:

- ***Provide communications support to ensure a successful smart meter deployment effort*** – Timely messaging support throughout the process is essential to a successful smart meter deployment effort, so that when customers have questions about the smart meters or the implementation plan, they know where to find answers.

- ***Take a customer-focused and cost-effective approach to communications*** – In the interest of customers, the communications effort must focus on the needs of the customers, which include timely messaging support, focused education efforts, targeting of key audience groups and an effective use of funds. The Companies' intentions are to support customers' needs throughout the deployment process. The Companies intend to provide an increasing level of communications, as the Companies ramp up deployment consistent with the three deployment stages discussed in Chapter 3.

- ***Develop and deliver consistent and effective messages that support this Deployment Plan by engaging customers*** – Such messages will communicate potential smart meter opportunities and reinforce those messages to key audiences.

- ***Keep employees, government officials, regulators, and media informed of significant developments*** – Part of creating consistent and effective messaging for customers must include maintaining a uniform understanding across all groups from which customers may receive or seek information, thus requiring communication updates to employees, government officials, regulators and media.

- ***Be responsive and provide the appropriate level of communications to customers and others*** – In a program that has the potential to impact a customer's electricity usage and billing experience, the Companies will be proactive and try to provide answers before questions need to be asked. And if asked, the Companies will attempt to provide prompt and accurate responses.

- ***Continue to develop communications to customers, employees and other stakeholders throughout the smart meter deployment program as major milestones are achieved*** – The Companies understand that, inevitably, the Comm Plan must develop and change throughout the deployment process as unexpected circumstances arise. Customers may have different primary concerns from what was expected and the deployment process may face different hurdles than those anticipated. Therefore, the Comm Plan will be designed with flexibility in mind.

6.2.2 Key Messages

The Comm Plan will develop key messages aimed at raising customer awareness concerning smart meters and smart meter technology effectiveness. The Comm Plan will address key objectives and will be based on the following themes:

- Smart meter technologies can be tools to enable customers individually to save energy and money by better managing their energy usage.
- Smart meters are capable of measuring electricity usage in greater detail and communicate that information to customers and their electric service provider.
- Over time, smart meters will enable customers to view detailed information on their electricity usage locally or through a secure website.

- Customer privacy and customer information will be protected.

6.2.3 Communication Challenges

During the Assessment Period, the following potential communications challenges were identified:

- Improving customer understanding of smart meters and awareness of the Companies' implementation plan.

- Building an understanding of and support for the smart meter solution and the Deployment Plan by government officials and the media.

- Managing customer expectations for smart meter functionality and potential benefits.

- Communicating with lower-income, vulnerable and elderly customers, as well as those who may have concerns regarding the costs related to smart meters and the benefits that may be realized.

- Effectively addressing frequently asked customer questions and concerns.

The SMIP Team will be working with interested stakeholders before the build-out of the smart meter infrastructure commences in order to try to resolve these challenges and to identify the key issues that should be addressed in customer communications.

6.2.4 Key Audiences

The SMIP Team has identified the following potential key audiences:

- Residential Customers
  - New construction
  - Early Adopters
  - Low Income Customers
  - Elderly
  - Special Needs
  - All other
- Commercial and Industrial
- Employees and Unions
- Government officials

- Regulators
- Suppliers
- Consumer Advocates
- News media
- Key community leaders
- Investment community
- Vendors

6.2.5 Communication Outreach

The SMIP Team anticipates utilizing direct customer communication, community outreach and media relations to engage and connect with target audiences. These communications may involve, when appropriate, the following:

- News releases
- Letters and other communications to major customers, local and state government officials and regulators
- Fact sheets, talking points and brochures outlining key messages distributed to customer contact centers and other personnel who are in contact with the public
- Customer mailings detailing the program and important key milestones
- The FirstEnergy external website
- Media contacts
- Editorial board meetings
- Newspaper advertisements
- Speakers Bureau presentations to local community groups
- Social media

6.2.6 Key Tactics

Potential internal tactics for the education of the Companies' employees may include the following:

- Employee training – Training will begin as a focused Contact Center activity and will eventually expand to all employees of the Companies. This is discussed in more detail in Section 6.4.
- Talking points and FAQs – Summary documents outlining the Companies' key messages and background information along with frequently asked questions will be distributed to external-facing employees to prepare them if a customer asks them a question related to

smart meters. These documents will address from a high level general questions about smart meters as well as questions about deployment.
- Feedback – An electronic method for employees to provide feedback to the smart meter team will be provided.

Potential external tactics may include the following:

- Welcome Notice – Customers receiving a smart meter will receive a notice (in letter form or by phone call, depending on the stage of deployment) about their upcoming installation and with information about the new meter.
- FirstEnergy Website – The FirstEnergy website will provide customers with access to a library of resources about smart meters and the deployment process, including fact sheets, FAQs and anticipated rollout timeline in service areas. This information will be designed to educate customers as well as address customer concerns.
- Customer Contact Center – Customers who reach out to the Contact Center with smart meter-related questions will be directed to a core group of trained employees or a team with more technical training, depending on the nature of the question.
- Feedback – Customers will have the opportunity to provide feedback on the effectiveness of communications through the Contact Center, which will be relayed to the communications team so that any necessary adjustments to the Comm Plan can be made.
- Collaborative – Interested stakeholders will be used as sounding boards and potential information channels for customer messaging.
- Phased Communications – Customers will receive a different level of communications depending on where they are in the smart meter deployment process. The details of these communications, including the content and manner in which the message will be disseminated will be shared with interested stakeholders prior to release.
- Media Outreach – The Companies will work with the media to communicate and manage expectations surrounding the functionality and deployment timelines. Modes and methods are still being evaluated.

6.2.7 Comm Team

FirstEnergy's communications, Contact Center and smart meter teams will draw on best practices and lessons learned from utilities across the country that are in various stages of smart meter deployment. It is expected that the Companies will form a dedicated team that will be responsible for answering smart meter inquiries, and addressing other smart meter communication issues as they arise.

6.2.8 Budget

The Companies have included a budget for the Comm Plan, which is discussed in Chapter 4.

6.3 Change Management Plan

The Company will need to adjust the mix of skills in its workforce for smart metering technologies and processes. Job responsibilities will change, and in some cases, roles will be eliminated. Change management is a structured approach to transitioning people, processes, and systems from a current state to a desired future state. This section outlines the process used to identify the key aspects of the Companies' Change Management Plan.

6.3.1 Objectives

The objectives of change management are to minimize the extent and duration of the disruption inherent in change, to promote understanding and commitment, and build the foundation for heightened levels of sustained performance.

6.3.2 Change Management Phases

The Companies' change management plan will consist of four phases: (i) strategy development; (ii) planning; (iii) pre-deployment; and (iv) deployment.

The strategy development phase occurred during the Assessment Period. It involved the creation of high-level strategy and guidelines. During this phase, stakeholders were interviewed and their roles identified. Additionally, the potential impacts of change were defined and assessed.

The planning phase builds on the groundwork laid by the strategy development phase. At the beginning of the planning phase, the target state is more clearly defined, the change impacts are re-assessed, and the change plan itself is developed. This will occur at the start of the PGP Stage and will be completed by September 30, 2013 – the assumed date by which the Commission will approve this Deployment Plan. During this phase, three broad activity streams will be developed:

> Managing change: focused on day-to-day activities and interpersonal communication
>
> Enabling and transforming the organization: focused on the structural, design, and skill-based aspects of change management

Building executive leadership and commitment: focused on organizational culture and stakeholder and leadership engagement

In the pre-deployment phase, the high-level structure, strategy, and plans of the previous phases cascade down to on-the-ground change efforts, business processes, organization charts, job descriptions, and performance objectives, all of which are defined at a detailed level. This will occur during the Solution Validation Stage and will be tested along with the smart meter infrastructure that will be constructed in Penn Power's service territory.

The deployment phase covers the implementation period during which the people, process, and system changes associated with the smart meter solution will be underway. This phase leverages the structure, plans, and processes established in the previous phases to ensure effective change management.

6.3.3 Change Management Team and Processes

Leadership alignment and sponsorship serves as a supporting activity to the entire change management plan. Coordinated change leadership efforts entail active and visible executive sponsorship, commitment to project goals at all levels, and frequent and open communications around the need for change that cascades through an organization via a change network.

The Companies' corporate sponsors will include FirstEnergy Vice Presidents (including Energy Efficiency, IT, Finance and Supply Chain). Executive level sponsors will include representatives from Meter/Field Services, Contact Center, Billing, Distribution Operations, and IT areas as well as regional Vice Presidents. These individuals will receive the training and support they need in order to be effective sponsors. Doing so will ensure that they are able to participate actively and visibly throughout the project, involve union leadership, and build a coalition of sponsorship with peers and managers, and communicate the Companies' Deployment Plan to employees and managers.

Below the executive sponsorship will be a network of Change Champions who will direct, plan, and guide the organization through change in a consistent manner. As a first step in the process, appropriate leaders for the program will be identified, and change priorities, opportunities, and constraints will be defined through leadership alignment interviews with senior leaders within the regional companies and corporate organizations. The program leaders will then produce a sponsor engagement plan, outlining the approach needed to demonstrate commitment to change at critical organizational levels, and developing key messages and sponsorship activities by relevant change area.

The SMIP Team is in the process of developing the change management structure described above.

It is anticipated that FirstEnergy change management processes already developed and proven through other major undertakings, such as mergers, acquisitions and major system installations, will be adopted and adjusted to the needs envisioned through deployment of the smart meter technology.

6.3.4 Budget

The budget for change management is discussed in Chapter 4.

6.4 Training Strategy

The challenges of change management are acutely felt throughout all aspects of the smart meter training process. To address these challenges, the SMIP Team has outlined a SMIP training strategy, designed to mitigate potential knowledge and skill gaps throughout the implementation of this Deployment Plan.

6.4.1 Objectives

The primary objective of the training courses and communication materials will be to provide timely, accurate, and consistent smart meter technology training, as needed, to all team members and impacted groups in a way that builds not only awareness and understanding, but also commitment to the program's success. The key objectives of this process are to identify key role changes due to the installation of smart meter technology and the impacts on required skills, knowledge, and abilities for key jobs. Coordination with business leadership, Human Resources, and Labor Relations to understand and successfully accomplish these objectives will be crucial.

6.4.2 The Approach

As part of this strategy, during the Solution Validation Stage, the organizational readiness team will partner with appropriate work streams and business units to facilitate the flow of information to all audiences impacted by the implementation of this Deployment Plan. Training will be delivered across the various work streams and within impacted business units.

The audiences for the training include all SMIP project team members and the Companies employees from impacted business units (namely Meter/Field Services, Contact Center, Billing, Distribution Operations, and IT). While the organizational readiness team will work with various subject matter experts to coordinate training upon request, ultimately, the business unit and work stream leads will be responsible and accountable for the accuracy and clarity of the training content and materials. Basic training will also be made available to employees not directly involved in smart meter activities so as to allow them to understand the primary components and impacts and be in a position to address basic questions from third parties if asked.

Depending on the particular operations environment, training delivery methods may include: computer-based training ("CBT"), instructor lead training ("ILT") in a classroom, Virtual ILT (over Sametime and Bridgeline), interactive distance learning, regular staff meetings, and safety meetings.

This training process has already been tested for the Post Grace Period training needs. Contact Center scripts and training of customer Contact Center employees occurred during the fourth quarter of 2012 in preparation for the commencement of the PGP Stage. Both the training and the processes and protocols underlying the training will be periodically reviewed for effectiveness, adjusting as deemed necessary.

6.4.3 Curriculum

Training courses and informational materials will be developed for one of three categories:

- Level 100: "SMIP Ambassador Training" consisting of general program-level material that is provided in emails, newsletters, meetings, and videos to all affected FirstEnergy employees
- Level 200: "Workforce Development Training" available for anyone interested in smart meters or AMI delivered by classroom and computer-based training that can be used as a prerequisite to smart meter/AMI job role training
- Level 300: "SMIP Training" provided to employees of highly impacted business units. This training focuses on deployment-based and system release-based training, including smart meter deployment information, company, employee and customer benefits, business process changes, new technologies, systems, and tools, and preparation for the new opportunities and skills demanded by new job roles

Additionally, the preparation of trainers will be critical to the success of this training strategy. This support will be achieved through a comprehensive train-the-trainer program. Prior to delivering end-user training, each trainer will receive training in:

SMIP functionality

- Instructional delivery and classroom management
- Business process flows performed within and outside of SMIP
- End-user training material and activities
- Troubleshooting in the training environment and contact for any support needs

The content of all training materials will be developed prior to the commencement of the Solution Validation Stage.

6.4.4 Budget

The training budget is included as part of the Change Management budget discussed in Chapter 4.

STATEMENT NO. 1

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
Docket No.

PENNSYLVANIA ELECTRIC COMPANY
Docket No.

PENNSYLVANIA POWER COMPANY
Docket No.

WEST PENN POWER COMPANY
Docket No.

SMART METER DEPLOYMENT PLAN

Direct Testimony
of
John C. Dargie

<u>List of Topics Addressed</u>

Overview of the Deployment Plan
Compliance With Act 129 and Other Requirements

<u>DIRECT TESTIMONY OF JOHN C. DARGIE</u>

I. <u>Introduction and Purpose of Testimony</u>

Q. Please state your name and business address.

A. My name is John C. Dargie and my business address is FirstEnergy Corp. ("FirstEnergy"), 76 South Main Street, Akron, Ohio 44308.

Q. Mr. Dargie, by whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as Vice President, Energy Efficiency. In addition to overseeing energy efficiency issues for FirstEnergy's ten electric distribution companies ("EDCs"), I oversee the development of the smart meter program in Pennsylvania. I report to the President of FirstEnergy Utilities, who is also a senior vice president within the FirstEnergy management organization, but also work closely with the presidents of each of FirstEnergy's individual EDCs on most matters.

Q. Please describe your professional background.

A. I began my career in sales at S.D. Myers, Inc., an engineering and transformer company in the Akron area, where I progressed through the company's sales organization for 20 years. I joined FirstEnergy in 1997 as Director of National Accounts. In 1999 I was promoted to Director of Sales and in 2002 was again promoted to Manager of Customer Support Services. In 2009 I became Manager of National Accounts and Portfolio Management and was promoted to my current position in 2011.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") (collectively "PA Companies") and West Penn Power Company ("West Penn") (collectively, with the PA Companies, "the Companies"). Unless otherwise stated, my testimony equally applies to all four Companies.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide the Companies' history with Act 129 and an overview of: (i) the filing; (ii) the Companies; and (iii) the Deployment Plan that is the subject of this proceeding.

II. Act 129

Q. Mr. Dargie, you previously referred to Act 129. When was that legislation enacted and what did it require?

A. Act 129 was signed into law by former Pennsylvania Governor Edward G. Rendell on October 15, 2008 and, amongst its other requirements, the Act directed EDCs with more than 100,000 customers to file plans with the Pennsylvania Public Utility Commission ("Commission") that provided for the installation of smart meter technology throughout their service territories over a period not to exceed 15 years.

Q. What steps did the Commission take to facilitate compliance with Act 129?

A. The Commission invited comments on a draft staff proposal and, on June 24, 2009, issued a detailed Implementation Order. In its Implementation Order, the Commission identified fifteen functionalities that it believed smart meter systems should support.[1] The Commission also established a 30-month "Grace Period" (i.e., until approximately the end of 2012 for most EDCs) during which an EDC was expected to "assess its needs, select technology, secure vendors, train personnel, install and test support equipment and establish a detailed meter deployment schedule ….". Finally, and in accordance with Act 129, the EDCs were directed to file initial smart meter plans by no later than August 14, 2009.

Q. Did the PA Companies comply with this directive?

A. Yes, they did. On August 14, 2009, Met-Ed, Penelec and Penn Power filed their Smart Meter Implementation Plan ("2009 SMIP"). In their filing, the PA Companies indicated that they would use the first 24 months of the Commission-authorized 30-month Grace Period (the "Assessment Period") to assess their needs, select technology, secure vendors, train personnel, install and test support equipment and establish a detailed meter deployment schedule and would then submit a deployment plan that described the results of the Assessment Period activities. The Deployment Plan that is the subject of this proceeding is the product of this work. West Penn also filed its own plan that I will discuss later in my testimony.

Q. Did the Commission approve the 2009 SMIP filed by the PA Companies?

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[1] Act 129 specified six mandatory functions and the PaPUC added nine more. The Implementation Order provided, however, that EDCs could seek a waiver of one or more of the additional nine functionalities if their adoption was shown not to be cost-effective.

A. Yes. By Order entered June 9, 2010 at Docket No. M-2009-2123950, the Commission approved the 2009 SMIP with several minor modifications.

Q. Why did the PA Companies not file their Deployment Plan at the end of the 24-month Assessment Period?

A. The Companies became aware in early 2012 that the vendors of certain smart meter technologies then under consideration were releasing improvements and enhancements to their technologies. To take advantage of this development, the Companies requested, and the Commission approved, an extension of the due date for the filing of the Deployment Plan until the end of 2012.

Q. Did West Penn also file a smart meter implementation plan ("WP 2009 SMIP") on August 14, 2009?

A. Yes, it did at Docket No. M-2009-2123951 ("WPP Proceeding"). However, during the pendency of the WP SMIP Proceeding, FirstEnergy and West Penn's corporate parent, Allegheny Energy Inc. ("Allegheny"), announced their intent to merge. As a result, the WPP SMIP was reassessed. The parties to the WPP SMIP Proceeding eventually negotiated and submitted a document entitled "Amended Joint Petition for Settlement of All Issues" ("Joint Settlement"). This Joint Settlement agreement, which, among other things, provided for a substantial deceleration in the deployment of smart meters from the schedule originally proposed by West Penn, was approved by the presiding Administrative Law Judge ("ALJ"). The ALJ's Initial Decision on Remand, in turn, was adopted by the Commission by Order entered June 30, 2011 in the WPP Proceeding.

Q. Did the extension for filing the Deployment Plan that was granted earlier this year to the PA Companies also apply to West Penn?

A. Yes, it did, although it was probably not necessary, given that, in the Joint Settlement, West Penn committed to refrain from filing its deployment plan before June 30, 2012. So technically by filing the Deployment Plan in this case on December 31, 2012, West Penn was already in compliance with the approved Joint Settlement.

Q. Did the Commission's Order in the PA Companies' 2009 SMIP filing direct them to address any specific issues in their Deployment Plan filings?

A. Yes. The Commission's Order in the PA Companies' proceeding directed those Companies to analyze and report back on various issues relating to sub-hourly metering. Companies Witnesses Iorio and Klein discuss those issues in their testimonies.

III. <u>The Filing</u>

Q. Please generally describe the filing.

A. Although there are four separate filings – one for each of the Companies – each is identical and includes a Joint Petition, with the Deployment Plan attached as an exhibit. The Deployment Plan is supported by testimony being provided by (i) myself; (ii) Mr. David W. Iorio, Director, Pennsylvania Smart Meter Project (Met-Ed/Penelec/Penn Power/West Penn Statement No. 2), who discusses the Companies' due diligence during the 30 month Grace Period, the recommended smart meter technology vendors and the construction and meter deployment schedules; (iii) Mr. Kevin A. Klein, an Associate Partner for IBM, Inc. ("IBM"), serving in the role of IBM's Program Director for the

Companies' SMIP project (Met-Ed/Penelec/Penn Power/West Penn Statement No. 3), who discusses the technical aspects of the recommended smart meter technology and architecture, and other hardware and software related issues; (iv) Mr. George L. Fitzpatrick, Executive Managing Director within the Management Consulting division of Black & Veatch Corp. ("B&V") (Met-Ed/Penelec/Penn Power/West Penn Statement No. 4), who addresses the financial aspects surrounding the Deployment Plan, including projected costs and estimated savings expected to be realized through the implementation of the Deployment Plan; and (v) Mr. Raymond E. Valdes, Advisor for Rates and Regulatory Affairs – Pennsylvania, who discusses cost recovery and other rate related matters, including customer bill impacts.

IV. FirstEnergy and the Companies

Q. Please generally describe the FirstEnergy corporate structure.

A. FirstEnergy is a diversified energy company headquartered in Akron, Ohio that has grown through various mergers and acquisitions, including its most recent merger with Allegheny. Among its many subsidiaries are ten electric utility companies – Met-Ed, Penelec, Penn Power and West Penn in Pennsylvania; Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company in Ohio; Jersey Central Power and Light Company in New Jersey; Monongahela Power Company in West Virginia; and The Potomac Edison Company in both West Virginia and Maryland. These ten electric utility operating companies comprise one of the nation's largest investor-owned electric systems, serving six million customers within a nearly

65,000 square-mile area of Ohio, Pennsylvania, New Jersey, West Virginia and Maryland.

Q. Please generally describe the Companies.

A. Met-Ed is a wholly owned subsidiary of FirstEnergy that provides service to approximately 555,000 electric utility customers in eastern Pennsylvania. Penelec is a wholly owned subsidiary of FirstEnergy that provides service to approximately 584,000 electric utility customers in central and western Pennsylvania. Penn Power is a wholly owned subsidiary of Ohio Edison Company, which, in turn, is a wholly owned subsidiary of FirstEnergy. Penn Power provides service to approximately 160,000 electric utility customers in western Pennsylvania. West Penn is a wholly owned subsidiary of Allegheny, which, in turn, is a wholly owned subsidiary of FirstEnergy as a result of the merger. West Penn provides service to almost 716,000 electric utility customers in western Pennsylvania. The overall diversity of FirstEnergy's Pennsylvania footprint can be seen in the Companies' varied service territory terrain and customer density. These factors, along with the need to develop a smart meter solution that will transcend state boundaries[2], creates significant challenges specific to the Companies. Additional challenges, not unique to the Companies, include the need to develop a deployment plan in an environment that continues to change as technology improves, vendors merge, and standards and guidelines are established on a regional and national level. These and many other factors were considered when designing the smart meter solution included in the Deployment Plan.

[2] The Companies are part of an integrated delivery system shared by FirstEnergy's Ohio, New Jersey, West Virginia and Maryland utilities.

Q. How is your organization structured?

A. My organization is comprised of two groups – the Energy Efficiency Group and the Smart Meter/Grid Group. The Smart Meter/Grid Group is currently comprised of approximately 37 employees, focusing on the assessment and potential development of smart meter and smart grid solutions throughout the FirstEnergy footprint. A significant portion of this group was assigned to the Smart Meter Implementation Plan Team ("SMIP Team") which, among other things, was charged with the development of the Deployment Plan.

Q. Please describe the SMIP team.

A. The SMIP Team is comprised of approximately 20 dedicated FirstEnergy personnel, along with internal support from various departments throughout the FirstEnergy organization, including rates, legal, supply chain and finance. This team also includes consultants from IBM and B&V, as well as personnel from various technology vendor representatives knowledgeable in areas involving key components and process designs of the core smart meter infrastructure solution. The SMIP Team was originally charged with the development of the PA Companies' 2009 SMIP that was filed at Docket No. M-2009-2123950. Upon approval of the 2009 SMIP, this team shifted its focus to the assessment of smart meter technology and the development of the recommended solutions included in the Deployment Plan for both the PA Companies and, after the merger with Allegheny, West Penn. Now that the Deployment Plan is filed, this team will transition away from the assessment and development stage and, instead, will start focusing on both regulatory support in this case and pre-deployment activities, such as negotiating contracts with selected vendors and selecting both a Systems Integrator and a Program Management Office ("PMO"). Once the Deployment Plan is approved, this team will predominantly focus on the management of the build-out of the smart meter solution and installation of meters consistent with the deployment schedule. We are in the process of developing an organizational structure to accommodate these tasks.

V. <u>The Deployment Plan</u>

Q. What is the difference between the SMIP and the Deployment Plan?

A. The 2009 SMIP, which was filed on August 14, 2009, basically set forth the plan that the PA Companies would follow during the 30-month Grace Period to develop the Deployment Plan that is the subject of this proceeding. The Deployment Plan, on the other hand, is the result of all of the work done during the Grace Period and sets forth the recommended smart meter solution, time lines for completion and other deliverables promised in the 2009 SMIP.

Q. Are each of the Companies submitting a Deployment Plan?

A. No. As I indicated previously, the four Companies are part of an integrated network of ten utilities in five states. Throughout the smart meter project, one of the goals was to develop a solution that not only was consistent with the needs of the four Pennsylvania utilities, but also could be expanded and be compatible with the potential needs of the other FirstEnergy utilities in other states, should there be a need or desire to do so. This approach also allowed the Companies to benefit from economies of scale and minimize costs by avoiding duplication of analyses, testing, systems and other efforts. As a result, the Deployment Plan represents a single solution for all four Companies.

Q. What were some of the other goals of this project?

A. In addition to the one I just discussed, other overall goals of this project were to (i) develop a plan that complies with all statutory and regulatory requirements; (ii) develop a tested solution that provides the greatest functionality at the lowest overall cost to customers after factoring in various risks; and (iii) develop a cost recovery solution that keeps customers' monthly bills reasonably low. I believe that the recommendations included in the Deployment Plan accomplish all of these goals.

Q. Were there any significant events that affected the development of the Deployment Plan?

A. Yes, there were two. The first was the merger between FirstEnergy and Allegheny. In the Joint Settlement of the WPP SMIP, West Penn made certain commitments. Upon completion of the merger during the first quarter of 2011, the smart meter needs of West Penn, along with West Penn's commitments made through the Joint Settlement, were incorporated into the analyses and other work being done by the SMIP Team. Also the work performed by West Penn while developing the WPP SMIP allowed the SMIP Team to reduce some of the analyses it otherwise would have had to do.

The second significant event involved technological advancements by some of the key vendors under consideration. While the SMIP Team was in the process of finalizing the Deployment Plan for the original filing deadline of June 2012, several smart meter vendor finalists each independently indicated their intent to release improved smart meter system technology in the spring of 2012. Because of its imminent release, the Companies requested, and were granted, a six month extension of their filing deadline in order to test this new technology. Through testing, the SMIP Team found that the enhancements to the technology provided better two-way communication capability and more flexibility throughout the FirstEnergy Pennsylvania footprint. Therefore, the Deployment Plan incorporates this enhanced technology as part of the recommended solution.

Q. Please describe the Deployment Plan.

A. The Deployment Plan is comprised of six chapters, each of which addresses in more detail the topics being discussed by the various witnesses in this case, and is based on the most current information available at the time of this filing. Chapter 1 provides an executive summary of the Plan. Chapter 2 discusses the Companies' due diligence during the 30-month Grace Period, while Chapter 3 describes the recommended vendors, technology solution and construction and deployment schedules. Chapter 4 discusses the projected costs and estimated potential operational savings that may be achieved, while Chapter 5 discusses cost recovery and customer bill impacts. Finally, Chapter 6 discusses the Companies' strategies surrounding their Communications, Change Management and Training Plans.

The Deployment Plan sets forth a three stage deployment schedule that is discussed in Chapter 3. The deployment schedule anticipates that approximately 98.5 percent of all smart meters will be installed between January 1, 2014 and December 31, 2019 ("Deployment Period") with the remaining 1.5 percent of the installations, which are expected to be difficult either due to their location or communication problems, being installed no later than 2022.

In the first stage (the “Post Grace Period” Stage), the Companies will provide smart meters for all new service requests received on or after January 1, 2013 and for all customers requesting a smart meter prior to their scheduled installation date. In the second stage (the “Solution Validation” Stage), expected to start in late 2013 and continue through early 2017, the Companies will build out the infrastructure needed to install smart meters and a 60,000 meter “mini-system” in Penn Power’s service territory which will be tested and “debugged” as unanticipated installation, communications and functionality problems arise. Once any encountered problems are corrected, the Companies will commence the build out of the remainder of the system in the third stage – the Full Deployment Stage – which is expected to start in early 2017. This will involve multiple teams building out the system on parallel paths in each of the four Companies’ service territories, focusing first on the most densely populated areas in each.

The projected cost of this project over a 20 year period is estimated to be approximately $1.258 billion (nominal), with approximately $752 million (nominal) spent during the Deployment Period. These costs will be recovered through the already approved SMT-C Rider for each of the Companies. The projected savings that may be realized over the life of this project are estimated at $406 million (nominal).

Q. In your opinion, does the Deployment Plan meet all of the commitments made by the Companies?

A. Yes. As part of their 2009 SMIP, the PA Companies committed to include in the Deployment Plan the following information:

(i) A detailed long term timeline, with key milestones, which is included in Chapter 3 of the Deployment Plan;

(ii) A smart meter solution, which is described in Chapter 3 of the Deployment Plan;

(iii) The costs of such a solution, along with an assessment of potential cost savings, which is addressed in Chapter 4 of the Deployment Plan;

(iv) A network design solution, which is included in Chapter 3 of the Deployment Plan;

(v) A communications architecture design solution, which is discussed in Chapter 3 of the Deployment Plan;

(vi) A training assessment and proposed curriculum, which is discussed in Chapter 6 of the Deployment Plan;

(vii) A cost recovery forecast, which is discussed in Chapter 5 of the Deployment Plan;

(viii) A transition plan including communication to employees and consumers, which is discussed in Chapter 6 of the Deployment Plan; and

(ix) A detailed, tiered roll-out plan, which is discussed in Chapter 3 of the Deployment Plan.[3]

Additionally, as part of the Joint Settlement, [4] West Penn agreed to

1. Decelerate the deployment of smart meters from its original schedule which, based on the schedule included in Chapter 3, it has done.

2. Utilize some or all of the 30 month grace period authorized by the Commission to reevaluate back office systems, system-wide networks and its installation plan, redesigning its solution accordingly. This was accomplished as part of the due diligence, which is discussed in Chapter 2 of the Deployment Plan

3. File a revised smart meter implementation plan. which shall include a deployment plan, anticipated to be filed no earlier than June, 2012. This filing demonstrates compliance with this provision.

4. Include in the revised smart meter implementation plan a cost benefit analysis for deployment of smart meters to at least 90% of West Penn's customers by December 31, 2018. This is discussed by Companies Witness Fitzpatrick and is addressed in Chapter 4 of the Deployment Plan.

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[3] SMIP Order at 6-7.

[4] *In re Petition of West Penn for Expedited Approval of its Smart Meter Technology and Installation Plan*, Docket No. M-2009-2123951, Joint Petition, ¶¶ 15-29 (March 9, 2011).

5. Perform, at a minimum, the following analyses during the grace period:

- A benchmark comparison of the costs of its revised, proposed network development and installation plan to those approved for several comparable companies;
- An updated analysis similar to that submitted by Nevada Power to the Nevada Commission at Docket No. 09-07003;
- An estimate of improvements in the Company's distribution system reliability in terms of cost savings, such as increased efficiency in responding to outages;
- An estimate of savings in supply costs, including capacity and energy costs;
- An estimate of the likely participation and electricity usage reductions of customers in response to the programs and rate offerings enabled by smart meters; and
- An evaluation of the merits of deploying In-Home Devices ("IHDs") in conjunction with the deployment of smart meters; agreeing not to deploy, prior to May 31, 2013, any such IHDs in support of West Penn's Energy Efficiency and Conservation ("EE&C") Plan that was then pending before the Commission for consideration in Docket No. M-2009-2093218.

Companies Witness Fitzpatrick addresses these commitments in his testimony.

6. Promote and encourage customer requests for smart meters in order to achieve deployment of up to 25,000 smart meters between 2010 and 2013 and submit to interested parties, as part of its report on the status of its EE&C Plan, information on progress towards achieving that goal. The Companies included this information in their October 15, 2012 EE&C report filed in Docket No. M-2009-2093218.

7. Recover costs associated with the development of the revised smart meter plan consistent with the provisions of the Joint Stipulation. Cost recovery is addressed in Chapter 5 of the Deployment Plan and by Companies Witness Valdes in his testimony.

8. During the grace period, collect and provide non-confidential data to interested parties on its low income and vulnerable customers, including elderly heads of households and households that have been identified as having a disabled person who requires electricity as a medical necessity, which shall include customer load shapes and usage characteristics, to the extent such customers are identified, and a granular analysis of the load

shapes and usage characteristics to a sample of customers, to the extent sufficient data to perform such an analysis exists. Companies Witness Fitzpatrick discusses compliance with this commitment in his testimony.

9. During the grace period, review data collected on low income and vulnerable customers with interested parties in order to examine the potential for the development of specific smart meter programs for these customers. Companies Witness Fitzpatrick also discusses the work done in this area in his testimony.

10. Refrain from using the remote disconnect feature for involuntary terminations and work with other parties to vet the issues surrounding such a policy prior to implementation. None of the Companies have initiated practices related to remote disconnect for non-pay and will not do so until these issues are resolved either through a Commission directive or through a process vetted with interested parties.

11. Meet with registered interested parties, at least semi-annually during the development of the Deployment Plan. The Companies held stakeholder meetings on various topics on August 17, 2011, December 8, 2011, February 21, 2012, May 31, 2012, October 18, 2012 and December 13, 2012. The December 8, 2011, May 31, 2012 and December 13, 2012 meetings provided updates on the development of the Deployment Plan. The August 17th and February 21st meetings addressed sub-hourly metering issues. The other meetings were held with parties interested in low-income and vulnerable customer issues.

Finally, as I already mentioned, the Commission asked the PA Companies to address certain issues relating to sub-hourly metering. Those issues are addressed by Companies Witnesses Iorio and Klein.

Q. Do you believe that the recommended solutions included in the Deployment Plan meet the requirements of Act 129 and the Commission's June 24, 2009 Implementation Order?

A. I have been told that Act 129 requires the Companies to provide smart meters to all of their customers by 2025, and that these meters must have certain functionalities that the Commission describes in its Implementation Order. As set forth in Chapter 3, all customers will have smart meters installed before 2025 and, as explained by Companies Witness Klein, the meter solution selected by the Companies is capable of providing all functionality as required by the Commission. While I am not an attorney, based upon this information, yes, I believe that the recommended solutions included in the Deployment Plan meet these requirements.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATEMENT NO. 2

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
Docket No.

PENNSYLVANIA ELECTRIC COMPANY
Docket No.

PENNSYLVANIA POWER COMPANY
Docket No.

WEST PENN POWER COMPANY
Docket No.

SMART METER DEPLOYMENT PLAN

Direct Testimony
of
David W. Iorio

<u>List of Topics Addressed</u>

Development of Deployment Plan
Evaluation of Technology and Testing
Selection of Vendors
Recommended Smart Meter Solution
Sub-Hourly Metering

DIRECT TESTIMONY OF DAVID W. IORIO

I. Introduction and Purpose of Testimony

Q. Please state your name and business address.

A. My name is David W. Iorio. My business address is FirstEnergy Corp. ("FirstEnergy"), 76 South Main Street, Akron, Ohio 44308.

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

A. I am employed by FirstEnergy Service Company as Director, Pa Smart Meter Project.

Q. Please summarize your educational background and professional experience.

A. I graduated from Westminster College in 1985 with a Bachelor of Science Degree in Accounting. I have worked for FirstEnergy or one of its predecessor companies for approximately 38 years, having started out as a meter reader and gradually working through various assignments of increasing responsibility until I was assigned to the Pennsylvania smart meter project in 2009 as the project manager. In December, 2012, I was promoted to my current position and, once it is approved, I will be responsible for the overall implementation of the Deployment Plan that is the subject of this proceeding.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory agencies?

A. Yes, I testified in Docket No. M-2009-2123950, the proceeding in which the Commission approved the 2009 Smart Meter Implementation Plan ("2009 SMIP") for Metropolitan

Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), and Pennsylvania Power Company ("Penn Power") (collectively, the "PA Companies").

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

A. In broad terms, the purpose of my testimony is to explain how the PA Companies and later West Penn Power Company ("West Penn") (collectively "the Companies") developed the smart meter solution included in the Deployment Plan attached as an exhibit to the December 31, 2012 Petition filed in this proceeding. I will (i) discuss how the Companies assessed their existing and prospective smart meter needs; (ii) describe how available smart meter technologies were evaluated and tested; (iii) explain how qualified vendors were identified and selected; (iv) summarize the Companies' recommended smart meter technology deployment schedule; and (v) address certain issues involving sub-hourly metering. Unless otherwise stated, my testimony applies equally to all four Companies. Further, rather than reiterating sections of the Deployment Plan in my testimony, sections to which I refer are incorporated into my testimony by reference.

Q. Will you be referring to any exhibits in your direct testimony?

A. Yes. Attached to my testimony is Exhibit DWI-1, a graphic depiction of the meter installation schedule included in the Deployment Plan, which was prepared under my direct supervision. Exhibit DWI-2 consists of the responses to certain issues and questions relating to sub-hourly meter reads which the Commission directed the Companies to study as part of the Deployment Plan. I have also included Appendix A, which is a copy of the PA Companies' 2011 Annual Progress Report filed with the

Commission in July 2011. Finally, I am co-sponsoring the Deployment Plan attached to the Joint Petition as Exhibit A, primarily supporting Chapter 2 and portions of Chapter 3 of that document.

II. <u>Development of the Deployment Plan</u>

Q. How did the Companies go about developing the Deployment Plan?

A. As Companies Witness Dargie explains, the Commission authorized a thirty-month grace period ("Grace Period") during which time a team comprised of employees of the Companies with a variety of skill sets, subject matter experts from IBM, additional consultants from Black & Veatch and various technology vendor representatives knowledgeable in the design and installation of smart meter networks ("SMIP Team") developed the Deployment Plan.

Q. What was the SMIP Team tasked to do?

A. The SMIP Team was tasked to develop a smart meter solution that provided the functionality mandated by Act 129, as well as the additional functionality included in the Commission's Implementation Order that could be implemented in a timely and cost effective manner. In this effort, the work previously completed by West Penn in support of its initial accelerated smart meter plan was incorporated following the merger of FirstEnergy Corp. and Allegheny Energy, Inc., and proved to be beneficial in developing the solution.

Q. How did the SMIP Team organize itself?

A. The SMIP Team was subdivided into nine substantive work groups, designated and charged with the following tasks:

Solution Framework: To provide strategic vision, technical subject matter expertise, and risk mitigation guidance using an end-to-end vision from the architecture, vendor, schedule and business perspectives.

Current State: To identify the Companies' business units and functions that could be impacted by the deployment of smart metering and to gather data regarding the nature of those impacts. The current state provided the baseline for current business operations that could be compared to a future state under a smart metering solution.

Vendor Strategy: To identify various technologies and vendors that could be utilized in the final smart meter solution and to narrow the field to a manageable number of candidates for lab and field testing.

Technology Evaluation and Test Lab: To test various smart meter technologies under both lab and field conditions.

Future State: To develop a strategy to guide the full scale implementation of smart meters by identifying the technical requirements for the various business departments, processes, procedures, equipment and infrastructure that could be affected.

Network Communications: To identify the characteristics of each of the Companies' service territories and the potential communications infrastructure that would accommodate such characteristics.

External Communications and Consumer Awareness Strategies: To develop a communications plan for the Commission, interested stakeholders and consumers, with the goal of managing expectations, providing pertinent status updates and vetting, where appropriate, issues identified during the development of the Deployment Plan.

Change Management and Training Strategies: To develop a plan that bridges the Current State of the Companies to the Future State.

Project Management Office: To provide overall project management and coordination.

Q. What tasks did these various subgroups undertake during the Grace Period?

A. A summary of key workstream activities was set forth in the Annual Progress Report filed with the Commission in July 2011. As noted previously, a copy of that report is attached to my testimony as Appendix A. In addition to the activities listed, the SMIP Team also: (i) conducted a series of strategic planning sessions with senior and middle management executives from various business units of the Companies; and (ii) visited several other utilities that have deployed smart meter systems to discuss their technology solutions and lessons learned.

III. <u>Evaluation and Testing of Technology</u>

Q. What are the key components of a smart meter system that the SMIP Team had to investigate and evaluate during the Grace Period?

A. As explained in Chapter 2 of the Deployment Plan, the integration of smart meters and supporting technology is known as Advanced Metering Infrastructure ("AMI"), the key components of which include: (i) smart meters; (ii) a backhaul communications network; (iii) a Head End/collection engine; and (iv) a Meter Data Management System ("MDMS"). In addition, customers, at their option, may install a Home Area Network, or "HAN," within their residence that can facilitate the remote control of home devices and provide customers with near real-time non-validated consumption data. Companies Witness Klein discusses the components of this infrastructure in more detail in his testimony.

Q. How did the Companies identify the specific components/pieces of equipment which, when integrated, would best provide the functionality needed to comply with Act 129 and the Commission's requirements?

A. Each of the working groups that I mentioned previously assessed the current state of smart meter infrastructure, company technology "baselines," and available technology and vendors. Based on their analysis, the work groups prepared an initial solution architecture.

Q. Did the diverse nature of the Companies' service territories present any unique challenges to the design of the smart meter network?

A. Yes. The Companies' service territories include both metropolitan and rural areas in a terrain that includes both mountains and valleys. In some instances, there are fewer than 10 meters per square mile; and in urban areas, meters may be installed in underground parking facilities, or within concrete structures through which communications by radio frequency may be difficult. As a result, the Companies' evaluation of smart meter solutions included consideration of the extent to which a solution could be effectively deployed in multiple environments and incorporate new technology for communication with radio frequency "challenged" or hard-to-reach areas.

Q. How did the Companies develop a short list of possible vendors?

A. The SMIP Team issued Requests for Information ("RFIs") in 2010 to potential vendors of the AMI components: smart meters, backhaul, Head End, MDMS, and meter deployment services. The responses were then analyzed and evaluated based on various criteria, including compliance with Commission requirements, reliability, and indicative pricing.[1] In addition, some preliminary testing of various vendors' technologies was performed in the Companies' test labs and, for meters and backhaul, in field environments as well. The RFI process is more fully discussed in Chapter 2 of the Deployment Plan.

[1] A list of the criteria used by the SMIP Team appears in Chapter 2 of the Deployment Plan.

Q. What did the SMIP Team do with the data and other information obtained through the RFI process?

A. In the second and third quarters of 2011, the SMIP Team developed and issued Requests for Proposals ("RFPs") for five separate AMI categories, including smart meters, backhaul, Head End, MDMS, and meter deployment. The RFPs generally tracked the format of the RFIs, but were more comprehensive in terms of inquiring into the precise solution proposed and the vendors' experience in delivering that solution elsewhere.

Q. How were the RFP responses handled?

A. As more fully described in Chapter 2 of the Deployment Plan, the RFP responses underwent a multi-step evaluation. First, the SMIP Team performed an initial evaluation and selected certain vendors in each category for further consideration. The responses then underwent an objective and a qualitative evaluation. Finally, a "short list" of respondents was created based on these evaluations and several respondents were invited in to make oral presentations. Once the SMIP Team completed the evaluation process, it identified the technologies that met the business, technical and functional requirements and continued testing to confirm that the selected components actually performed as claimed.

Q. How did the testing proceed?

A. Each major piece of equipment and technology was tested in both a test lab and in the field to ensure that it interfaced properly with the other infrastructure components and would provide the functionality required by Act 129 and the Commission's Implementation Order. The field assessment involved the installation of approximately

400 meters in the Met-Ed service territory and 300 meters in West Penn's service territory and enabled the SMIP Team to test the network under varying demands and topographical conditions. The testing procedures utilized are discussed in greater detail in Chapter 2 of the Deployment Plan. The equipment and technologies being tested were also evaluated on the basis of both quantitative and qualitative criteria.

IV. Selection of Vendors

Q. How did the Companies ultimately select vendors to supply the components of their smart meter systems?

A. The rigorous vendor evaluation process that I just described allowed the Companies to: (i) eliminate some vendors from further consideration and develop a "short list" of vendors; and (ii) gather and analyze key information about the remaining vendors, including comparisons of vendor performance based on criteria developed by the Companies. The Companies conducted extensive qualitative and quantitative assessments of the vendors and their offerings, including visits to other utilities to examine implementation solutions. As a result of the evaluation process, the Companies made the following vendor selections:

Smart Meter System Component	Selected Vendor
Meter Vendor	Itron
Head End Vendor	Itron
MDMS	Itron
Backhaul	AT&T / Verizon

Additional information on the selected vendors and their technologies is provided in Chapter 3 of the Deployment Plan.

V. Recommended Solution

Q. What are the Companies recommending as their smart meter solution?

A. The Companies have both a technical and deployment schedule solution. Companies Witness Klein discusses the recommended technical solution in his testimony. I am supporting the recommended deployment schedule which will have approximately 98.5 percent of all meters installed between January 1, 2014 and December 31, 2019 ("Deployment Period") with the remaining 1.5 percent installed no later than the end of 2022, assuming the Deployment Plan is approved by September 30, 2013. While the vast majority of activity is expected to take place during the Deployment Period, the Deployment Plan includes three distinct stages: (1) a Post-Grace ("PGP") Stage; (2) a Solution Validation Stage; and (3) a Full-Scale Deployment Stage. These stages are more fully discussed in Chapter 3 of the Deployment Plan.

Q. How long does the PGP Stage last and what will occur during this time?

A. The PGP Period commences on January 1, 2013 and continues through the end of 2022. This stage addresses not only the need to provide smart meters for all new service requests received on or after January 1, 2013 ("New Construction") and for all customers requesting a smart meter prior to their scheduled installation date ("Early Adopters"), but also addresses contract negotiations and final RFPs and other pre-deployment activities.

For new construction on all new temporary and permanent service applications received on or after January 1, 2013, the customer will be provided with a radio frequency smart meter included in the recommended technology solution, which will eventually be able to communicate with the smart meter network infrastructure. Customers will not be billed additional fees for the meter or other installation costs beyond those charged to all metered customers through each Company's Smart Meter Technologies Charge Rider discussed by Companies Witness Valdes. During the period between smart meter installation and the build-out of the smart meter network in the area where a New Construction smart meter installation occurs, neither the communication functions of the meter nor smart meter functionality will be available and meter reads will be done manually using existing meter reading and billing procedures.

For Early Adopters, once the customer pays the incremental costs for the meter and related installation, a Point-To-Point ("PTP") smart meter that meets the basic Act 129 functionality requirements will be installed. This smart meter will communicate via public cellular network and will provide on-line access to validated meter data within 24-48 hours and access to unvalidated meter data via a direct access interface to a device that is part of the customer's HAN. Meter reads for billing purposes will continue to be done manually using existing meter reading and billing procedures until the smart meter network infrastructure becomes available at the customer's location and the PTP meter is replaced with the smart meter selected as part of the smart meter technological solution.[2]

[2] Tariff provisions implementing Companies' proposals for Early Adopters were filed with the Commission on October 31, 2012 and approved on December 21, 2012. *See* Docket Nos. R-2012-2332803; R-2012-2332776; R-2012-2332785; R-2012-2332790.

During the period between the filing of the Deployment Plan with the Commission and approval of the plan by the Commission (anticipated to be by September 30, 2013) , the SMIP Team will negotiate final terms and conditions with the selected vendors, select a systems integrator ("SI") and program management office ("PMO") through the RFP process described in Chapter 2, finalize contracts with the SI and PMO and work with consultants and selected vendors to develop construction schedules, all with the goal to have everything in place to start construction of the smart meter infrastructure upon approval of this Deployment Plan.

Q. When will the Solution Validation Stage occur and what will take place during this time?

A. The Solution Validation Stage incorporates two activities: the build out of the infrastructure needed to install smart meters and a testing period in which a "mini version" of the end to end smart meter solution is constructed and tested prior to full scale deployment. This stage is expected to start in late 2013 after Commission approval of the Deployment Plan and continue through early 2017.

The build out begins upon Commission approval of this Deployment Plan (currently anticipated for the fourth quarter of 2013) and will continue for approximately three years. During this period, the Companies will commence construction of the smart meter solution infrastructure, or "backbone" for the "mini system". This will involve the installation of meters, collectors, network communications, and meter data management systems for testing.

As the infrastructure is built, the Companies will start to install meters in Penn Power's service territory. Approximately 5,000 meters will be installed in 2014; 15,000 in 2015; and 40,000 in 2016, so as to allow for development of back office business processes, testing of scalability and resolution of communication, functionality and installation problems encountered in a contained and controlled environment, thus minimizing costs of deployment and customer frustration. Only after all such problems are resolved will the Companies commence the final stage, Full-Scale Deployment, currently anticipated to commence in early 2017.

Q. Why are the Companies first building a fully integrated system only in Penn Power's service territory?

A. The Companies have service territories that vary in terms of terrain, customer density and climatic conditions. The relatively low customer density in much of these service territories, the diverse terrain and the changes in weather between the mountains and valleys present system design challenges that would not be encountered by other utilities that serve major cities. Thus, the SMIP Team decided upon a deployment strategy that would validate the mesh network solution described by Mr. Klein and the functionality and reliability of all selected equipment prior to rolling this solution out to the 2 million Pennsylvania customers that the Companies serve. Penn Power's service territory was selected because it possesses the topographical, climatic and customer density diversity most representative of the four Companies' most challenging conditions and is integrated more closely with West Penn's information technology systems.

Q. Why not correct the problems on the system as they are encountered while building out a system-wide smart meter network?

A. The cost and efforts of resolving problems as you conduct a full-scale deployment are much greater than if these "bugs" are resolved in a controlled environment. This approach also mitigates customer frustration by minimizing the number of customers affected by any encountered problems and advances the Companies' change management processes throughout the organization by preparing them for Full-Scale Deployment.

Q. When would Full-Scale Deployment commence under the Companies' proposal and how long would it last?

A. Full-Scale Deployment will commence upon resolution of all problems encountered during the Solution Validation Stage and will continue until all meters are installed on or before December 31, 2022. During this stage, the remainder of the smart meter infrastructure will be concurrently built in each of the Companies respective service territories, starting with the most populated areas first. As I explained previously, the Companies expect to install approximately 98.5 percent of all meters between January 1, 2014 and December 31, 2019, with the remaining 1.5 percent of the meters being installed thereafter through December 31, 2022. The 1.5 percent of the installations represent those installations that may require alternative communication solutions or involve difficult to reach locations such as remote hunting cabins.

Q. In order to achieve this level of deployment by the end of 2019, how many meters will be installed per day?

A. On average, 3,000 meters per day, five days per week, would be installed. I have included on attached Exhibit DWI-1 a graph of the meter deployment schedule.

Q. Why are the Companies proposing this particular deployment schedule?

A. As Companies Witness Fitzpatrick explains in his testimony, the deployment schedule that I describe best balances costs and risks of deployment.

Q. In its June 9, 2010 Order at Docket No. M-2009-2123950, the Commission directed the Companies to study several issues associated with sub-hourly meeting, conduct a stakeholder meeting, and prepare a cost/benefit analysis. Did the Companies implement the Commission's directive?

A. Yes. Exhibit DWI-2 sets forth the issues identified by the Commission and the Companies' conclusions with respect to each issue following meetings with the parties to the proceedings at Docket No. M-2009-2123950 and other stakeholders. An initial stakeholder meeting was held on August 17, 2011, where the Companies solicited perspectives on sub-hourly metering needs. Generally, the Companies found that there was likely to be relatively low customer interest in sub-hourly data, but that the customers (and vendors) who would use that information desired data as near to real-time as possible.

Following the initial stakeholder meeting, the Companies considered a variety of sub-hourly metering arrangements and network storage, engineering support, hardware/software, and backup systems. Companies Witness Klein discusses this cost analysis in his testimony.

As explained by Witness Klein, in light of the high costs of implementing sub-hourly metering across the entire smart meter system solution for all customers, the Companies concluded that access to sub-hourly data could be reasonably achieved through the customers' use of an in-home device. The Companies held a second stakeholder meeting on February 16, 2012, at which this proposed solution was discussed and received positively by stakeholders.

Q. Mr. Iorio, does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Annual Progress Report of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company on Their Smart Meter Technology Procurement And Installation Plan

(For the year ended June 30, 2011)

Docket No. M-2009-2123950

July 27, 2011

For Informational Purposes Only – Filed Pursuant to the Pennsylvania Public Utility Commission's Implementation Order Entered June 24, 2009 in Docket No. M-2009-2092655

Table of Contents

1.0 Introduction and Background

On August 14, 2009, Metropolitan Edison Company ("Met Ed" or "ME"), Pennsylvania Electric Company ("Penelec" or "PN") and Pennsylvania Power Company ("Penn Power" or "PP") (collectively, "Companies") filed their Smart Meter Technology Procurement and Installation Plan ("SMIP Plan"). This Plan provided both a short- and longer-term plan for compliance with Act 129 of 2008 ("Act 129"), which requires each electric distribution company ("EDC") with more than 100,000 customers to develop a plan to fully deploy smart meters within fifteen years of Plan approval (June 2010-June 2025). The SMIP Plan as approved by the Pennsylvania Public Utility Commission ("Commission"), included a 30-month grace period during which the Companies indicated that they would assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment and establish a detailed smart meter deployment schedule consistent with the statutory requirements -- including a deployment plan for: (i) the grace period; (ii) post grace period/pre-build out completion; and (iii) build out period. As indicated in the SMIP Plan, these tasks are being performed during the first 24 months of the grace period (Assessment Period.) At the end of the Assessment Period, the Companies will submit to the Commission a supplement to the SMIP Plan ("referred to herein as the "Deployment Plan") that includes among other things: (i) a detailed long term time line, with key milestones; (ii) a potential smart meter solution; (iii) the projected costs of such solution, along with an assessment of benefits; (iv) a network design solution; (v) a communications architecture design solution; (vi) a training assessment and proposed curriculum; (vii) a cost recovery forecast; (viii) a transition plan including communication to employees and consumers; and (ix) a detailed tiered roll-out plan.[1] The Companies have partnered with IBM and Black & Veatch Corporation to develop the SMIP Plan.

In a June 9, 2010 Order entered in Docket No. M-2009-2123950, the Commission approved the Companies' SMIP Plan, directing them to submit an annual Smart Meter Progress Report ("Report"). Pursuant to this directive, the Companies submit this Report, which provides a status update on the activities surrounding the Assessment Period from the commencement of the project in July 2010, through June 30, 2011 ("Reporting Period").

As more fully discussed below, the Companies are generally on track with the schedule set forth in the SMIP Plan. However, since the filing of the SMIP Plan, FirstEnergy Corp. ("FirstEnergy"), the Companies' parent company, merged with Allegheny Energy, Inc. ("Allegheny Energy"). Allegheny Energy owned West Penn Power Company ("West Penn"), which submitted its own smart meter plan to the Commission in Docket No. M-2009-2123951. While the Companies intend to integrate the needs of West Penn into the Deployment Plan that will be submitted at the end of the Assessment Period and that will describe a comprehensive plan to provide smart meter services to every customer throughout the FirstEnergy Pennsylvania footprint (including West Penn) ("FirstEnergy PA Footprint") by 2025, this Report focuses solely on the Companies' SMIP Plan activities through June 30, 2011.[2]

[1] While the Companies anticipate providing this information to the degree possible, given the ever changing smart meter landscape, the Companies cannot guarantee that the Deployment Plan will include every detail for final implementation of the plan that will ultimately be approved.

[2] Inasmuch as the merger between FirstEnergy and Allegheny Energy was only recently consummated, and West Penn received a ruling on its proposed settlement submitted in their smart meter filing (Docket No. M-2009-2123951) on June 30, 2011, the Companies have only performed a preliminary review of West Penn's work to date and a preliminary assessment of its needs. As of the date of this Report, these needs have not been integrated into the Assessment Phase strategy, but will be included in the Companies' Deployment Plan that will be filed in June, 2012.

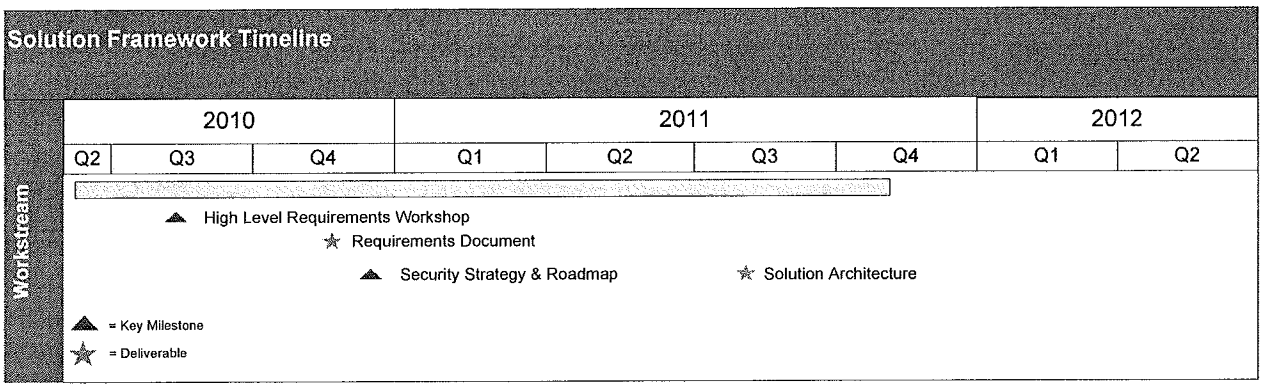
The Companies' SMIP project was subdivided into eight substantive subgroups, or workstreams: (i) Solution Framework; (ii) Current State; (iii) Vendor Strategy; (iv) Technology Evaluation and Test Lab; (v) Future State; (vi) Network Communications; (vii) External Communications and Consumer Awareness Strategies and (viii) Change Management and Training strategies. The major tasks performed during the Reporting Period and current status of each are discussed below.

2.0 Workstream Status Update

2.1 SOLUTION FRAMEWORK

Purpose: To provide strategic vision, technical subject matter expertise, and risk mitigation guidance using an end-to-end vision from the architecture, vendor, schedule, and business perspectives. The Solution Framework activities are focused on setting the overall framework for the Deployment Plan.

Solution Framework Timeline:



Key Workstream Activities to Date:

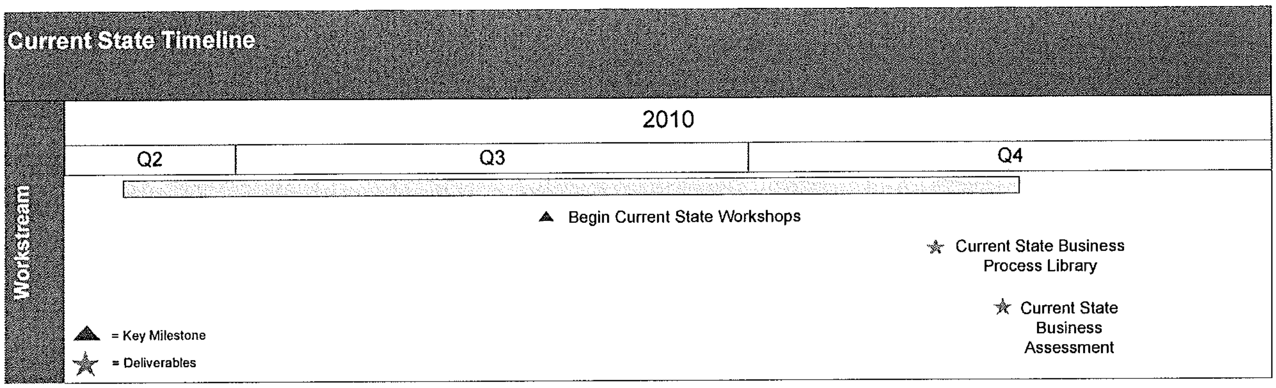
- Developed an overall system engineering and architectural view as related to the SMIP Plan.
- Validated the requirements for the Deployment Plan. Starting with Act 129 requirements, the team collected all known internal and external requirements into a single repository and then identified areas where more clarity was needed or potential gaps existed.
- Collected information regarding currently available options for customer facing and supplier portal solutions.
- Identified and evaluated existing methods and potential solutions for the collection of customer energy consumption data.
- Provided program-wide technical governance support in various areas, including design authority, establishment of program wide technical standards and guidelines, and quality assurance criteria.
- Collected and confirmed requirements for security and standards compliance for the smart meter solution.

Current Status of Workstream: All tasks to date have been completed on schedule. It is anticipated that the Solution Architecture associated with this workstream will be completed by the fourth quarter of 2011. Integration of security, telecom, privacy and network infrastructure are in progress.

2.2 CURRENT STATE

Purpose: To perform an initial discovery of the Companies' current state business activities across multiple business units that may potentially be impacted by the implementation of smart meters. The Current State Assessment activities involved identifying and confirming business units, functions, budgets, staffing, business processes, applications, contracts and other related data required for eventual inclusion in the end-state products of the business case and business planning.

Current State Timeline:



Key Workstream Activities to Date:

This workstream categorized its tasks into three major activities: (i) Data Gathering; (ii) Impact Analysis; and (iii) Validation of Data. Each is discussed below.

Data Gathering Activities:

- Identified the Companies' business units that may potentially be impacted by the deployment of smart metering.
- Created and distributed data request templates for internal use throughout FirstEnergy.
- Analyzed responses to internal data requests and held internal workshops for further discussion of potential impacts.

Impact Analysis:

- Created workshop agendas and materials based on existing business process documents, current business applications, and other pertinent information.
- Conducted data review and analysis workshops with FirstEnergy resources by business unit to identify and assess business processes, financial reporting structures, computer and other systems, and staffing.
- Identified and documented the current state architecture and technical design based on the solution architecture workshops with business units.
- Based on the above information, developed smart metering impact analysis documents to identify potential impacts to the Companies' business units.

Validation

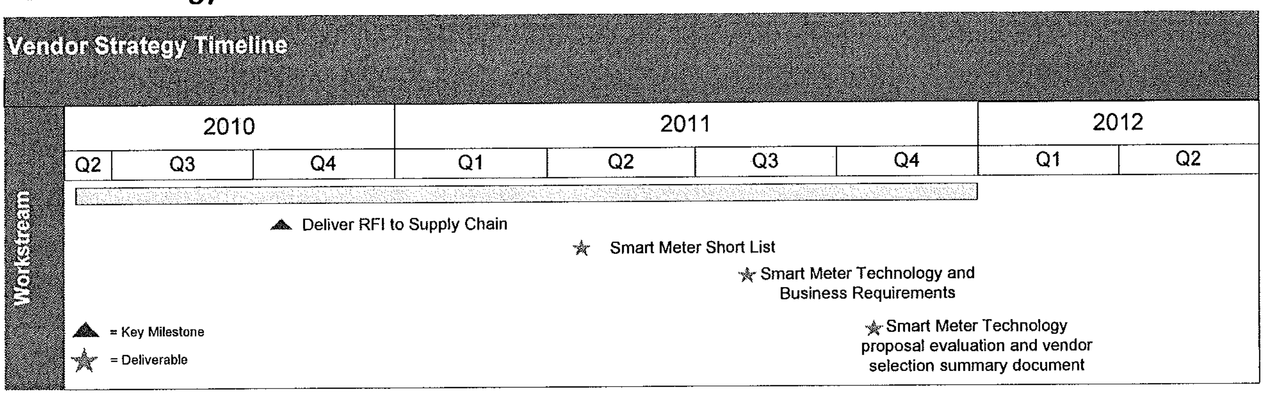
- Performed a detailed review of data provided by business units to ascertain accuracy, reasonableness and completeness of data provided. Compared results to benchmarked data from other jurisdictions.
- Held follow-up meetings with various business unit subject matter experts to validate findings.

Current Status of Workstream: All tasks have been completed.

2.3 VENDOR STRATEGY

Purpose: To identify various technologies and vendors that may be used in the final smart meter solution, narrowing the field to a manageable number for lab and field testing. This includes both a Request for Information ("RFI") and Request for Proposal ("RFP") process including "request instrument" development, and evaluation of the same components proposed by the vendors.

Vendor Strategy Timeline:



Key Workstream Activities to Date:

In the SMIP Plan (at page 37), the Companies indicated that they would start a ten month vendor and technology selection process in September, 2010. Since September, 2010, this workstream has accomplished the following:

- Identified six functional components of the smart meter project which are included within either Technology or Service Providers: (i) Technology – Head End; (ii) Technology - Meter Data Unification Synchronization System ("MDUS"); (iii) Technology - Smart Meter; (iv) Technology - Backhaul Communications; (v) Service Providers - Field/Device Installers; and (vi) Service Providers - System Integrator.
- Developed a multi-step vendor selection strategy:
  - Step 1: RFI for technology components (Head-End, MDUS, and smart meter) (Completed)
  - Step 2: RFP(s) for smart meter components (Head-End, MDUS, smart meter, Field Installation and Backhaul) (Preliminary work in progress)
  - Step 3: RFP(s) for a System Integrator (Preliminary work in progress)
- Defined functional requirements for Head-End, MDUS, and smart meter components.
- Defined NIST Security requirements for Head-End, MDUS, and smart meter components.

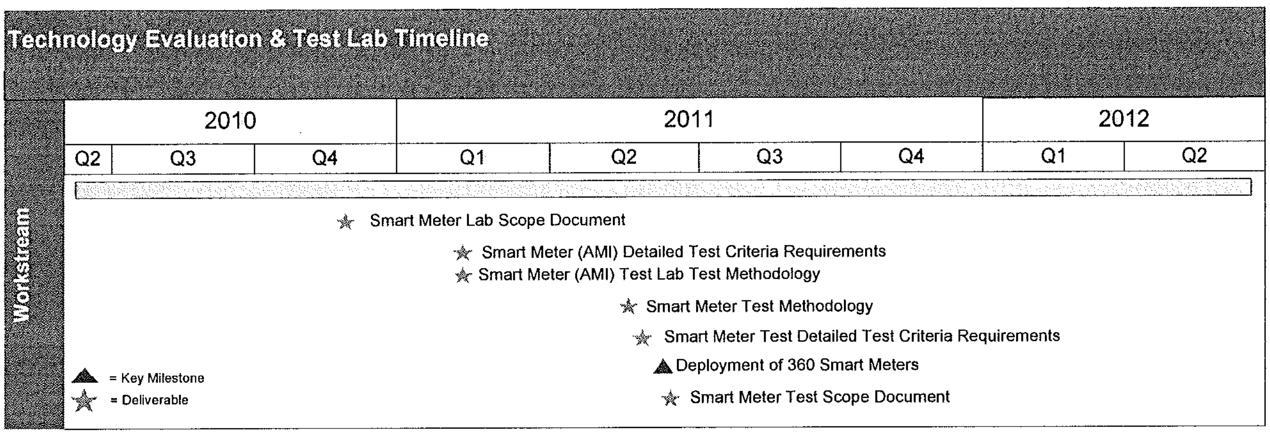
- Defined a price template for smart meter components.
- Completed Step 1 - RFI design, development, and distribution for Head-End, MDUS, and smart meter
  - Developed vendor evaluation criteria (by component)
  - Evaluated RFI response for each component (e.g. vendor, qualifications, requirements, price)

Current Status of Workstream: Steps 2 and 3 of the vendor selection began in June 2011 and will build upon the RFI effort completed in Step 1, refining requirements based on the RFI experience and the results from the testing (both in the lab and in the field). The RFP for smart meters, MDUS, and Head-End is planned to be released to the vendors in the fall of 2011 followed by evaluation of vendor proposals.

2.4 TECHNOLOGY EVALUATION & TEST LAB

Purpose: To test various smart meter technologies under both lab and field conditions.

Technology Evaluation, Test Lab and Field Assessment Timeline:



Key Workstream Activities to Date:

In the SMIP Plan, the Companies indicated that they would perform a technical trial, which will involve the deployment and testing of 5,000 to 10,000 smart meters prior to December 31, 2013, and will consist of two major components: 1) a smart meter test lab; and 2) a field test.

Smart Meter Test Lab:

- Developed a technology evaluation plan.
- Set up a test lab and obtained smart meter equipment from various vendors for evaluation in both the test lab and the field.
- Created test scenarios in the test lab based on Commission mandated functionality and FirstEnergy needs.
- To date, two MDUS vendors, three head-end vendors and three smart meter vendors (representing the landscape of viable technology solutions) have been tested under numerous scenarios, with defects reported to vendors and retests conducted as necessary.

- This workstream continues to evaluate the MDUS. Several options are being evaluated in the Smart Meter Test Lab. These systems have been in this environment since late 2010 and will continue to be tested through 2012 to ensure that they can meet the criteria listed in the SMIP Plan.
  - Each MDUS vendor has been fully integrated into a smart meter system to support end-to-end testing from the meter to the back-end CIS and SAP Enterprise Resource Planning ("ERP") in preparation for field testing.
  - To support the billing determinant calculation testing, disconnect/reconnect functionality and other complex smart meter event management processes, FirstEnergy upgraded the SAP smart meter functionality to ERP Enhancement Package 5 (EhP5) and CRM (Ehp1) in the 1st quarter 2011. The SAP ERP and CRM systems are enabled to support ongoing business end to end process testing in the test lab and during the upcoming field assessment.

Field Assessment:

- Field deployment/ testing commenced in June, 2011:
  - 360 Met-Ed customers in two meter reading routes have been deployed for initial testing in the field.
  - Up to 5,000 smart meters will be deployed for additional field assessment before the end of 2013.
  - In addition to the Companies' deployment testing activities, in its recently approved settlement, West Penn committed to deploy up to 25,000 smart meters during the West Penn grace period.[3] At this time the Companies expect to leverage information gathered through West Penn's deployment, rather than expand their deployment beyond 5,000 smart meters.

Electronic Data Interchange (EDI) Certification

- In response to the Smart Meter Procurement and Installation Docket No. M-2009-2092655 (Implementation Order), FirstEnergy has been working with the Electronic Data Exchange Working Group ("EDEWG") to develop Smart Meter Data Exchange Standards. The working group has focused on reviewing industry requirements and discussing data exchange standards for current and new business processes. Representatives from FirstEnergy participated in five EDEWG meetings that have been conducted prior to the end of the Reporting Period. This working group will be submitting a separate report to the Commission at a future date.

Current Status of Workstream: Smart meter test lab and field assessment activities are continuing as planned. During this field and lab testing, the Companies also evaluated their current EDI processes and procedures. The Companies concluded that their current EDI transactions effectively provide data at the account level. However, due to the volume of data, current EDI transactions are not effective at providing meter level data. The Companies will continue to work with the EDEWG Sub-Team to explore other methods to support the need for new historical interval usage data at the meter level and to resolve other outstanding issues surrounding business processes and data exchange standards.

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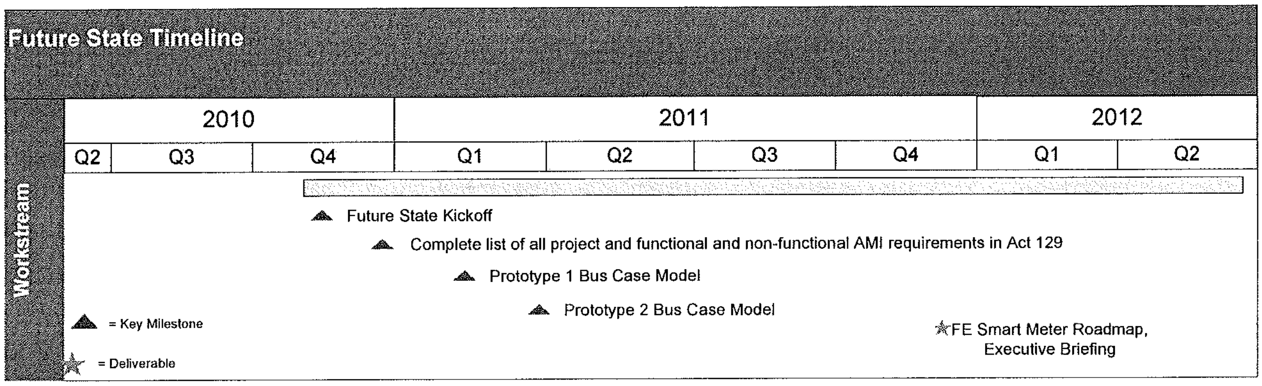
[3] *Petition of West Penn Power Company d/b/a Allegheny Power for Expedited Approval of its Smart Meter Technology and Installation Plan, Docket No. M-2009-2123951, Appendix A (October 19, 2010).*

2.5 FUTURE STATE

Purpose: To develop a strategy to guide the full scale smart meter implementation by identifying the business and technical requirements for the various business departments, processes, procedures, equipment and infrastructure that may be affected by the implementation of a smart meter solution.

Future State Timeline:



Key Workstream Activities to Date:

- Facilitated twenty future state design workshops to ascertain the business unit impacts, risks, and business process transformation that would be needed as part of the smart meter deployment.
- Developed an impact analysis based on results of the design workshops, resulting in the identification of 300 unique impacts that would affect the Companies' business units post implementation.
- Developed a smart meter analysis based on the impact analysis and the solution architecture design. Developed a gap analysis between current state environment and smart meter requirements.
- Assessed privacy and security issues and solutions related to smart meter implementation programs.
- Identified future state data architecture.
- Created security tracking and reporting tools and metrics.
- Defined future state requirements, architecture and skills/capabilities to support the Companies' smart metering program.
- Identify smart meter implementation options and prioritize them based on planning level requirements. (In Progress)
- Develop an end-to-end recommended solution(s) for smart meters, in order to define the best solutions and protocols for the smart meter network, smart meters, software, hardware and cyber security. (In Progress)
- Develop a comprehensive plan detailing the proposed integrated solutions (Hardware, software, networks). (In Progress)
- Develop an overall implementation approach and a release plan for smart meter implementation. (In Progress)

- Develop detailed cost (capital and O&M) estimates to support future state requirements and architecture, including but not limited to hardware costs, software costs, maintenance costs, operational costs and licensing costs. (In Progress)
- Develop the Deployment Plan's detailed business case and corresponding Commission filing. (In Progress)

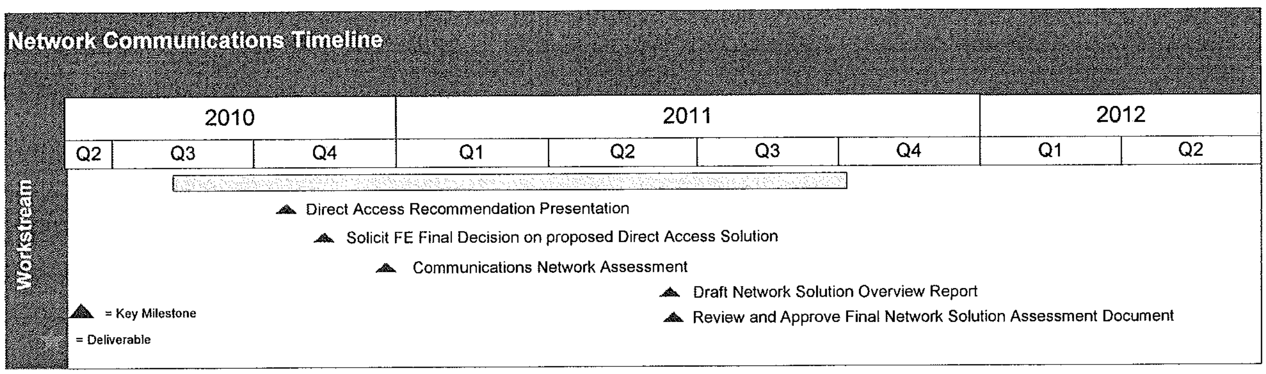
Current Status of Workstream:

The above tasks, as indicated, have either been completed or are in progress at this time.

2.6 NETWORK COMMUNICATIONS

Purpose: To identify the characteristics of each of the Companies' service territories and match potential communication infrastructure that will accommodate such characteristics.

Network Communications Timeline:



Key Workstream Activities to Date:

The network communications workstream has completed a conceptual design of the communications backhaul network[4] for the entire pre-Allegheny FirstEnergy Pennsylvania footprint by looking at each of the three Companies individually and selecting sample areas in each of their respective service territories so as to obtain a varied sample of field conditions. Key activities involved in the development of this design include:

- Reviewing existing data, including various reports, technology roadmaps, vendor presentations and projects planned or in some stage of progress, and summarizing the results.
- Creating a master map profile of the Companies' Pennsylvania footprint by:
  - Identifying FirstEnergy's existing infrastructure assets (towers, substations, fiber networks, etc.) and potential third party assets and mapping them to determine viable options for potential locations to host smart meter backhaul equipment;
  - Selecting 24 sample areas based on topography variations within the various service territories and four meter density areas: (i) urban, (ii) suburban, (iii) rural and (iv) remote; and
  - Factoring in design guidelines and other information obtained through the RFI process.

[4] The communications backhaul network is the wide area network (WAN) that provides data transport between the AMI local area network (LAN) that will need to be constructed in each and every neighborhood of FirstEnergy's Pennsylvania service territories, and the MDUS).

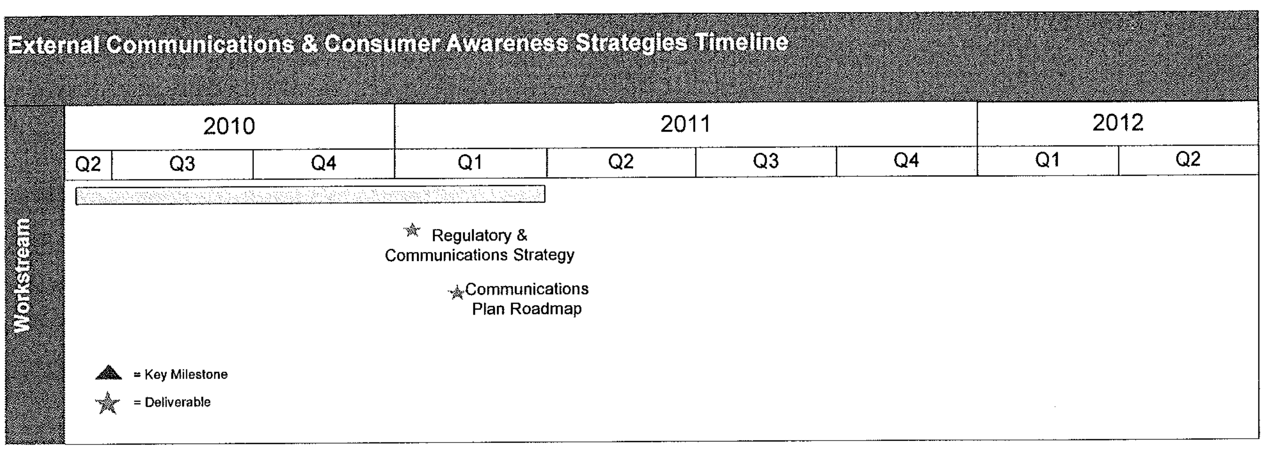
- Reviewing three LAN technologies in the various sample areas - (i) power line carrier ("PLC"); (ii) licensed radio frequency ("RF") high profile tower based; and (iii) unlicensed 900 MHz RF mesh.
  - RFI responses were reviewed and the proposed smart meter LAN designs and design guidelines were extracted and used as a baseline in the creation of independent smart meter LAN conceptual designs in the sample areas.
- Analyzing and developing conceptual designs for candidate LAN solutions in representative sample areas.
- Completing budgetary cost estimates for each sample area, the results of which have been extrapolated from the sample areas to the Companies' Pennsylvania Footprint.

Current Status of Workstream: Since neither a purely private, nor purely public, solution is feasible to reach 100 percent of the required sites, it is expected that the final conceptual designs will be a hybrid, or blend, of the viable options selected for each and every takeout point. This analysis is underway and is expected to be completed sometime during the fourth quarter of 2011.

2.7 EXTERNAL COMMUNICATIONS & CONSUMER AWARENESS STRATEGIES

Purpose: To develop a deployment phase communications plan for external parties, including the Commission, interested stakeholders and consumers, with a goal of managing expectations, providing pertinent status updates, and vetting, when appropriate, issues that are identified during the Assessment Period.

External Communications Timeline:



Key Workstream Activities to Date:

Developed a Regulatory and External Stakeholder Communications Strategy, which included the following elements:

- SMIP Communications Strategy Rationale
- Communications Response Continuum
- Stakeholder Landscape and FirstEnergy Personnel Roles

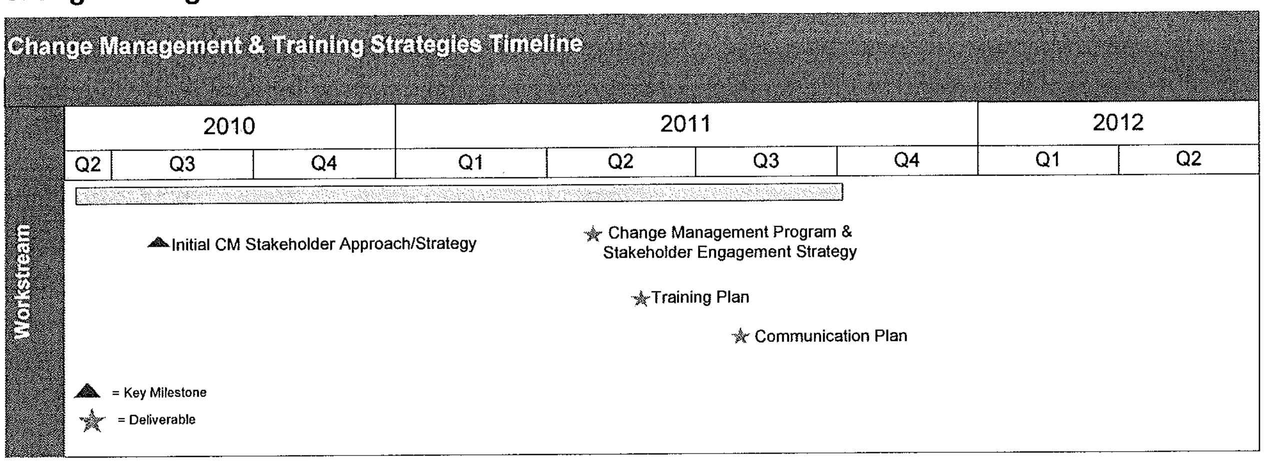
Current Status of Workstream: Currently this workstream has moved into a second phase of activities, including the use of customer focus groups and surveys, the development of a post-

Deployment Plan/pre-Deployment approval phase communications plan, the implementation of internal FirstEnergy executive outreach workshops to update senior management on Deployment Plan progress, and the implementation of field assessment activities related to the smart meter assessment roll-out. The Companies also attempted to hold a stakeholder collaborative meeting on June 30, 2011, in which they were to address sub-hourly metering and provide an update to interested parties. Due to stakeholder schedule conflicts this meeting had to be postponed. The Companies have re-scheduled this collaborative meeting for August 17, 2011.

2.8 CHANGE MANAGEMENT & TRAINING STRATEGIES

Purpose: To develop a plan that bridges the current state of the Companies to the future state, including the identification of stakeholders, future state impacts training needs and communications needs.

Change Management Timeline:



Key Workstream Activities to Date:

The Companies indicated that an on-going change management assessment would commence in April, 2010. To date the following activities have occurred:

- Identified key stakeholders.
- Surveyed numerous FirstEnergy employees at all levels throughout the organization.
  - Survey addressed organizational readiness, communication needs, training needs and perceived customer attitudes.
  - Results are being used to develop an overall change management plan outline which includes topics such as the methodology, approach, key activities and timeline for managing the transition to smart meters.
  - Developed and defined the Companies' 'Strategy for Change.'
  - Completed a 'Change Characteristic' assessment of the Companies and key impacted business units.
  - Identified Companies' risks/challenges/ consequences if change is managed poorly.

- Developed a proposed Change Management Team structure to support the transition to smart meters.
- Developed a Change Management Roadmap.

Current Status of Workstream: All tasks are complete, except for the development of a training plan, which is in progress.

3.0 Deployment Status

The Commission's Order identified three distinct time frames for which the Companies were to design deployment plans: (i) during the grace period (Order, p. 7); (ii) post grace period/pre-build out completion (Order, pp. 10); and (iii) system-wide deployment (Order, p. 14.) The status of each of these tasks is summarized below.

During Grace Period – The Companies are utilizing the MV-90 technology to offer smart metering to customers upon customer request and at the customer's cost. These meters have the capability to provide consumption data in 15 minute intervals and provide time of use information.

To date, no customer has requested a smart meter and thus no MV-90 meters have been required. The Companies have installed approximately 60 smart meters in their test lab and will be field testing approximately 300 meters on two preselected meter reading routes starting in June, 2011. During 2012 the scope of the field assessment will be expanded through the installation of approximately 3,000 smart meters. In 2013, the installation of approximately 2,000 smart meters is planned.

West Penn has committed to deploy up to 25,000 smart meters during the grace period.[5] Information obtained through this deployment will be incorporated into the work being performed during the Assessment Period.

Full Deployment – The Companies will be submitting a Deployment Plan in June, 2012 that will set forth their plan for full deployment of smart meters to all customers within the entire post-Allegheny FirstEnergy PA Footprint.

4.0 Budget and Cost Recovery

The SMIP Plan (at page 1) indicates that the total estimated cost of the project during the Assessment Period would be approximately $29.5 million. However, this was a preliminary estimate provided from benchmark data prior to issuance and award of a Management Consulting RFP that yielded hourly rates that were higher than originally anticipated. This factor, as well as certain unexpected, but necessary additional tasks, has increased this estimate, which will be reflected in the Companies' next update to their respective SMT-C riders, which are discussed below.

The Companies each submitted a cost recovery mechanism as part of the SMIP Plan, which was approved by a Commission order entered June 9, 2010. Costs are currently being recovered through each Company's Smart Meter Technologies Charge ("SMT-C") Rider and rates billed to customers under the provisions of those cost recovery riders. Consistent with 66 Pa. C..S. § 1307(e), the Companies will file reconciliations of revenues billed and expenses incurred under their respective

5 Petition of West Penn Power Company d/b/a Allegheny Power for Expedited Approval of its Smart Meter Technology and Installation Plan, Docket No. M-2009-2123951, Appendix A (October 19, 2010).

SMT-C Riders for the SMT-C Reconciliation Year ended June 30, 2011 by July 29, 2011, with tariff supplements (to be effective January 1, 2012) and support for such changes submitted by August 1, 2011.

5.0 Conclusion

The Companies thank the Commission for the opportunity to update it on the Companies progress towards the development of a smart meter solution for the Companies' Pennsylvania Footprint. Should the Commission have any questions about the content of this Report, or need any additional information, please contact:

Mr. Dana Parshall
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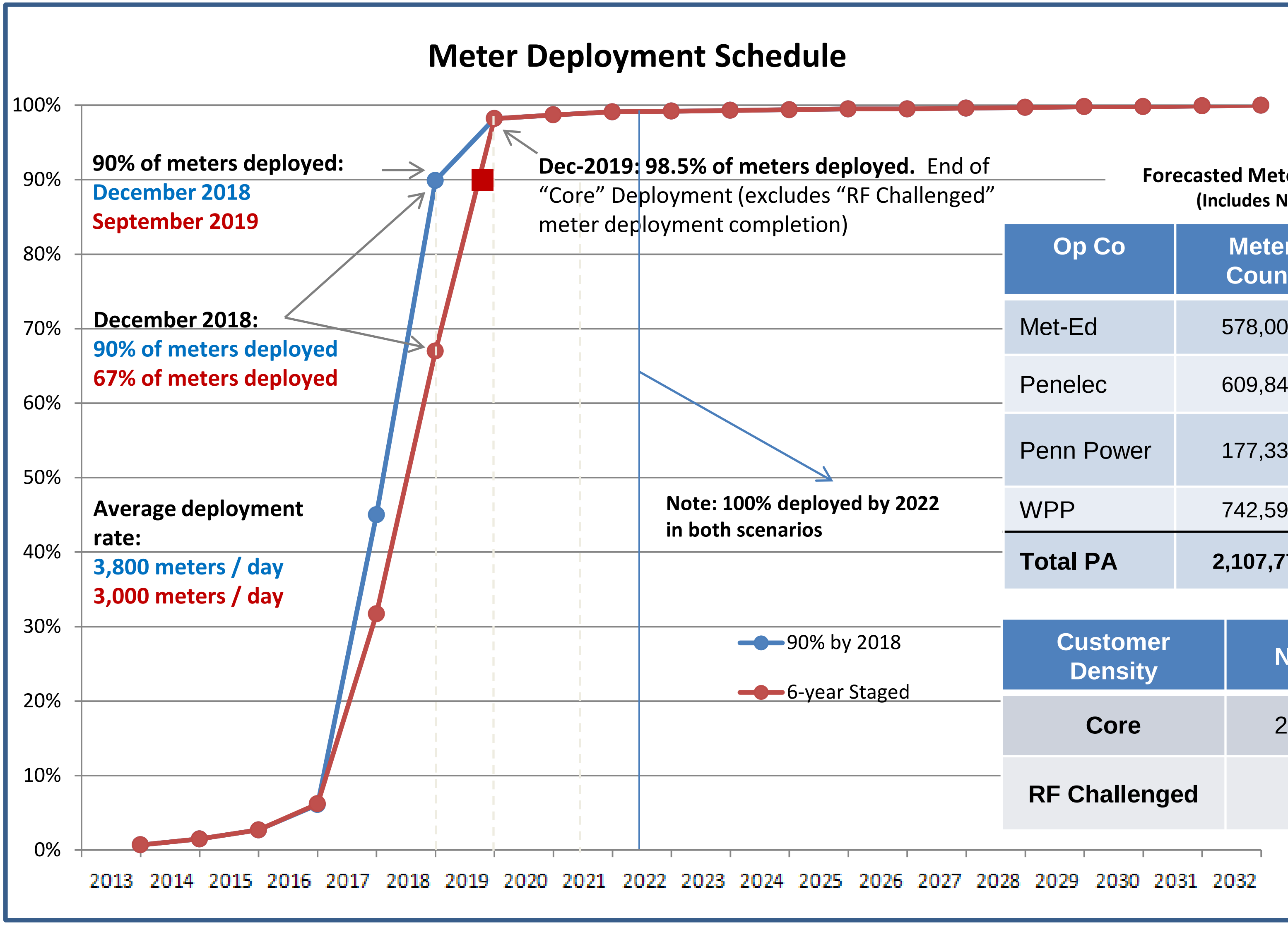
parshalld@firstenergycorp.com

Respectfully submitted,

Mr. Dana Parshall

Exhibit DWI-1

Exhibit DWI-1
Smart Meter Deployment Timeline – 2014 to 2019



Forecasted Meter Distribution (2032)
(Includes New Construction)

Op Co	Meter Count	Distribution of Meters
Met-Ed	578,005	28%
Penelec	609,844	29%
Penn Power	177,335	8%
WPP	742,591	35%
Total PA	**2,107,775**	**100%**

Customer Density	Number of Meters
Core	2,076,159 (98.5%)
RF Challenged	31,616 (1.5%)

Exhibit DWI-2

Exhibit DWI-2

Response of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company ("The Companies") to Sub-Hourly Metering Issues Identified by the Pennsylvania Public Utility Commission in *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company for Approval of Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123950

1. What are the capabilities and limitations of proposed smart meters to measure and record sub-hourly usage?

To meet the requirements of Pennsylvania Act 129, the Companies will deploy smart meters which will be able to measure and record sub-hourly usage in 15-minute increments. Each Company intends to have hourly readings recorded and transmitted to the Company at a minimum of once a day for billing and web presentation. Web presentation to customers would occur from 24 – 48 hours after transmission. The deployed smart meters will have the capability to stream current consumption values in near-real time via a protocol like Smart Energy Profile 2.0 compliant Zigbee RF signal.

2. What are the capabilities and limitations of proposed smart meter communication and data storage systems to transmit and store sub-hourly usage information?

The Companies' smart meter communication and meter data management system ("MDMS") will be designed to transmit and store hourly data. The system will be capable of collecting and storing data in 15-minute intervals and transmitting data in hourly intervals.

3. What are the sub-hourly PJM requirements for participation in ancillary service markets?

PJM Manual 11 "Energy & Ancillary Services Market Operations" Revision 45 Effective Date: June 23, 2010 describes Demand Resources (Section 4.2.9) metering-information requirements. Demand Resources providing Synchronized Reserve are required to provide metering information at no less frequently than a one-minute scan surrounding a synchronized reserve event. Demand resources providing Day-ahead Scheduling Reserve are required to provide telemetry that is capable of providing metering information at no less than a one-minute scan rate.

4. What are each Company's incremental smart meter, communication, data storage, and data sharing costs associated with these sub-hourly requirements for ancillary services?

The Companies' smart meter communication and data storage systems will not have the ability to provide information in one-minute intervals, which is required for the provision of ancillary services, nor are the Companies aware of any AMI system that is currently able to provide information on that basis. The Companies are not able to determine the incremental smart meter, communication, data storage and data sharing costs associated with sub-hourly requirements for ancillary services.

5. What are the incremental equipment and installation costs of pulse data recorders used to measure sub-hourly meter data?

The Companies do not have this information because the Companies do not provide pulse data recorders. Currently, the Companies would provide an auxiliary contact to its existing meter for a customer desiring to install a pulse data recorder used to measure sub-hourly data, and the customer would then supply its own metering.

6. Is a pulse data recorder attached to a Company's meter sufficiently accurate for use by PJM in its ancillary markets, or is redundant metering required to meet PJM standards?

The Companies do not install or operate pulse data recorders and, therefore, does not have the information required to comment on their accuracy. The Companies believe that "additional" metering would be required to meet PJM standards; however, the Companies would not characterize this additional meter as "redundant" because it would be serving a purpose different from that of the Companies' deployed smart meters.

7. What are the additional customer costs associated with (1) transferring pulse meter information from the meter to inside the customer's premise, (2) processing this data into a usable format, (3) communicating the data to a third party or PJM?

The Companies can only provide the costs for providing the auxiliary contacts upon a customer request. Each Company typically would charge $1,200 to $1,500 to install the auxiliary contacts needed to transfer the pulse meter information, depending on customer location, access and other factors. The Companies do not provide the specific services described in this question and are not aware of the additional costs to process and communicate the data to third parties or PJM.

8. To the extent a customer requests sub-hourly data, what, if any, cost recovery charge is appropriate. For example, would it be appropriate to have a customer charge that varies with the level of sub-hourly metering requested, and, if so, what would those sub-hourly metering charges be?

The answer to this question varies depending on the model. Under the current approach where a customer utilizes auxiliary contacts in the meter to pull sub-hourly data for its internal use, no cost recovery is required as the customer is responsible for equipment necessary for recording and analyzing the sub-hourly metering data. Each Company will charge the customer a fee to cover parts and labor associated with the installation of the auxiliary contacts as described in the response to Question 7 above.

In the case where a customer will be receiving sub-hourly metering information through the Zigbee chip directly from the smart meter, the customer will need to purchase an In Home Display device to capture the data. Cost recovery may be required for any network or meter configuration required to activate the chip and any associated incremental labor required to enable this functionality.

STATEMENT NO. 3

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
Docket No.

PENNSYLVANIA ELECTRIC COMPANY
Docket No.

PENNSYLVANIA POWER COMPANY
Docket No.

WEST PENN POWER COMPANY
Docket No.

SMART METER DEPLOYMENT PLAN

Direct Testimony
of
Kevin A. Klein

List of Topics Addressed

Overview of Smart Meter Requirements and Solution
Solution Validation Stage
Public Cellular Backhaul
System Security
Direct Meter Access and Access to Data

DIRECT TESTIMONY OF KEVIN A. KLEIN

I. Introduction and Purpose of Testimony

Q. Please state your name and business address.

A. My name is Kevin A. Klein. My business address is Two Riverway, Houston, Texas 77056.

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

A. I am employed by IBM Corp. and my role on the FirstEnergy Smart Meter Implementation Plan ("SMIP") project is that of IBM Program Director.

Q. Please summarize your educational background and professional experience.

A. I graduated from the University of Texas at Austin in 1985 with a Bachelor of Science Degree in Mechanical Engineering. I have worked for IBM for approximately 14 years, having started my career out of college at the National Aeronautics and Space Administration ("NASA"). The last position I held at NASA was the Manager of the International Space Station, Safety & Mission Assurance and Program Risk office.

Q. What are your responsibilities on the SMIP project as the IBM Program Director?

A. As the IBM Program Director, I am responsible for providing technical solution and subject matter expertise, managing all work products and deliverables resulting from the IBM contracts to ensure they were of high quality, supervising all IBM project resources to ensure consistent and high quality consulting support to the SMIP team, managing and escalating project issues and risks that impact or threaten the successful completion of the

SMIP Project and providing leadership to SMIP work streams and the client's management team.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory agency?

A. No.

Q. On whose behalf are you testifying and what is the purpose of your testimony?

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (collectively, the "Companies") with respect to certain technical aspects of the Commission's smart meter requirements and the Companies' proposed solution for those requirements. I am supporting the technical solution described in Chapter 3 of the Deployment Plan that was submitted as an exhibit to the Petition filed in this proceeding on December 31, 2012. I will also discuss the recommended use of a public communications backhaul network and describe the Companies' position on system security and access to data. Unless otherwise stated, my testimony applies equally to all four Companies. Further, instead of reiterating portions of the Deployment Plan in my testimony, sections and topics of the plan to which I refer are incorporated into my testimony by reference.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit KAK-1, a graphic depiction of the Companies' smart meter solution recommended in the Deployment Plan, and Exhibit KAK-2, the Deployment Timeline with Estimated Functionality.

II. <u>Overview of Smart Meter Requirements and Solution</u>

Q. What functionality requirements must the Companies' smart meter solution have?

A. The Commission's smart meter Implementation Order set forth the following Act 129 mandatory smart meter functionality requirements:

- The ability to provide bidirectional data communications;
- The ability to record usage data on at least an hourly basis once per day;
- The ability to provide customers with direct access to and use of price and consumption information;
- The ability to provide customers with information on their hourly consumption;
- The ability to enable Time-Of-Use ("TOU") rates and Real-Time Pricing ("RTP") programs; and
- The ability to support the automatic control of the customer's electric consumption.

The Commission also identified the following additional functionalities for consideration by the Companies subject to the Act 129 smart meter deployment requirement:

- The ability to remotely disconnect and reconnect;
- The ability to provide 15 minute or shorter interval data to customers, EGSs, third parties and a regional transmission organization ("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;
- The ability to upgrade these minimum capabilities as technology advances and becomes economically feasible;
- The ability to monitor voltage at each meter and report data in a manner that allows an electric utility to react to the information;
- The ability to remotely re-program the meter;
- The ability to communicate outages and restorations; and
- The ability to support net metering of customer generators.

The Itron solution selected by the Companies for their smart meter deployment will provide all the foregoing functionality required by Act 129 and the Commission Implementation Order as described in Chapter 3 of the Deployment Plan. The Itron meter solution provides a robust design for two-way communication with field devices or Zigbee-enabled in-premise devices throughout the system, utilizing the radio frequency ("RF") mesh communications and Wide Area Network ("WAN") backhaul. This includes the ability to receive and send critical commands and information which include on-demand reads, remote connect/disconnect, energized status (meter ping) and voltage checks.

Q. How does smart meter functionality becomes available over time throughout the Deployment Plan?

A. Automated functionality becomes available as the "backbone" system is constructed and made operational in stages. As backbone is available to support smart meters, functionality is provided to newly installed Itron meters. My Exhibit KAK-2, captioned Deployment Timeline with Estimated Functionality, depicts the progress of functionality.

Q. You indicated that the Companies selected Itron as their meter vendor. Will the Itron meters provide all of the functionality required by Act 129 and the Implementation Order?

A. Yes. A key vendor selection criterion was the vendor's ability to comply with Act 129 requirements and Commission guidance in the Implementation Order. The Commission recognized in the Implementation Order that some smart meter functionality may not be cost-effective to implement and provided EDCs with the option to petition for a waiver of requirements if cost-effectiveness could not be shown. Based upon information known today, the Companies anticipate that the various functionality of the smart meters will be available consistent with the time line set forth in Exhibit KAK-2. Smart meters deployed during Full-Scale Deployment will support all of these functions, as well as remote service switch capability and the capability to determine sub-hourly reads.

Q. In its June 9, 2010 Order at Docket No. M-2009-2123950, the Commission directed the Companies to study several issues associated with sub-hourly metering, conduct a stakeholder meeting, and prepare a cost/benefit analysis. Did the Companies implement the Commission's directive?

A. Yes. Mr. Iorio's Exhibit DWI-2 sets forth the issues identified by the Commission and the Companies' conclusions with respect to each issue following meetings with the parties to the proceedings at Docket No. M-2009-2123950 and other stakeholders. An initial stakeholder meeting was held on August 17, 2011, where the Companies solicited perspectives on sub-hourly metering needs. Generally, the Companies found that there was likely to be relatively low customer interest in sub-hourly data, but that the customers (and vendors) who would use that information desired data as near to real-time as possible.

Following the initial stakeholder meeting, the Companies considered a variety of sub-hourly metering arrangements and the associated costs of network storage, engineering support, hardware/software, and backup systems. In light of the high costs of implementing sub-hourly metering across the entire smart meter system solution for all customers, the Companies concluded that a less costly solution could be through the customers' use of an In-Home Device ("IHD"). Under this arrangement, those customers who desired sub-hourly metering data could easily access that information without requiring a far more expensive smart meter solution across the Companies' systems. I am advised that the Companies held a second stakeholder meeting on February 16, 2012, at which this proposed solution was discussed and received positively by stakeholders.

Q. Mr. Klein, did the Companies analyze the cost of implementing sub-hourly metering for all customers?

A. Yes, that issue was analyzed by examining the work completed on this issue by other companies subject to Act 129 such as PECO and DQE and assuming sub-hourly metering was made available for all of the Companies' customers. Given the Companies' size, and making the same assumptions, the costs would be unreasonable and cost prohibitive after factoring in cost elements such as network storage, engineering support, the communications network, hardware/software upgrades and backup systems.

Q. Please describe the Companies' solution to the smart meter requirements.

A. The major components of the Companies' technology solution are the Smart Meter, the Collectors, the Head End, the Meter Data Management System ("MDMS") and a Communications Network. Other related components that integrate into the solution are the customers' Home Area Network ("HAN"), Company legacy systems and the Customer Information System ("CIS") called Systems Applications and Products ("SAP") software. See attached Exhibit KAK-1 for a graphic depiction of how these components interface.

The smart meter sends and receives information through the Communications Network. The LAN conveys meter data to collectors. The WAN is the communications infrastructure that interconnects the collectors with the Head End. Based on RFP responses and lab testing results, Itron has been selected as the vendor for the Meters, Head End and MDMS. In addition to these general vendor selection factors, Itron also demonstrated a high level of support throughout testing and provided meters for the West Penn Energy Efficiency Rewards Program. The Head End serves as the gateway for communications. It communicates with aggregations of smart meters, command routers and customer-owned HAN devices. The Head End also integrates with the MDMS which serves as the primary repository of all measurement, status and event data collected from the smart meters. The MDMS reviews unvalidated data from smart meters, compares it to expected values and flags the data that fails validation. This process is referred to as Validation, Estimation and Editing ("VEE"). The MDMS ensures that validated smart meter data is available for customer billing and operations. The MDMS is also the gateway for communications with smart meters for data requests, commands, alert messages from and to other information systems such as the Customer Information System, Work and Asset Management and Work Force Management. It includes other functions such as processing remote service orders, status data and event data. It is necessary to upgrade the SAP system to meet the requirements/needs of the Deployment Plan. The Companies use SAP enterprise software for a significant portion of its Customer Management, Billing and data management needs.

Q. You mentioned that the Communications Network was a major element of the smart meter solution. Please describe the network.

A. The Communications Network utilizes what we refer to as a "mesh" approach, rather than a private point-to-point network system. The private point-to-point approach requires the construction of towers to "talk" to the smart meters, while a mesh network relies on radio-frequency ("RF") to form network routes that connect the meters to communications devices and the collectors, creating a Local Area Network ("LAN"). The LAN connection uses a proprietary communications protocol unique to the vendor. A meter communicates to a string of meters and this data is then picked up at the collector for transport to the backend systems over the WAN using a standard protocol for "backhaul" services. The Companies have verified that the Itron meters are compatible with the Itron mesh network design.

Q. Why did the Companies select the mesh network rather than a private point-to-point network?

A. Over a large service territory such as that served by the Companies, many communications towers would have to be constructed if a private point-to-point network approach was adopted. If a point-to-point tower fails, communication is only maintained if the system is built with overlapping tower coverage, which increases costs. In a mesh configuration, the meters can reconfigure communications routes in the event of an equipment failure. The mesh network has innate failovers to keep the communication network working; point-to-point does not. Private point-to-point systems can operate well in a compact urban service territory; however, the Companies' service territory is too vast and, therefore, it would be too costly to employ a private point-to-point system.

Q. What general types of backhaul services did the Companies consider?

A. The Companies evaluated both the public backhaul solution provided by cellular vendors such as Verizon and AT&T, as well as the construction of a private communications backhaul system, and concluded that the public backhaul solution was preferable and less costly for customers.

Q. Why is the public backhaul solution preferable?

A. Using a public cellular network for backhaul was clearly the most cost effective option and the option that will allow the Companies to complete the installation of meters sooner than would otherwise be possible if a private backhaul system had to be designed and constructed. Public network vendors incur the capital costs to design and construct the network. They also provide their own network support and monitoring. The public backhaul solution has lower initial and ongoing costs compared to a private network, lower technology risk and lower vendor stability risk. We estimated that a private network would be 9.8 to 16.5 times more expensive than a public network. The public network also meets compliance requirements as well as industry and security standards.

The Companies selected AT&T and Verizon as their public backhaul carriers. These companies continuously monitor these types of standards and have the expertise to maintain their networks using the highest standards and protocols. The public network also provides excellent service territory coverage in most areas. In 2013, between Verizon and AT&T, the public network will cover over 95 percent of the Companies' service territories. The Companies estimate that within the remaining 5 percent of the service territories, approximately 1.5 percent or less of all meter installations will be "RF challenged" in 2019. Because the public carriers are continuing to build out their networks, the Companies will address these RF challenged meter installations at the end of the meter deployment period, with the expectation that cellular coverage will be available by that time. If, however, public network coverage is still an issue in a particular area at the time of deployment, the Companies will evaluate other solutions, such as satellite coverage, in order to provide a communications solution for these RF challenged meters.

Q. Have other utilities elected to use a public backhaul system?

A. Yes. Generally, unless a utility's service territory is relatively compact, most utilities select the public backhaul solution for the reasons I just discussed. Notably, the other major companies that the team visited or spoke with, Oncor, Southern California Edison, San Diego Gas and Electric, Pepco Holdings, Inc., Florida Power & Light, and Duke Energy -- all of which have each deployed over a million smart meters -- opted for using public networks, typically Verizon and AT&T. The majority of utilities with major smart meter deployments has wisely chosen use of a public network backhaul system and, in my opinion, so too have the Companies.

III. Solution Validation Stage

Q. Mr. Klein, are you familiar with the Solution Validation Stage being proposed in the Deployment Plan?

A. Yes, I am.

Q. In your view, is the Solution Validation Stage a necessary step in the deployment of the smart meter solution?

A. Yes. The Solution Validation Stage will be time well spent to test the smart meter solution devised by the Companies on a larger scale than lab or similar limited test environments would otherwise permit. This large scale field validation is certain to provide a wealth of information that will allow the Companies to correct problems before full-scale deployment, thus reducing the overall costs and risks of deployment and minimizing customer frustration as the Companies try to find solutions to problems encountered during this period.

IV. Customer and System Security

Q. Does the Deployment Plan address customer information and system security?

A. Most definitely. The smart meter solution included in the Deployment Plan incorporates ongoing measures by the Companies to protect customer information and systems as well as new and evolving protocols for cyber-security.

Q. Please explain.

A. Security on the smart meter system, including the smart meter architecture and the protection of data end to end, has been a priority throughout this project. Information must cross a number of domains and it is important for trust relationships to be established so interaction across these domains is secure. The Companies' cyber-security plan will ensure that all systems and hardware are fully secure and data is protected using nationally recognized protocols and standards. Where vendors are involved, they will be required by Service Level Agreements to adhere to Company and National Institute of Standards and Technology ("NIST") security standards. The smart meter network design will be securable to protect customer data. Company systems are regularly evaluated for access appropriateness and adequate cyber-security controls in accordance with the Companies' standards developed from ISO 17799 and ISO 27001/2. All smart meter related data communication over the network will be encrypted. The data exchanged between the collectors and the smart meter will be accompanied by authentication in accordance with utility cyber-security best practices. Vendors will implement internal security measures to ensure proper authentication within their networks.

Communications between collectors and Head End will be encrypted at all points of ingress and egress. The Companies will implement hardware, software and procedural mechanisms that record and examine activity in systems that contain sensitive information. The actions of users that have privileged access to operating systems, databases, key network devices, and the security devices will be monitored. Using internal and external audit processes, the Companies will regularly monitor and correct security issues.

Q. What specific Company security practices are involved?

A. The Companies employ technologies such as log management, monitoring and alerting to detect attempted intrusions, operational issues and security violations. Mitigation controls automatically react when violations or suspected violations occur. Incident response and disaster recovery controls are tested and prepared to recover systems that have failed or been compromised. Policies and procedures for cyber-security are being followed to protect critical infrastructure. Personnel with access to cyber assets are required to complete cyber-security awareness training annually. Communications take place between internal IT teams and external peers to provide early warning of threats and adequate controls for new and emerging threats. The smart meter solution will include multiple security zones with secured applications and restricted access.

Q. How will the Companies protect the privacy of customer information?

A. Privacy protection is an important issue due to the personal interval data introduced and tracked through advanced meter infrastructure, as well as greater accessibility to usage data and load profile information. The Companies currently manage the security of customer data such as names, account numbers and addresses. Customer consent is required to release data to third parties. This practice will not change. The Companies will not transport or proliferate customer names, account numbers or addresses through the advanced metering infrastructure network, only interval data. Current data protection processes will be followed from the outset of the Deployment Plan to prevent confidential data leakage.

Q. What privacy and security standards will the Companies follow?

A. The Companies follow several NIST security standards and guidelines regarding advanced metering infrastructure. Privacy policies are published on the Companies' website. On implementation of the Deployment Plan, any breaches or misuse of data will be identified using these policies and procedures. The Companies do not sell, share or otherwise make available information collected off the website.

V. <u>Direct Meter Access and Access to Data by Third Parties</u>

Q. Is access to meters and usage data a required element of the smart meter solution?

A. Yes, it is. The Companies are required by Act 129 and the Commission's Implementation Order to provide customers direct access to price and consumption information; and with customer consent, they must make available direct meter access and access to customer data to third parties, including electric generation suppliers ("EGSs") and providers of conservation and load management services. I am advised that the Commission requires that smart meters have the ability to collect 15-minute interval data for customers, EGSs, third parties and the RTO, in this case PJM, on a daily basis, consistent with the data availability, transfer and security standards adopted by the applicable RTO. Customers and designated third parties are to receive price and meter data in a timely manner. The Companies are required by the Commission to provide customers and designated third parties access to validated bill quality consumption data within 48 hours of the meter read and smart meters are to be capable of communicating raw data on at least a near real-time basis to IHDs installed by the customers or their agent.

Q. Are these capabilities provided for in the smart meter solution?

A. Yes. The proposed system architecture will provide all of these capabilities. These capabilities are more fully discussed in Chapter 3 of the Deployment Plan.

Q. Mr. Klein, does this complete your direct testimony?

A. Yes, it does.

Exhibit KAK-1

Exhibit KAK-1
Smart Meter Solution

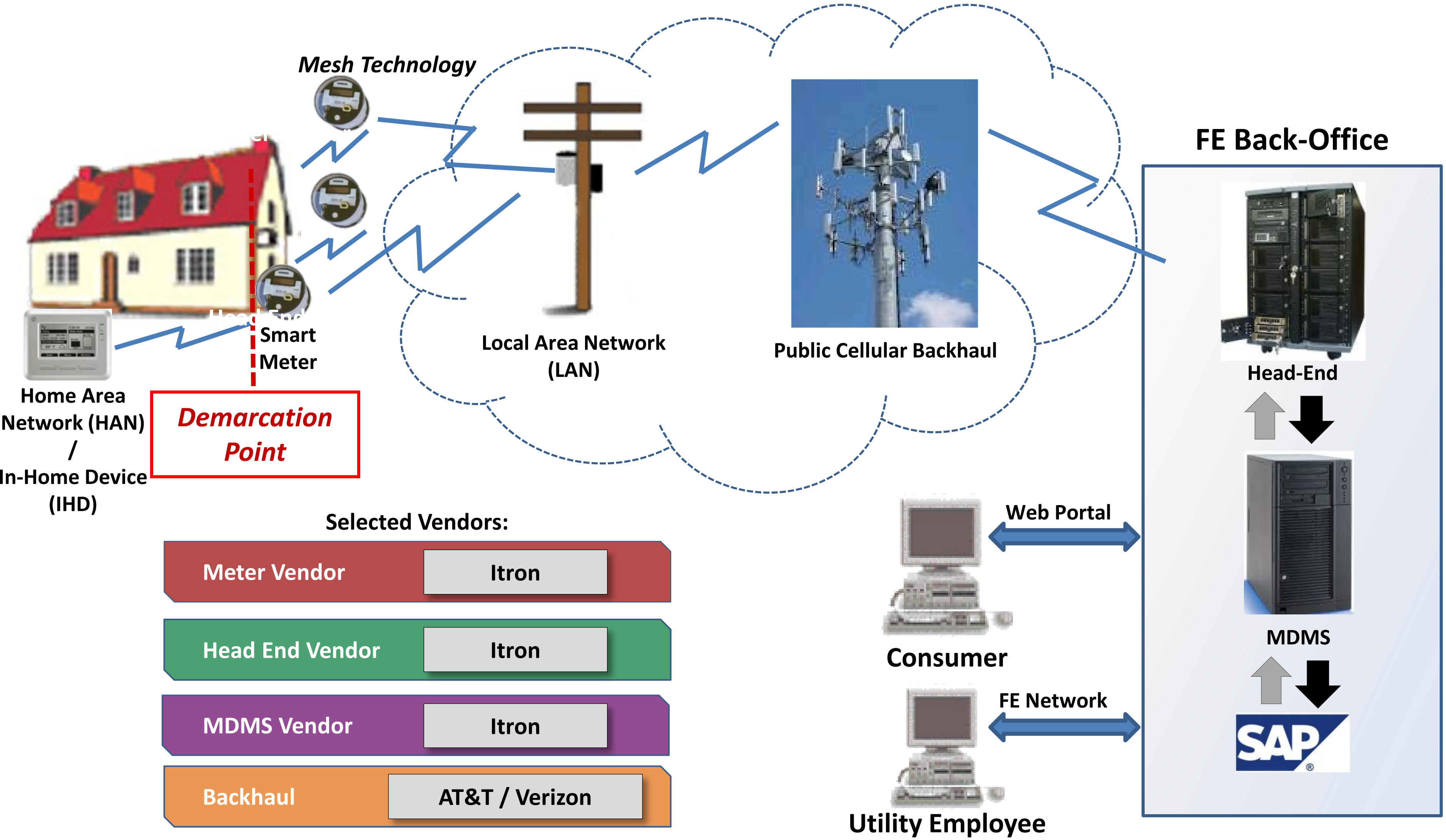
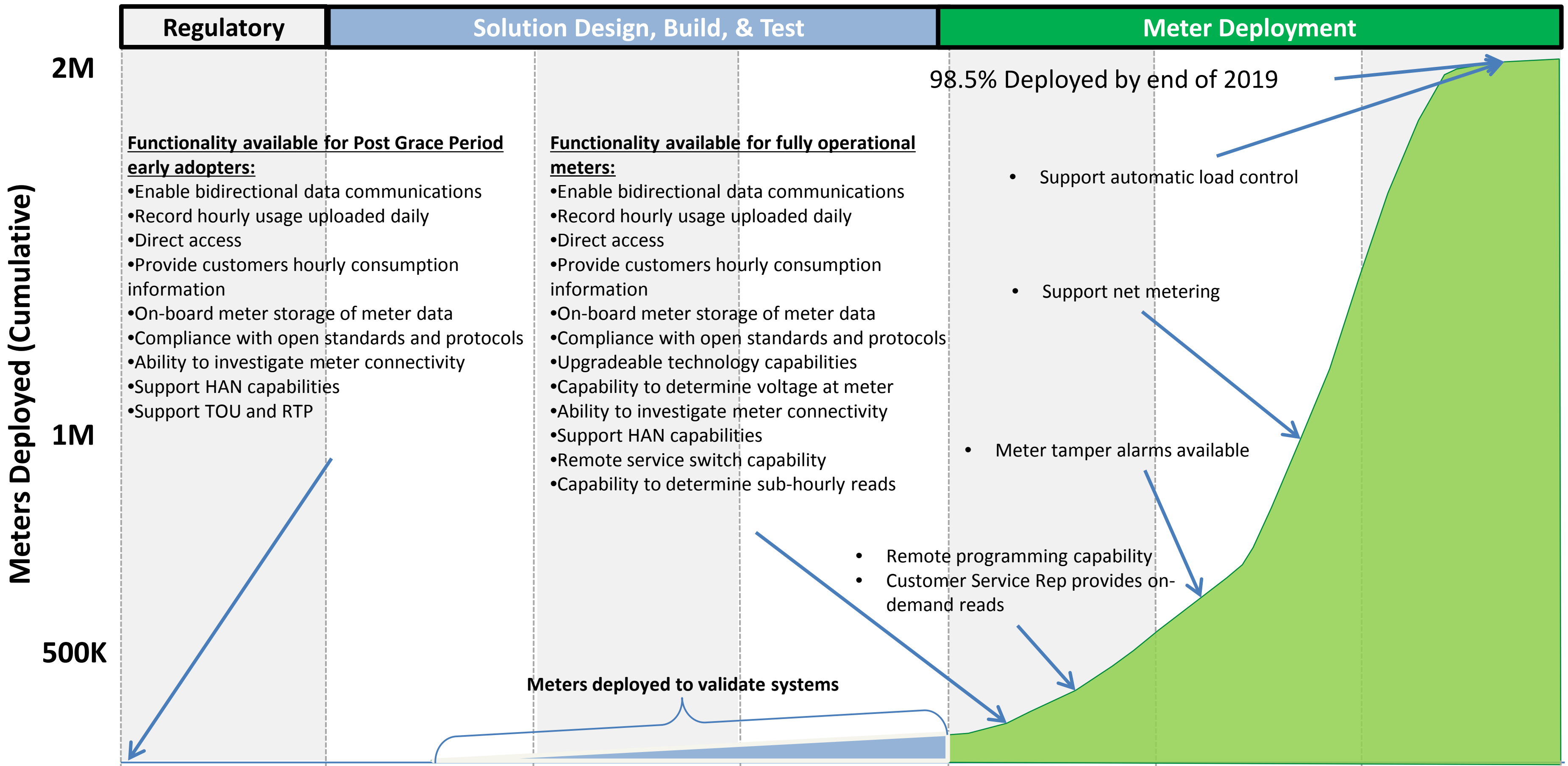


Exhibit KAK-2

Exhibit KAK-2
Smart Meter Deployment Timeline and Estimated Functionality



	2013	2014	2015	2016	2017	2018	2019
PGP*	14K	28K	42K	56K	70K	84K	98K
Staged	-	5K	15K	60K	600K	1.4M	2M

Meters Deployed (Cumulative)

*Includes early adopters and new construction. Functionality for new construction will not be available until network is available in the area.

STATEMENT NO. 4

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
Docket No.

PENNSYLVANIA ELECTRIC COMPANY
Docket No.

PENNSYLVANIA POWER COMPANY
Docket No.

WEST PENN POWER COMPANY
Docket No.

SMART METER DEPLOYMENT PLAN

Direct Testimony
of
George L. Fitzpatrick

List of Topics Addressed

Financial Implications of Deployment Schedule
Major Cost Components of the Deployment Plan
Potential Cost Savings
Communications, Training and Change Management Plans

DIRECT TESTIMONY OF GEORGE L. FITZPATRICK

I. Introduction and Purpose of Testimony

Q. Please state your name and business address.

A. My name is George L. Fitzpatrick and my business address is Black & Veatch Corporation, 888 Veteran's Highway, Suite 120, Hauppauge, New York 11788.

Q. Please describe your current position with Black & Veatch.

A. I hold the position of Executive Managing Director within the Management Consulting division of Black & Veatch. My current responsibilities include leading the Demand Side Management/Energy Efficiency ("DSM/EE") practice and the Regulatory Litigation Support practice within the Management Consulting Division. I am also designated as a Subject Matter Specialist in a number of areas related to our electric and gas utility consulting practice.

Q. Please describe your professional experience relevant to the testimony you are now giving.

A. My professional experience includes over 35 years within utility management and electric/gas technical and management consulting fields. My areas of expertise include econometric and statistical analysis for energy and peak forecasting, load research, integrated resource planning, DSM/EE assessment, program design, implementation and evaluation, as well as generating plant life cycle economics, operating costs and performance modeling and overall utility investment prudence analysis. Over the last two and a half years I have been heavily involved as a member of the Smart Meter

Implementation Plan team ("SMIP Team") responsible for the development of the Deployment Plan that is the subject of this proceeding. My focus has been on regulatory and stakeholder communications, customer, market and load research, and lifecycle benefit/cost model development and analyses.

I have testified extensively throughout the United States before state regulatory commissions. Areas in which I have provided testimony include:

- Integrated Resource Planning
- Electric and Gas DSM/EE Program Assessment, Implementation and Evaluation
- Lifecycle economic evaluation of utility investments
- Econometric/statistical-based Load and Energy Forecasting
- Other Econometric and Statistical Studies on Utility-related issues
- Weather Normalization Studies
- Strategic Planning
- Load Research Program Sample Design, Implementation and Analysis
- Rate Design
- Cost of Service Studies
- Renewable Program Evaluation
- Performance Standard design and statistical construction.

A complete description of my professional background is attached to my testimony as Exhibit GLF-1.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") (collectively, "PA Companies") and West Penn Power Company ("West Penn") (collectively, with the PA Companies, "Companies"). Unless otherwise stated, my testimony applies equally to all four Companies. Further, rather than reiterating in my testimony the content of the Deployment Plan ("Plan") that was attached to the Joint

Petition filed herein, sections of the Plan to which I refer are fully incorporated into my testimony by reference.

Q. Are there any exhibits included with your testimony?

A. Yes, the following four exhibits are attached to my testimony:

- Exhibit GLF-1 - Resume of George L. Fitzpatrick
- Exhibit GLF-2 - Summary of Total Costs, Cost Savings and Net Costs
- Exhibit GLF-3 - Summary of Costs by Categories
- Exhibit GLF-4 - Summary of Operational Cost Saving Categories

Q. Were your testimony and supporting exhibits developed by you or under your direction and control?

A. Yes.

Q. What is the purpose of your testimony?

A. I am supporting Chapters 4 and 6 of the Deployment Plan. More specifically, the purpose of my testimony is to explain and support (i) the financial implications of the Smart Meter Deployment Schedule being proposed in this proceeding; (ii) the major cost components of the Deployment Plan; (iii) the estimated potential cost savings that may arise from the installation of smart meter technology; (iv) how such savings will be tracked and verified; and (v) the Companies' interaction and expected interaction with customers, employees and other interested parties.

II. Deployment Schedule and Other Analyses

Q. Please describe the deployment schedule that the Companies are proposing in this proceeding.

A. In their 2009 Smart Meter Implementation Plan ("SMIP"), the PA Companies anticipated deployment of most smart meters by 2022. After 30 months of evaluation of smart meter costs, benefits, technologies, and risks, the Companies are proposing a three stage deployment schedule, the last two of which will have approximately 98.5% of all smart meters deployed between January 1, 2014 and December 31, 2019 ("Deployment Period"), assuming the Deployment Plan is approved by September 30, 2013 ("2019 Recommended Scenario"). The first stage, the Post-Grace Period ("PGP") Stage, involves the installation of smart meters for new construction and customers requesting smart meters prior to their scheduled installation date. The second stage, referred to as the Solution Validation Stage, involves the construction of a fully integrated smart meter network that will be constructed in the Penn Power service territory. This stage will start sometime during the last quarter of 2013 and is expected to continue through the first quarter of 2017. During this period, approximately 60,000 meters will be installed and tested in a "mini" version of the smart meter network that will ultimately be built throughout the FirstEnergy Pennsylvania footprint once all encountered problems are resolved on the "mini-system". Only after it is determined that all deployment issues arising on this "mini-system" have been corrected will the next stage start. This stage, referred to as the Full-Scale Deployment Stage, will incorporate the deployment of all remaining meters (approximately 2 million) by the end of 2022, with 98.5 percent installed by the end of 2019.

Q. Why can't all meters be installed by the end of 2019?

A. As Companies Witness Klein explains in more detail in his testimony, it is expected that approximately 1.5 percent of the Companies' meters will involve installations in areas that are difficult to access or difficult to incorporate into the basic smart meter infrastructure. Examples of these locations would be installations at remote hunting cabins or in areas where communications with the smart meters would be impaired by poor access to Radio Frequency ("RF")-based communications from publicly accessible cellular communications systems. The Companies will address these remaining meters last, so as not to slow down the build-out of the infrastructure. In addition, it is hoped that, during the interim, any potential communication issues could be resolved through technological improvements, thus avoiding the need to incorporate significantly more expensive communication solutions, such as satellite transmissions, when integrating such remote locations into the overall infrastructure.

Q. Is the deployment schedule being proposed in this case the only scenario that was contemplated by the Companies?

A. No. The Companies looked at a number of scenarios. Pursuant to the settlement agreement approved in Docket No. M-2009-2123951, West Penn committed to assess the costs of deploying 90 percent of all smart meters by the end of 2018. The Companies used this as the base case for all of the Companies and then compared alternate deployment scenarios to this base case scenario. The Companies then selected for further analysis two additional scenarios that they believed provided the opportunity to best balance the costs of deployment and the potential risks associated with the various deployment scenarios.

Q. Please generally describe the other alternatives.

A. In addition to the West Penn settlement scenario of 90 percent deployment by the end of 2018, the SMIP Team also evaluated the 2019 Recommended Scenario and a similar scenario assuming 98.5 percent deployment by the end of 2020. Longer deployment scenarios were also assessed, but were dismissed, partly because the Commission encouraged the PA Companies to try to accelerate the deployment schedule from 2022, which was originally projected as the substantial completion date in their 2009 SMIP filing, and partly because these schedules were more costly due to potential price increases, the need for longer deployment-related contracts, slower realization of cost savings, and other unknown risks.

Q. What were the results of the 2018, 2019 and 2020 scenarios?

A. A summary of estimated costs and potential savings under each of these scenarios is set forth on attached Exhibit GLF-2, Summary of Total Costs, Cost Savings and Net Costs, both on a nominal and net present value ("NPV") basis. While not significant to the overall analysis, it should be noted that the 2018 scenario is based on an assumption that 90 percent of the smart meters are installed by the end of 2018, with 98.5 percent being installed by the end of 2019, while the other two scenarios are based on 98.5 percent of all installations being completed by the end of the designated years.

Q. What were the considerations that ultimately led to the selection of the 2019 Recommended Scenario?

A. The costs of each deployment schedule were obviously a significant factor. However, I have been performing such comparative lifecycle economic analyses on utility investments for clients since 1984. Based upon my experience to date, adhering strictly to the "lowest cost" scenario without also having an understanding of the risk profile of each scenario is not a prudent approach. Therefore, the Companies also evaluated various risks surrounding each of the deployment schedules. Although the 2018 scenario looks to be slightly less costly than the 2019 Recommended Scenario, the Companies believe that the 2018 scenario contains more risk from a meter deployment standpoint. In order to achieve the 2018 scenario, approximately 3800 meters per day would have to be installed. Given the nature of the four Companies' service territories, this installation rate is very aggressive. Under the 2019 Recommended Scenario, an average of 3,000 meters are assumed to be installed per day, which is much more realistic and would be much more likely to be at a pace that should avoid a number of installation problems and higher cost risk. The bottom line is that the 2019 Recommended Scenario is the one that the Companies consider to be the most likely to achieve the ultimate goal—the deployment of a comprehensive, well-tested smart meter system in a reasonable timeframe at the lowest cost after factoring in risks.

Q. Could the proposed deployment schedule be shortened?

A. While it probably could, I do not recommend it – at least initially. Throughout the entire Grace Period, the Companies have adopted a risk reducing, measured approach in which they gather as much information as possible and trouble shoot as many problems in a controlled environment as they can. This was evident by the use of their test lab and RFI-RFP processes, all of which are discussed by Companies Witness Iorio. This approach identified many issues that may otherwise have gone undetected or, alternatively, would have been detected much later in the process, thus requiring costly “workarounds.” This experience also influenced the Companies’ decision to start with the Solution Validation Stage that builds-out and tests an end-to-end solution in an environment that will simulate the most challenging features that may be found in each of the Companies’ service territories. Although this approach will take approximately three years to complete, I believe that it is prudent, given the potential downside. Having said this, however, it should be kept in mind that the Companies cannot anticipate all potential problems and the timeframes in which these problems would be corrected.

Q. What do you mean by “potential downside”?

A. Fixing emerging problems as you build-out a full smart meter system can be extremely expensive. It also creates customer frustration, which can lead to negative customer feelings toward smart meters. By resolving these problems in a more contained and controlled environment, these frustrations and potential costly “workarounds” are kept to a minimum.

Q. In your opinion, is the 2019 Recommended Scenario the optimal deployment schedule for the Companies and their customers?

A. Yes, it is.

Q. You indicated that West Penn committed to perform an analysis of 90 percent of all meters installed by 2018. Did West Penn commit to perform any other analyses?

A. Yes. Pursuant to that same settlement agreement approved in Docket No. M-2009-2123951, West Penn agreed to perform the following analyses:

1. A benchmark comparison of the costs of its revised, proposed network development and installation plan to those approved for several comparable companies;
2. An updated analysis similar to that submitted by Nevada Power to the Nevada Commission at Docket No. 09-07003;
3. An estimate of improvements in West Penn's distribution system reliability in terms of cost savings, such as increased efficiency in responding to outages;
4. An estimate of savings in supply costs, including capacity and energy costs;
5. An estimate of the likely participation and electricity usage reductions of the Company's customers in response to the programs and rate offerings enabled by smart meters; and
6. An evaluation of the merits of deploying In-Home Devices ("IHDs") in conjunction with the deployment of smart meters; but agreeing not to deploy, prior to May 31, 2013, any such IHDs in support of West Penn's Energy Efficiency and Conservation ("EE&C") Plan that was then pending before the Commission for consideration at Docket No. M-2009-2093218.

Q. Did the Companies perform the benchmark comparison?

A. Yes. As I discuss later in my testimony, the Companies performed a benchmark comparison of costs per meter for other comparable smart meter installations made by other utilities.

Q. Did the Companies perform an updated analysis similar to the Nevada Power study?

A. Yes. As discussed in Chapter 4, the Companies performed an in-depth financial analysis of the recommended solutions included in the Deployment Plan. This analysis incorporated numerous variables, including those used as part of the Nevada Power study.

Q. Did the Companies estimate their improvements in system reliability?

A. No. Such an analysis incorporates numerous variables, many of which cannot be known with any certainty until baselines are established and a history is created after smart meters are installed. Further, if there are any system reliability improvements to be had as a result of smart meters, the smart meter technology would have to be integrated with the Companies' outage management system. This functionality is not currently being considered in the near term. Although this analysis was not performed, Chapter 4 does address other potential savings that may arise as a result of fewer truck rolls and less personnel needed for field activities.

Q. Did the Companies estimate potential savings in supply costs?

A. No. Again, such an estimate could not be made with any confidence, given all of the unknown variables, including forward prices in 2018 and beyond – the period during which a sufficient number of smart meters would be installed – to make such an estimate meaningful.

Q. Did the Companies estimate likely participation in smart meter programs?

A. Yes. As I discuss later in my testimony, the SMIP team performed market research through customer surveys in the PA Companies' service territories. This research solicited approximately 15,700 customers, with 3,700 responses, yielding an overall survey response confidence level exceeding 90 percent. Among the information solicited were (i) customer familiarity with smart meter technology; (ii) their familiarity with smart meter functionality; (iii) the customers' priority ranking of such functionality; and (iv) their overall awareness of electricity use. These results were shared with the Office of Consumer Advocate and several other parties interested in low income and vulnerable customer load and market research, which I also discuss later in my testimony.

Q. What were the results of this research?

A. In general, the customers responding to the surveys rated themselves highly on their awareness of their electricity use. Further, these customers indicated that they have tried, and will continue to try, to reduce electricity use. Over two-thirds of these customers indicated that time of use rates, enabled by smart meters, could be useful in helping them to reduce their electric bills. The responses received did not vary significantly among the Companies' respective customer bases.

Q. Was similar research performed in West Penn's service territory?

A. No. Given the results obtained from the other Companies' service territories and the fact that there was not a significant difference in responses among the PA Companies involved in the surveys, the Companies saw no need to incur the additional costs to expand the scope of the survey. Further, none of the parties with whom the results were shared requested such an expansion of the scope.

Q. Did the Companies evaluate the merits of installing IHDs in conjunction with the deployment of smart meters?

A. Yes. The Companies concluded that IHD technology is something that lends itself to the competitive market and decided against including these devices as part of the smart meter solution offered by the Companies. This decision was vetted through the stakeholder process where it was met with general agreement of the participants.

III. Project Costs

Q. How were the costs of the deployment plan determined?

A. The Companies estimated the costs of this project over a 20 year period, starting at the beginning of the Post-Grace Period in 2013 and ending in 2032.

Q. What is the estimated total cost of the Deployment Plan over this 20 year period?

A. The total cost of the Deployment Plan over the 20-year period in nominal dollars is estimated to be $1.258 billion and, on a net present value basis, approximately $694 million. The following are the major cost components of the smart meter project: (i) Meter and Local Area Network ("LAN"); (ii) Network and Network Management; (iii) Information Technology ("IT"); (iv) Systems Integration; (v) Business Staffing; (vi) Communications and Change Management; and (vii) Project Management. The estimated costs for each of these cost components under the 2019 Recommended Scenario are summarized on attached Exhibit GLF-3, Summary of Costs by Categories. A more detailed discussion of these costs can also be found in Chapter 4 of the Deployment Plan.

Q. How much of the project costs will be spent during the Deployment Period?

A. Approximately $752 million of the $1.258 billion will be spent during the Deployment Period. The remaining costs include approximately $318 million for an "IT Refresh"; approximately $85 million for meter replacement during the life of the project; approximately $12 million for public backhaul services provided by AT&T and Verizon; approximately $74 million for incremental staffing needs, which are discussed in Chapter 4 of the Deployment Plan; approximately $3 million for program management, also discussed in Chapter 4; and approximately $11 million for change management, including training and internal and external communications, which I discuss later in my testimony. It should be kept in mind, however, that these are estimates for purposes of financial analysis only and are based on information known today and prudent decision-making given the Plan's objectives. These costs are clearly subject to change, especially as we get to the out years of the project. As Companies Witness Valdes explains in his testimony, the Companies have included a reconciliation mechanism in their cost recovery rider so as to only reflect actual costs incurred.

Q. What do you mean by an "IT Refresh"?

A. The financial analyses assumed that the estimated useful lives of the IT hardware and software are 5 and 7 years, respectively. Because this analysis spans 20 years, all of the hardware and software will have to be replaced at least once during the life cycle of the project. The estimate of $318 million is based on pricing received during the RFP process.

Q. Why are you accounting for meter replacements?

A. There are two primary reasons. First, the meters have an estimated useful life of 15 years. Therefore a portion of the meters that will be installed will have to be replaced before the end of the project life. Second, based upon discussions with other utilities involved in smart meter projects, the Companies have assumed a one percent failure rate through 2022 and a 2 percent annual failure rate thereafter. While no costs for meter failures were included during the first five years of the meter's life because our analysis assumes that any such failures would be covered under the manufacturer's warranty, replacement costs had to be factored in for failures beyond the warranty period.

Q. How were the cost estimates for each of the cost categories developed?

A. Except for the "Business Staffing," "Systems Integration" and "Communications and Change Management" costs, all other costs are based on price quotes received through the RFP process and are relatively firm. Companies Witness Iorio discusses the RFP process in his testimony.

Q. How were the Business Staffing costs determined?

A. The Business Staffing costs were estimated based upon joint analysis of the SMIP Team's estimated internal requirements coupled with IBM's experience with other smart meter deployments at Oncor and Centerpoint Energy. The Business Staffing budgets were developed from the ground up using Full Time Equivalent ("FTE") estimates and were then compared to IBM's experience with its other clients, adjusting qualitatively for factors such as the size of the Companies' deployment and the additional effort that would be required to deploy meters in four service territories.

Q. How were the costs associated with Systems Integration determined?

A. The Systems Integration Costs were provided by IBM, based upon past experience with systems integration projects at other utilities, adjusting for differences in variables such as size and scope of the project and deployment time frames.

Q. How were the costs associated with Communications and Change Management determined?

A. The Communications and Change Management cost estimates were developed by IBM and Black & Veatch consultants based on their collective experience with utilities such as ONCOR, Centerpoint Energy, BC Hydro, Commonwealth Edison Co. ("Com Ed") and Central Maine Power, and were vetted with and approved by the SMIP Team and its management. I developed the Communications and Customer Outreach cost estimates in concert with the Companies' Communications Department and SMIP Team, focusing on the specific media outlets that served the Companies' service territories, the frequency and types of messaging that would be required and the collective experience of my Black & Veatch colleagues with other deployments such as Central Maine Power, Com Ed, and Southern Maryland Electric Cooperative.

Q. How do the estimated costs of the Deployment Plan compare to those of other utilities?

A. The Companies' all-in cost on a per meter basis for the 2019 Recommended Scenario is approximately $375. This number includes all capital and O&M costs incurred during the Deployment Period for 98.5 percent deployment of the meters in the Companies' service territories. While the Companies expect the per meter installation cost to be slightly higher for the remaining 1.5 percent of the installations, given the relatively few meters involved, the Companies do not anticipate a significant impact on the average per meter cost. Using this same deployment cost definition, I found that the estimated cost per meter were $343, for approximately 221,000 meters in Delmarva's service territory; $327, for approximately 571,000 meters in PEPCO (Maryland); and $357, for approximately 4 million meters in Com Ed's territory. Given these results, the projected costs included in the Deployment Plan are quite reasonable, especially when factoring in the diverse terrain and population densities within the FirstEnergy Pennsylvania footprint. Further, both the Delmarva and PEPCO deployments began in the 2009-2010 timeframe and Com Ed's will begin in 2015. Thus, the Companies' estimates would be expected to be somewhat higher due to capital cost and wage escalation between today and when full-scale deployment starts in 2017.

IV. Estimation and Tracking of Smart Meter Cost Savings

Q. Did the Companies estimate the potential amount of savings that could be generated through the implementation of their smart meter Deployment Plan?

A. Yes. Act 129 requires the Companies to net any savings realized from the implementation of smart meter technology against the costs of the project. Therefore, the Companies analyzed the potential savings that could result from the installation of smart meter technology and developed a methodology to measure and verify those savings.

Q. What have the Companies estimated as savings that might be generated from the installation of smart meter technology?

A. Potential operational cost savings have been estimated to be approximately $406 million on a nominal cost basis. The vast majority of these potential savings are expected to be achieved through the eventual elimination of most meter reading services, with the remainder coming from a reduction in meter support services, back office services and Contact Center services. I have summarized the estimated savings that the Companies believe they can achieve on Exhibit GLF-4, Summary of Operational Cost Savings Categories. A more detailed discussion of the nature of the savings and how these savings were estimated can be found in Chapter 4 of the Deployment Plan.

Q. How will the Companies track and verify the savings realized through the installation of smart meter technology?

A. The Companies will have to establish base line employee levels, costs and other metric levels and then track and compare results each year during the Deployment Period to those baselines.

Q. What baselines will be used when tracking the savings that are achieved through the installation of smart meter technology?

A. Baselines will be set on the date on which deployment begins. As of now, it is expected that the Deployment Plan will be approved no later than September 30, 2013 and that actual deployment will commence in early 2014. Therefore, assuming deployment can begin as scheduled, the baselines will be based on actual personnel, asset and operational levels in all of the affected areas as of December 31, 2013. However, when necessary, the Companies will adjust for any anomalies in the 2013 data.

Q. How will the Companies track savings realized from the deployment of smart meter technology?

A. Generally, the Companies will compare actual results for each year of the deployment to the baselines and adjust the cost recovery riders for any reductions in costs that can be attributable to the installation of smart meter technology. A more detailed explanation of how these costs will be tracked is set forth in Chapter 4 of the Deployment Plan and Companies Witness Valdes discusses how these savings will be incorporated into the cost recovery riders.

V. <u>Stakeholder Activity</u>

Q. Did the Companies seek stakeholder input when developing the Deployment Plan?

A. Yes. The PA Companies performed market research through customer surveys and focus groups and the SMIP Team hosted various stakeholder meetings with interested parties so as to gain a better understanding of stakeholders' views on various smart meter issues.

Q. Please describe the smart meter related market research that was performed by the SMIP Team.

A. The SMIP Team conducted six focus group sessions through the Shelton Group and conducted customer/market surveys through the TRIAD Research Group. Due to the timing of the approval of the merger between FirstEnergy and Allegheny, West Penn was not included in this type of research. The purpose of this research was to gain a better understanding of customers' views on and knowledge of smart meters for purposes of developing a customer education plan. As part of a commitment made by West Penn, the

SMIP Team also commissioned Black and Veatch to perform load research-based analyses on residential customers, which I oversaw. This research focused on assessing kW and kWh usage data for low income and vulnerable customers in both West Penn's and the other Companies' service territories. The purpose of this load research was to try to identify any usage level and load shape differences between these groups of customers and the rest of the residential customer base. The results of this research were made available to the Office of Consumer Advocate and other parties interested in this topic at meetings held on December 8, 2011, February 21, 2012, May 31, 2012 and October 19, 2012.

Q. Did the Companies hold any other stakeholder meetings?

A. Yes. The Companies also hosted several stakeholder meetings in which progress on the development of the Deployment Plan was discussed and specific topics of interest, such as sub-hourly metering and data access, were explored. These meetings were held on August 17, 2011, February 21, 2012, May 31, 2012, and December 13, 2012. On August 17, 2011 and February 21, 2012, the Companies invited all members of the stakeholder groups of West Penn and the PA Companies, representing approximately 25 different interests, to a meeting in Harrisburg to discuss sub-hourly metering issues, expressly addressing all issues outlined in the Commission's April 15, 2010 Order in Docket No. M-2009-2123950. Companies Witness Iorio discusses the results of these meetings in his testimony. The August 17th meeting, as well as the May 31st and December 13th meetings were held so as to provide updates on the development of the Deployment Plan.

VI. Employee and Customer Communication, Change Management and Training

Q. Have the Companies developed a customer education and communications plan?

A. They are in the process of doing so. In addition to the market and load research performed, the SMIP Team visited several utilities in various stages of smart meter deployment. A major topic of discussion during each visit was the education of and communication to employees, customers and other interested parties on smart meter related issues. The SMIP Team is in the process of assimilating all of this information and developing an Internal and External Communications Plan ("Comm Plan") that will focus on communications with and the education of employees, customers and others during the implementation of the Deployment Plan. The Comm Plan will have the flexibility to be updated throughout the Deployment Period to reflect customer concerns and deployment hurdles as encountered by the Companies. The strategy underlying this Comm Plan is discussed in more detail in Chapter 6 of the Deployment Plan.

Q. How will the Companies manage content of the Comm Plan?

A. The Companies understand that, inevitably, the Comm Plan must evolve and change throughout the deployment process as unexpected circumstances arise. Customers may have different primary concerns from what is expected and the deployment process may face hurdles different from those anticipated. Therefore, the Comm Plan will remain flexible in order to respond to shifting smart meter implementation schedules, timing of meter and new technology functionality and as issues and new developments emerge. The Companies anticipate working with interested parties in the development of the content of the communications to various audiences throughout the implementation of the Deployment Plan.

Q. Have the Companies developed a Transition Plan and a Training Plan?

A. These too are in progress. Because the Companies recently selected their vendors and technology solutions, and because the Deployment Plan has not yet been approved, all of the details are not yet available to complete these plans. However, the strategies underlying both the Change Management and the Training Plans are described in Chapter 6 of the Deployment Plan.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit GLF-1

George Fitzpatrick

Mr. Fitzpatrick's professional experience includes over 35 years within the utility management and electric/gas management consulting fields. Mr. Fitzpatrick's areas of expertise include: economic and econometric analysis for energy and peak forecasting, load research, integrated resource planning, demand side management and related areas, as well as nuclear and fossil generating plant life cycle economics, operating costs and performance modeling and overall utility investment prudence analyses. He has testified extensively throughout the U.S. before the FERC and state regulatory commissions, in both direct and rebuttal roles. Areas in which he has provided testimony include:

- Lifecycle economic analysis of nuclear generation investments
- Nuclear generation operating costs and performance modeling
- Nuclear and total utility operating performance standards
- Integrated Resource Planning
- Electric and Gas Demand Side Management / Energy Efficiency (DSM/EE) Program Assessment, Implementation and Evaluation
- Comparative lifecycle economics of competing utility investments
- Smart Meter Business Case Analyses
- Econometric/statistical-based Peak Load and Energy / Sales Forecasting
- Other Econometric and Statistical Studies on Utility- related Issues
- Weather Normalization Studies
- Strategic Planning
- Load Research Program Sample Design, Implementation and Analysis
- Rate Design
- Cost of Service Studies
- Renewable Program Evaluation
- Performance Standard design and statistical construction
- SAIDI / SAIFI-related statistical investigations

During Mr. Fitzpatrick's consulting career he has provided services to over 50 electric and gas utility clients both in the U.S. and abroad. However, there are a number of clients that have utilized his services on an ongoing basis over the years as a senior management consultant and/or expert witness. These clients include:

- American Electric Power Corp.
- Arizona Public Service Company (Pinnacle West)
- Bermuda Electric Light Company Limited
- Centerpoint Energy
- Consolidated Edison Company of New York
- El Paso Electric Company
- Entergy
- FirstEnergy
- Freeport Electric

EXECUTIVE MANAGING DIRECTOR

Specialization:
DSM Planning, Implementation and Evaluation; Nuclear Lifecycle Economic, Cost and Performance Analyses; Load & Energy Forecasting; Econometric & Statistical Analysis; 30 Years of Expert Testimony Experience

Education

- St. John's University, M.B.A., Economic Theory, 1972
- St. John's University, B.A., Economics, 1969
- C.W. Post College, course work toward an MS, Management Engineering

Mr. Fitzpatrick has also completed course work in Engineering Economics, Load Research, Demand Forecasting, Box-Jenkins Forecasting Techniques, logistic curve analyses; two and three stage multiple regression techniques; advanced econometric modeling and the utilization and interpretation of multiple regression models and associated analytical techniques

Total Years Experience
30

Professional Associations

- Association of Energy Engineers
- American Statistical Association
- American Economic Association
- Mathematical Association of America
- Omicron Delta Epsilon
- Advisor to American Management Association

- Georgia Power Company (Southern Company)
- Guam Power Authority
- KeySpan Energy
- National Grid
- New England Electric System
- Niagara Mohawk Power Corp. (National Grid)
- New York Power Authority
- Ontario Power Generation
- Public Service Company of Oklahoma
- San Diego Gas & Electric
- Southern Maryland Electric Cooperative
- TXU Electric (TXU)
- Union Gas Co. Ltd.
- United Illuminating Co.
- Westar Energy (and its three predecessor companies)

He has also served his client base as a negotiator, often playing a key role in the negotiation of multi-million dollar, short and long term utility power supply and franchise contracts (e.g., Ft Bliss, White Sands Missile Range, University of Texas, and El Paso Water Utilities and El Paso Electric Vs. the City of Las Cruces).

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony & Regulatory Support (Selected Assignments)

American Electric Power and Public Service Company of Oklahoma | Docket Nos. 200500516, 200600030, and 200700012

Provided direct and rebuttal expert testimony on the overall prudence of AEP's Integrated Resource Planning processes and results with specific focus on AEP's load forecasting processes and comparative lifecycle economic analyses of supply and demand side alternatives.. Also provided an analysis of the short and longer term potential for cost effective Demand Side Management in the PSO service territory based upon my earlier work on this subject for the entire AEP system and its 11 operating companies.

Arizona Nuclear Power Project - Palo Verde

Developed computer software to facilitate budget tracking and comparison. Developed econometric-based target estimation models of Operation and Maintenance Costs. Developed target estimation of Capital Additions Costs based upon econometric modeling. Developed forced and planned outage statistical models to be used in regulatory proceedings for all participants as well as for internal outage planning. Acted as Advisor to Palo Verde Participant's Engineering and Operating Committee on Palo Verde Cost and Performance budget targeting.

Arizona Public Service Company | Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827

Provided rebuttal testimony on the practical and statistical considerations to address when designing a nuclear plant operating performance standard. This testimony presented the results of his non-linear multiple regression models as they apply to this subject. Further, it referenced his prior work on behalf of Georgia Power Company developing an operating performance standard for Plants Vogtle and Hatch.

Arizona Public Service Company | Palo Verde 1, 2, & 3 / Docket Nos. U-1345-85-156 and U-1345-85-367

Provided direct testimony presenting comparative economic analysis of Palo Verde vs. hypothetical coal unit alternative. Provided econometrically developed estimates of Operation and Maintenance Costs, as well as Capital Additions Costs. Provided independent statistically derived estimates of lifecycle Capacity Factors for the Palo Verde units. Participated in the training of APS witnesses.

Atlanta Gas Light - Georgia (1997)

Worked with senior management to develop testimony for a performance based rate plan in support of the unbundling of gas service.

El Paso Electric Company | Palo Verde 1 & 2 / Texas - Docket No. 7460

Provided direct testimony on lifecycle economics of nuclear vs. coal alternative. Provided direct testimony on decisional prudency of company to enter into nuclear investment. Provided load forecast of company's future energy and peak demand needs. Participated in the training of Company witnesses.

El Paso Electric Company | Palo Verde 1, 2, & 3 / Docket Nos. 8892, 9069 and 9165

Provided Direct Testimony presenting comprehensive industry analysis and statistical analysis of Nuclear Performance Standards. Presented statistically derived optimal Performance Standard for Palo Verde Units 1, 2, and 3. Provided Rebuttal Testimony discussing theoretical and statistical flaws in intervener's Performance Standard proposal.

El Paso Electric Company - Texas (1997-1998)

Developed unbundling strategy and performance based rate plan in support of ongoing Texas PUC workshops on the unbundling of electric service.

Empire District - Missouri (1992)

Provided econometric rebuttal testimony critiquing MPSC Staff's direct testimony on Empire District's forecast. Staff accepted rebuttal testimony and the Company's forecast was accepted for use in the rate case.

FirstEnergy Ohio Operating Companies | Cleveland Electric Illuminating Company / Docket No. 12-2190-EL-POR; Docket No. 12-2191-EL-POR; Docket No. 12-2192-EL-POR

Presented and successfully defended the results of an Energy Efficiency Market Potential Study that served as the underpinning of FirstEnergy Companies 2013-2015 Energy Efficiency Program Portfolio.

FirstEnergy Ohio Operating Companies | Cleveland Electric Illuminating Company / Docket No. Docket No. 09-1947-EL-POR Docket No. 09-1942-EL-EEC Docket No. 09-580-EL-EEC; Ohio Edison Company / Docket No. 09-1948-EL-POR; Docket No. 09-1943-EL-EEC; Docket No. 09-581-EL-EEC; Toledo Edison Company / Docket No. 09-1949-EL-POR; Docket No. 09-1944-EL-EEC; Docket No. 09-582-EL-EEC

In 2011, Fitzpatrick provided direct testimony presenting, updating and supporting the Energy Efficiency and Peak Demand Reduction Plans of the Companies originally developed by Fitzpatrick in 2009 in response to the requirements of S.B. 221.

FirstEnergy Pennsylvania Operating Companies | Metropolitan Edison Company / Docket No. M-2009-2092222; Pennsylvania Electric Company / Docket No. M-2009-2112952; Pennsylvania Power Company / Docket No. M-2009-2112956

Provided direct and supplemental testimony presenting, updating and supporting the Energy Efficiency and Conservation Plans of the Companies developed in response to the requirements of PA Act 129. Also provided rebuttal testimony on a variety of related issues raised by the other parties in the three dockets.

Freeport Electric | 1995 Docket No. 95-E-0676, 2001 Docket No. 01-E0965, 2003Docket No. 03-E-0686

Provided direct testimony supporting Freeport’s KWH sales and peak demand forecasts in four NYPSC proceedings. Constructed econometric models based forecast methodology by calls along with weather normalization of the test year sales. Provided testimony on the selection of Freeport-specific DSM programs to meet Commission requirements.

Georgia Power Company | Plant Hatch and Plant Vogtle / Georgia - Docket Nos. 3554-U and 3673-U

For the Vogtle Financing Case, the Vogtle Rate Case and the Hatch Rate Case: Provided rebuttal testimony on comparative economics of Plant Vogtle, provided rebuttal testimony (with presentation to Commission) on Vogtle's economics, and statistically derived projections of Vogtle's performance and Hatch O&M Costs, participated in witness training, and developed internal statistically-based O&M and Capital Additions "Targets" for Plant Hatch and Plant Vogtle.

Georgia Power Company | Plant Hatch and Plant Vogtle / Docket No. 3840-U

Provided Rebuttal Testimony that pointed out methodological and statistical flaws in Staff consultant's Performance Standard proposal. Presented parameters for a statistically unbiased, optimal Performance Standard.

Kansas Gas and Electric Company | Wolf Creek / Kansas City Power and Light Company/Kansas-1984 Docket Nos. 84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185

Provided rebuttal testimony on lifecycle economics of nuclear vs. coal alternative. Provided first-year and lifecycle statistically based estimates of Wolf Creek's Operation and Maintenance Costs and Capital Additions Costs. Provided first-year and lifecycle estimates of Wolf Creek's Capacity Factors. Participated in the preparation of KG&E witnesses on the subjects of statistics, econometrics, forecasting, and engineering economics.

Long Island Lighting Company | Shoreham / New York-Docket No. 28252

Provided rebuttal testimony on most likely performance of Shoreham Unit. Provided testimony on most likely Operation and Maintenance Cost levels and Capital Additions Cost level for Shoreham based upon econometric analysis of nuclear industry. Provided testimony on demand-side vs. supply-side alternatives for the Long Island Lighting Company.

Long Island Lighting Company (1974-1979)

Testified as an expert witness, usually in both the direct and rebuttal phases, in the following New York State Public Service Commission proceedings: Docket Numbers:, 26733, 26829, 26985, 27136, 27154, 80003, 27319, 27374, 27375, 28223, 28252, on subjects such as econometric and econometric-end use Electric and Gas Peak and Energy Forecasts, Load Research studies for cost-of-service analysis, Load Management, Cogeneration, Conservation and statistical studies for weather normalization of gas send out and electric energy requirements data.

Minnegasco | Docket No. G-008/GR-92-400 (1993 - 1994)

Developed a set of econometrically derived, short run forecasts for Minnegasco's major customer classes. Provided direct expert testimony regarding the use of these forecasts as a factor in determining the need for and magnitude of Minnegasco's requested rate increase. Assisted in preparation of cross-examination of intervening parties.

On rebuttal, supported the implementation of weather normalization adjustments and discussed the effects of an adjustment on varying classes of customer use.

All testimony was accepted by Staff.

Missouri Public Service (MOPUB) - (1992)

Provided econometric-based rebuttal testimony critiquing MPSC Staff's direct case criticizing MOPUB's forecast. Rebuttal testimony resulted in Staff stipulating to the use of the Company's forecast.

Southern Maryland Electric Cooperative | Maryland Public Service Commission / Docket No. 9294

Provided direct and reply testimony related to the development of Time of Use Rate proposals on behalf of Southern Maryland Electric Cooperative. Also, developed likely short term and long term price elasticity effects for these TOU proposals.

United Illuminating Company | October 2008 Connecticut DPUC Docket 08-07-04

"Application of the United Illuminating Company to Increase its Rates and Charges"—provided direct testimony concerning UI's long term econometric-based kWh sales and system peak forecasts and UI's 2000-2008 normalized system peak analyses. Offered perspectives on the structural differences between, and objectives of, long term planning forecasts vs. short term financial forecasts.

United Illuminating Company | July 2007 Connecticut Siting Council Filing

Developed econometric-driven peak load and energy sales by class forecasts for the company. Performed a multi-year weather normalization analysis of UI's summer peaks and energy sales. Provided support for UI witnesses in the 2007 Siting Council hearings held in June 2007.

Westar Energy | 2005-2007 KCC Docket Nos. 05-WSEE-981-RTS and 07-WSEE-616-PRE

In the 2005 docket, provided direct and rebuttal testimony on the subjects of distribution reliability and reliability-based performance standards. Developed a series of statistical analyses that set performance standards for five utility performance metrics: SAIDI, SAIFI, EFOR, Answered Calls and Meters Read. Developed daily 1998-2004 SAIDI and SAIFI non-linear multiple regression-based weather normalization models for use by the Company.

In the 2007 docket provided both direct and rebuttal testimony on the subjects of peak and energy forecasting, DSM program potential and budgeting, and peak and energy weather normalization analyses.

Western Resources Inc. and Kansas Gas and Electric Company | 2000 KCC Docket No. 01-WSRE-436

Sponsored two adjustments necessary to normalize operating revenues and expenses for the test year. Performed a review of KPL's and KGE's sales and peak demand forecasting methodology. This review was performed to evaluate its accuracy and unbiaseness since this forecast, in part, supports the Company's decisions to install new capacity. Also performed a statistical review of KPL's and KGE's peak demand normalization methodology, which is necessary to analyze the accuracy of the KPL's and KGE's peak demand forecasts.

Western Resources | 1996 KCC Docket No. 193,307-U96-WSRE-101-DRS

Provided expert testimony and supporting statistical analysis for test year, class weather normalization, as well as, primary and secondary economic benefits of key customer discounted contracts.

Demand-Side Management Program Design, Implementation, & Evaluation

Overview

George Fitzpatrick has over 35 years experience in performing DSM/EE technical and economic potential assessments, program implementation and program evaluations for his electric and gas utility clients. His strong economic, statistical and ESCO business background has enabled him to advise clients on effective DSM/EE initiatives, provide unbiased evaluations of both electric and gas supply and demand side resources, operate successful ESCO's on behalf of his utility clients and finally manage the evaluation of over 300 DSM/EE programs.

Over this same 35 year span he has served as an expert witness on a number of subjects related to the DSM/EE practice area. It should be noted that his long professional career as an expert witness attests to the fact that he is a knowledgeable professional who has and continues to offer reasonable perspectives on the subjects to which he provides expert testimony. This same ethic carries over to his conduct of consulting assignment for clients.

The following paragraphs provide a representative sample of the DSM/EE work that he has performed over his professional career:

American Electric Power

In 2004-5 he directed an eleven operating company DSM/EE measure assessment that included the estimation of the economic and load/energy impacts of over 80 measures, customized where appropriate to each of AEP's operating companies. As part of this assignment, he directed the development of conditional demand analyses for the purpose of developing individual service territory-specific impacts for certain weather sensitive measures. This work served as a basis for AEP's decision to more fully engage in DSM/EE activities. Mr. Fitzpatrick also served as AEP's overall IRP prudency and DSM/EE witness in PSO's 2007 Oklahoma IRP-related docket.

Bermuda Electric Light Company, Ltd.

Directed a 1990-1991 multi-faceted evaluation of the potential for DSM on Bermuda. Conducted in-depth research of various customer classes to determine likelihood of adoption of available DSM technologies. Building on this research, developed a series of pilot programs that were implemented in 1993, as well as evaluation strategies to be employed at the programs' conclusion. Designed and served as the responsible officer for the creation and staffing of a full service energy services company, BESCO, that commenced operation in 1995 and provides, to this day, a full range of energy efficiency, energy security and power protection products and services to residential, commercial and industrial customers in Bermuda.

Consolidated Edison Company of New York, Inc.

Project Manager for a 1981 Conservation Assessment Study which included designing a methodology and performing analysis to impact Conservation measures in the residential and commercial sectors to meet requirements imposed by New York PSC in Case No. 28223.

El Paso Electric Company's Energy Service Business Unit (ESBU)

From 1996-2001, Mr. Fitzpatrick served as the General Manager of El Paso Electric's ESBU, a full service ESCO that he conceived, staffed and managed until this unit was spun off as a wholly-owned subsidiary of EPE. Although a consultant to EPE, Mr. Fitzpatrick had full operating authority and served as authorized agent of the company for contracting and procurement matters. This profitable business unit designed and negotiated long term power supply contracts that had value adding components such as large chilled water storage plants (University Of Texas-El Paso), emergency backup generation for water and wastewater facilities (El Paso Water Utilities), innovative time of use rates that provided for increased security for military installations and pipeline operations (e.g., Ft Bliss, Holloman Air Force Base, White Sands Missile Range, NASA, Diamond Shamrock, shopping centers, office parks and the like.

Jersey Central Power & Light (JCP&L)

Performed a 2006-7 assessment and recommended a portfolio of targeted peak load management initiatives to achieve significant reductions of electric loads on both a substation and system wide basis. These programs served as a significant component of JCP&L's submission to the New Jersey Energy Master Plan (2007).

Long Island Lighting Company (LILCO)

Directed a 1993 research project focusing on the right-sizing of LILCO's DSM program in the face of maturing market conditions, as well as on the measurement of the extent to which LILCO's programs had successfully moved the market to energy efficient technologies. Research includes an assessment of the impacts of pure market forces on DSM and the role of rebates and information in overall market capture for DSM technologies.

Project Manager for LILCO's 1992 Research and Development Initiative entitled, "Institutional Barriers to Conservation in Master-Metered, Tenant-Occupied Commercial Office Space." The project involved estimating the market conservation potential, identifying institutional barriers through focus groups and interviews with landlords and tenants, and establishing a pilot program and blueprint lease to implement in order to enhance DSM measures in the relevant market.

Directed the comprehensive evaluation of LILCO's 1987 Conservation and Load Management Programs. This evaluation is contained in a three-volume report, which has been called the "most comprehensive" effort to date in this area.

Directed the evaluation of LILCO's 1988 and 1989 Conservation and Load Management Programs. Directed the preparation of a June 1988 Load Management Study. Specific responsibilities included estimating Load Management reductions included in LILCO's Load Forecasts by major components.

Minnegasco

Served as the Senior Management Advisor to Minnegasco's DSM/Load Research Program from 1993 through mid-1995. Responsibilities included contract negotiations with consultants, supervision of consultant's activities, and resolution of technical issues, and on-site presence as required to effectively oversee all Load Research-related activities.

New York Power Authority (NYPA)

Served as the Senior Management Advisor (1992-present) for NYPA's $1 Billion High Efficiency Lighting Program (HELP) and its successor programs having primary responsibility for drafting and negotiating DSM cost sharing umbrella contracts with New York State and New York City, serving as project executive during the program’s 18 month startup and directing multiple implementation contractor management and quality assurance efforts.

Analysis on behalf of NYPA of Energy Systems Research Group's (ESRG) Conservation Assessment Report submitted in FERC Case No. 2729: Prattsville Pumped Storage Facility.

Supervised the development of an evaluation of potential Load Management strategies for the NYPA's municipal customers, including a cost/benefit analysis and specific Load Management test programs.

New York Power Pool

Analyzed the conservation forecasts contained within the Member Systems' individual long-range forecasts and evaluated all parties’ conservation forecasts and analyses.

New York State Electric & Gas Corporation (NYSEG)

Served as Responsible Officer for NYSEG's 1991 & 1992 Commercial / Industrial Process and Impact Evaluations. Served as Responsible Officer in the development of NYSEG's June 1994 DSM Market Transformation Study.

Orlando Utilities Board

Directed a 2007 comprehensive assessment of the maximum and technically feasible potential for DSM/EE measures in the OUB service territory. Measures were evaluated based upon lifecycle economics from varying stakeholder perspectives. Developed a short list of most applicable measures for the OUB service territory and directed the development of 8,760 hour load shapes for each short-listed measure. This work was utilized in OUB's 2007-2008 IRP filing.

Orange and Rockland Utilities (O&R)

Assessed the potential for and designed an Energy Cooperative Program for O&R's commercial customers. Directed project to assess new regulated and unregulated business opportunities to diversify O&R from its core business.

Rochester Gas & Electric Corporation

Served as Responsible Officer for RG&E's 1990-94 DSM Evaluations. Represented RG&E in all DSM-related interactions with PSC Staff.

Westar Energy

Developed the initial 2006-2007 DSM/EE program menu that included program by program projected impacts and lifecycle economics for consideration by Company senior management. Further developed Westar's peak load and energy forecasts that included both programmatic and free market substitution DSM/EE effects. Worked with the Company and Commission to explore appropriate mechanisms for DSM/EE program implementation and predetermined cost recovery

SELECTED CONSULTING ASSIGNMENTS

Westar Energy

Mr. Fitzpatrick served as the Principal statistical consultant on a joint Distribution Reliability project with Davies Consulting. This project had as its objective the evaluation of Westar's distribution integrity and repair metrics (i.e., SAIFI and SAIDI) and the development of non-linear multiple regression models to normalize these metrics over time for those major weather elements affecting SAIFI and SAIDI performance. The results of this analysis were presented to both Westar Senior Management and the Kansas Corporation Commission.

Generation Investment Analysis (Westar La Cygne 2 and SDGE SONGS related analysis.)

Westar La Cygne 2 Sale Leaseback Analysis

Provided an industry based statistical study of lifecycle availability and O&M cost Expectation in connection with Westar Sale/Leaseback of the La Cygne 2 Unit.

San Diego Gas & Electric | SONGS O&M and Capital Additions

Served as the technical project manager for the development of several non-linear multiple regression analysis developed to evaluate SONGS mayor cost components as compared to a focused sample of like plants.

Freeport Electric

Served as the principal-in-charge of the statistical analysis to develop the Freeport Electric 2005 Normalized System Peak and the estimation of Freeport's 2006 ICAP peak responsibility for the New York ISO. Also served as the project manager for the development of Freeport Electric's 2005 Load & Energy Forecasts.

Duquesne Light Company

Served as the Principal-in-charge of the statistical analysis to develop Duquesne Light's 2005 Normalized Summer Peak as well as the development of the major rate class contribution to that peak.

El Paso Electric Company

Developed a business plan for and then implemented an Energy Services Business Unit (ESBU) that had as its mission key customer retention contracting and the provision of value added products and services in the areas of energy efficiency, power quality, standby generation, and "behind the fence" maintenance and support services.

Planning & Forecasting (Selected Projects)

New York State Electric & Gas Corporation (NYSEG) - (1994 -1997)

Served as Responsible Officer for AEG's development of a Multi-Equational Small Area Forecast Modeling System. This system is used to track monthly sales geographically in the NYSEG system, identifying significant weather normalized monthly variances almost in "real time" so that NYSEG can recognize and react to significant changes in a shorter elapsed time.

Western Resources/Westar (1984 - 2004)

Provide continuing advisory services to Western Resources (now Westar) on potential methodological upgrades to their forecast and weather normalization methodologies.

Long Island Lighting Company (LILCO)

Directed the preparation of LILCO's Annual Long Range Peak and Energy Forecasts during the years 1974 - 1979. Constructed the first Engineering End Use and Econometric End Use models for electric forecasting in New York State; utilized Box-Jenkins stochastic and multiple transfer functions for short run electric forecasts; employed two and three stage regression techniques in SIC-based commercial-industrial forecasting.

In 1994, provided advisory services to review adequacy of the econometric methodologies for the capture of "market transformation" DSM and efficiency effects.

Saudi Arabia SCECO East (1995)

Selected from an international list of experts to perform a comprehensive review of Saudi Arabia's largest utility's overall planning and forecasting procedures, methodologies, and results. This two-phase project also called for the reengineering of these processes once the analytical and fact-finding phase was complete.

Bermuda Electric Light Company, Ltd. (BELCO) - (1994)

Reviewed BELCO's existing forecasting process and provided a "phase in" solution for enhancing their forecasting systems.

Freeport Electric (1995-2004)

Have and continue to prepare Freeport’s short and long-term electric peak and energy forecasts. Have presented and defended Freeport’s forecasts and weather normalization studies in its last three rate cases.

Innovative Market Segmentation & Profitability Studies

Western Resources

Served as Responsible Officer for a Competitive Assessment of Western Resources key customer’s responses to cost competition.

Union Gas Limited 2004

Performed a detailed evaluation of the Union Gas forecasting methodology and results. Developed a written report containing an evaluation opinion and forecast improvement suggestions. This report was filed with the Ontario Energy Board.

CINergy

In 1995, advisor to senior staff in a multi-phase project that had as its objective the meaningful (from a risk-profit perspective) segmentation of CINergy key customer markets and the analysis of profitability of the segments. This was followed by the development of strategies to optimize the use of CINergy's marketing resources to maximize shareholder returns while ensuring the long-term viability of the company.

Load Research

Westar Energy 2006-2007

Redesigned Westar’s load research program to account for new rate classes and the emerging need to perform conditional demand analyses to support DSM assessment in the future. Redesigned and administered a residential and commercial appliance/ed uses study that linked to the new load research sample designs.

Electric Power Research Institute

Advisor to EPRI's Demand Program. Author of RP 1588-3 "Load Data Management and Analysis"; co-author of EPRI Rate Design Study Topic Paper 3: "Issues in Load Research."

Elizabethtown Gas Company

Asked by Senior Management to assess Elizabethtown's Load Research Program and develop a set of recommendations that would result in full cost-effective utilization of the Load Research resource, developed study plan, conducted in-depth technical interviews of potential load research clients, and presented findings and recommendations to all levels of Management.

Iowa Power Company

Directed weather normalization analysis on historical system peak demands. Results from analysis will be utilized in future system peak demand forecasts.

Long Island Lighting Company

Designed and implemented stratified sampling software that employed Dalenius-Hodges and Neyman Allocation techniques with stratum optimization and validation. Also directed LILCO's Load Research Program.

New England Power Service Company

Reviewed NEPSCo's Load Research Data Management and Analysis System from analytical and data perspectives and developed a NEPSCo-specific computer hardware and software plan for implementation.

New York Power Authority

Directed the review of the existing Load Research Program and formulated a Management Plan to specify future needs in the areas of sample design, hardware, software, and staffing.

Assisted in the development of specifications for a microcomputer-based Load Research Data Collection, Editing and Analysis System.

New York State Electric & Gas Corporation

Served as Technical Advisor to the Manager of NYSEG's Load Research Department.

Northeast Utilities Service Company

Performed a comprehensive audit of the technical, software, and organizational aspects of the Northeast Utilities Load Research Program, including the identification of current uses and recommended future cost-effective uses within the company.

Supervised development of a study to analyze load research, weather, and attribute data for the small Commercial and Industrial customer group.

Northern States Power Company

Directed the review of all aspects of NSP's load research process and presented findings in a comprehensive presentation to senior management.

Pacific Gas & Electric Company

Performed a comprehensive audit of the PG&E Load Research Data Management and Analysis System. Also, assessed the value of Load Research to all relevant departments in the company including recommendations for more cost-effective uses of Load Research data for both current and future applications.

Smart Meter Implementation Planning

Served as the Lead of the regulatory and communications workstream for the FirstEnergy Smart Meter Implementation Plan project. As lead of this workstream, Mr. Fitzpatrick was responsible for planning and implementation regulatory and collaborative communication initiatives, designing and conducting appropriate customer and market research that would serve to aid the construction of the Companies' business case, and interacting with FirstEnergy executives and interanle project sponsors and managers on project activities.

Exhibit GLF-2

Summary of Total Costs, Cost Savings and Net Costs

	Capital Cost (A)	O&M Cost (B)	Total Cost (C) = (A) + (B)	Cost Savings (D)	Net Cost (E) = (C) - (D)
Scenario: 90.0% Deployment by 2018					
Nominal	$676,166,067	$583,153,567	$1,259,319,634	$415,532,240	$843,787,394
NPV	$400,039,680	$301,496,952	$701,536,632	$139,771,677	$561,764,955
Scenario: 98.5% Deployment by 2019					
Nominal	$675,545,057	$582,050,231	$1,257,595,288	$405,518,837	$852,076,451
NPV	$393,662,712	$299,897,997	$693,560,709	$133,876,123	$559,684,586
Scenario: 98.5% Deployment by 2020					
Nominal	$674,779,030	$580,244,419	$1,255,023,449	$389,789,682	$865,233,766
NPV	$384,207,068	$297,449,834	$681,656,902	$125,145,414	$556,511,488

Exhibit GLF-3

Exhibit GLF-3

Summary of Costs by Categories
98.5% Deployment by 2019 Scenario

Capital		**Total PA**
Meter & Local Area Network	$	343,446,302
Information Technology	$	265,482,737
Systems Integration	$	54,932,380
Network & Network Mgmt	$	160,000
Program Mgmt	$	1,478,571
Business Staffing Requirements	$	9,658,029
Communications/Change Mgmt	$	387,038
Capital Costs Total	**$**	**675,545,057**

O&M		**Total PA**
Meter & Local Area Network	$	84,885,411
Information Technology	$	277,228,558
Systems Integration	$	32,259,424
Network & Network Mgmt	$	16,230,992
Program Mgmt	$	13,406,417
Business Staffing Requirements	$	118,804,426
Communications/Change Mgmt	$	39,235,003
O&M Costs Total	**$**	**582,050,231**

Total Costs		**Total PA**
Meter & Local Area Network	$	428,331,713
Information Technology	$	542,711,295
Systems Integration	$	87,191,804
Network & Network Mgmt	$	16,390,992
Program Mgmt	$	14,884,988
Business Staffing Requirements	$	128,462,454
Communications/Change Mgmt	$	39,622,042
Total Costs	**$**	**1,257,595,288**

Exhibit GLF-4

Exhibit GLF-4

Summary of Operational Cost Saving Categories
98.5% Deployment by 2019 Scenario

Category	Savings Amount (Nominal Basis)
Meter Reading	
Meter Reading O&M	$368,955,939
Meter Reading Handhelds O&M	$979,427
Meter Reading Handhelds Capital	$2,359,063
Claims	$474,860
Subtotal	**$372,769,290**
Meter Services	
Meter Services O&M	$9,961,302
Meter Services Handhelds O&M	$44,420
Meter Services Handhelds Capital	$947,290
Subtotal	**$10,953,013**
Back-Office	
Back-Office/ Cust. Accounting O&M	$17,922,492
Contact Center	
Contact Center O&M	$3,874,043
Cost Savings Total	**$405,518,837**

STATEMENT NO. 5

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
Docket No.

PENNSYLVANIA ELECTRIC COMPANY
Docket No.

PENNSYLVANIA POWER COMPANY
Docket No.

WEST PENN POWER COMPANY
Docket No.

SMART METER DEPLOYMENT PLAN

Direct Testimony
of
Raymond E. Valdes

<u>List of Topics Addressed</u>

Smart Meter Technologies Charge Rider
West Penn Smart Metering Settlement
Regulatory Asset for Legacy Meters
Smart Meter Surcharge Bill Presentation
Customer Requests for Smart Meters
Customer Bill Impact
Data Exchange Standards

DIRECT TESTIMONY OF RAYMOND E. VALDES

I. Introduction and Purpose of Testimony

Q. Please state your name and business address.

A. My name is Raymond E. Valdes, and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601.

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

A. I am employed by FirstEnergy Service Company as Advisor for Rates and Regulatory Affairs - Pennsylvania. FirstEnergy Service Company's Pennsylvania Rates and Regulatory Affairs Department provides regulatory support for FirstEnergy Corp.'s wholly-owned Pennsylvania electric distribution companies ("EDCs"): Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn"), each of which may be referred to as "the Company" and/or in combination as "the Companies". I report to the Director, Rates and Regulatory Affairs – Pennsylvania, and I am responsible for the development, coordination, preparation and presentation of retail tariffs; the development of retail electric rates, rules and regulations; rate and regulatory support for smart meter technology procurement and installation plans; the development and preparation of default service plans; the development and preparation of certain accounting and financial data; and the development and preparation of certain reports to the Pennsylvania Public Utility Commission ("Commission") for the Companies.

Q. What is your educational and professional background?

A. I earned a Bachelor of Science degree in electrical engineering from the University of Pittsburgh. I have nearly 22 years of experience with FirstEnergy Service Company or its predecessor companies. My work experience is more fully described in Exhibit REV-1, which is attached to my testimony.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Companies in support of the Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Phase II Smart Meter Deployment Plan. Unless otherwise stated, my testimony applies equally to all four Companies.

Q. Please describe the purpose of your testimony.

A. My testimony addresses the following elements of the Companies' proposed smart meter deployment plan ("Deployment Plan") that is the subject of this proceeding: (i) the Smart Meter Technologies Charge Rider; (ii) the West Penn Smart Metering Settlement; (iii) a request for regulatory asset treatment for the Companies' unrecovered investment in meters currently in place that will be replaced by smart meters ("Legacy Meters"); (iv) the bill presentment of the smart meter surcharge; (v) customer requests for smart meters; (vi) customer bill impacts; and (vii) data exchange standards recently ordered by the Commission.

II. Smart Meter Technologies Charge Rider

Q. What are the available methods by which smart meter technology costs may be recovered?

A. Act 129 of 2008 ("Act 129") provides that an EDC may recover smart meter technology costs through a deferral for future base rate recovery with carrying charges determined by the Commission, or on a full and current basis through a reconcilable automatic adjustment clause under Section 1307 of the Pennsylvania Public Utility Code.[1]

Q. Which cost recovery method was implemented by the Companies?

A. As permitted by Act 129 and approved by Commission orders, the Companies implemented recovery of smart meter technology costs on a full and current basis through a reconcilable automatic adjustment clause under 66 Pa. C.S. § 1307. By order entered April 15, 2010 at Docket No. M-2009-2123950, Met-Ed, Penelec and Penn Power received Commission approval to recover smart meter technology costs through a reconcilable adjustment tariff rider called the Smart Meter Technologies Charge ("SMT-C") Rider, which became effective August 1, 2010. By order entered June 30, 2011 at Docket No. M-2009-2123951,West Penn received Commission approval to recover smart meter technology costs through a reconcilable adjustment tariff rider called the Smart Meter Technologies Surcharge ("SMT-C") Rider, which became effective September 1, 2011.

[1] Codified under 66 Pa.C.S. § 2807(f)(7)

Q. Please describe the SMT-C Riders for the Companies.

A. The Commission-approved SMT-C Rider for each of the Companies consists of non-bypassable SMT-C rates designed to collect smart meter technology costs projected to be incurred during each calendar year, as well as recoup or refund, as applicable, under- or over-collections of actual smart meter technology costs from prior periods. The SMT-C rates for West Penn also collect expenditures incurred in 2009 and 2010 associated with the development of a smart meter implementation plan. The SMT-C rates are calculated separately for the residential, commercial, and industrial customer classes, and are expressed as a monthly customer charge to all metered customer accounts except for West Penn's residential customer class, which is billed on a dollar per kilowatt-hour basis. The rate schedules that comprise the residential, commercial and industrial customer classes are set forth below for each Company:

<u>Residential Customer Class</u>

Met-Ed Tariff No. 51

- Rate RS (residential service)
- Rate RT (residential time-of-day service)
- Rate GS (volunteer fire company and non-profit ambulance service, rescue squad and senior center service)

Penelec Tariff No. 80

- Rate RS (residential service)
- Rate RT (residential time-of-day service)
- Rate GS (volunteer fire company and non-profit ambulance service, rescue squad and senior center service)

Penn Power Tariff No. 35

- Rate RS (residential service)
- Rate RS (residential service with Optional Controlled Service Rider)

- Rate RH (residential service)
- Rate RH (residential service with Water Heating Option)
- Rate WH (residential controlled water heating service)
- Rate GS (special provision for volunteer fire companies, non-profit senior citizens centers, non-profit rescue squads and non-profit ambulance services)

West Penn Tariff No. 39

- Rate 10 (residential service)

<u>Commercial Customer Class</u>

Met-Ed Tariff No. 51

- Rate GS-Small (general service secondary – non-demand metered)
- Rate GS-Medium (general service secondary – demand metered)
- Rate MS (municipal service)

Penelec Tariff No. 80

- Rate GS-Small (general service secondary – non-demand metered)
- Rate GS-Medium (general service secondary – demand metered)
- Rate H (all electric school, church and hospital service)

Penn Power Tariff No. 35

- Rate GS (general service – small)
- Rate GS (general service – small with Optional Controlled Service Rider)
- Rate GS Special Rule GSDS
- Rate GM (general service – medium)
- Rate GM (general service – medium with Optional Controlled Service Rider)
- Rate WH (non-residential controlled water heating service)
- Rate PNP (public or non-profit organization service)
- Rate OH (with and without Cooling Capabilities)

West Penn Tariff No. 39

- Rate 20 (general service)
- Rate 22 (church and school service)
- Rate 23 (athletic field lighting service)
- Rate 24 (fair and carnival service)

Industrial Customer Class

Met-Ed Tariff No. 51

- Rate GS-Large (general service secondary – time-of-day service)
- Rate GP (general service – primary)
- Rate TP (transmission power service)

Penelec Tariff No. 80

- Rate GS-Large (general service secondary – time-of-day service)
- Rate GP (general service – primary)
- Rate LP (large primary service)

Penn Power Tariff No. 35

- Rate GP (general service – primary)
- Rate GT (general service – transmission)

West Penn Tariff No. 39

- Rate 30 (general power service)
- Rate 40 (primary power service)
- Rate 41 (primary power service)
- Rate 44 (interruptible primary power service)
- Rate 46 (primary power service)
- Rate 86 (alternative generation service)

West Penn Tariff No. 37

- West Penn Tariff No. 37 applies only to the Pennsylvania State University's University Park campus ("Penn State")

The Companies' street and area lighting customers are not charged an SMT-C rate since service is provided to these customers on an unmetered basis. The Commission-approved SMT-C Riders are located on pages 175 through 179 of Tariff Electric Pa. P.U.C. No. 51 for Met-Ed, pages 181 through 184 of Tariff Electric Pa. P.U.C. No. 80 for Penelec, pages 61.1 through 61.4 of Tariff Electric Pa. P.U.C. No. 35 for Penn Power, pages 5-6 through 5-8 of Tariff Electric Pa. P.U.C. No. 39 for West Penn, and pages 5-5 through 5-6 of Tariff Electric Pa. P.U.C. No. 37 for West Penn.

Q. Please describe the calculation of the SMT-C rates.

A. The SMT-C rates billed to the residential, commercial and industrial customer classes of each Company consist of two principal components. The first component is the SMT_C, which is the "current cost" projected to be incurred during each calendar year of January 1 through December 31 ("Computational Year"); and the second component is the reconciliation component, which is the "E- factor". The combination of the SMT_C and the E-factor for each customer class is divided by the projected billing determinants and grossed-up for the Pennsylvania gross receipts tax ("GRT") rate reflected in each Company's base rates in order to obtain the SMT-C rate in effect for each Company and each customer class. For all customer classes except West Penn's residential customer class, the projected billing determinants are the projected number of customers in the respective class during the Computational Year. For West Penn's residential customer class, the projected billing determinants are the projected number of distribution kilowatt-hours for the residential customer class during the Computational Year. This results in a dollar per kilowatt-hour SMT-C rate for West Penn's residential customer class and a monthly SMT-C customer charge to all other metered customer accounts in accordance with the Commission's Order entered June 30, 2011 at Docket No. M-2009-2123951 approving the *Amended Joint Petition for Settlement of All Issues* ("West Penn Smart Metering Settlement"). West Penn is not proposing to alter any of the terms of the West Penn Smart Metering Settlement.

Q. Please describe the costs that comprise the SMT_C component.

A. The SMT_C component includes projected smart meter technology costs budgeted by the Companies, such as operational and maintenance ("O&M") expenses projected to be incurred during the Computational Year, an allocated portion of indirect costs projected to be incurred during the Computational Year that benefit the respective Companies' customer classes, as well as a capital revenue requirement for capital placed in-service. SMT_C costs are reduced by measureable and sustainable reductions in O&M and avoided capital costs attributable to the implementation of smart meter technology. SMT_C costs specific to a customer class are allocated to each customer class based upon direct assignment, and general SMTC costs are allocated to each of the Companies' customer classes based upon the total number of meters in each customer class as of June immediately preceding the Computational Year. For West Penn, the SMT_C component also includes a customer class allocated collection of $40 million of expenditures in 2009 and 2010 and $5.712 million of accumulated interest associated with the development of West Penn's 2009 smart meter implementation plan. In accordance with the West Penn Smart Metering Settlement, such costs are being amortized for recovery over 5.5 years beginning with West Penn's SMT-C Rider start date of September 1, 2011.

The capital revenue requirement consists of depreciation expense and carrying charges on capital costs. The depreciation expense is the regulatory book depreciation recorded on the respective Company's books based upon the regulatory book depreciation life assigned to the asset category. The depreciation expense also includes allowance for funds used during construction ("AFUDC") accrued prior to the capital projects' in-service date. Carrying charges on capital costs is the return on capital determined from the smart metering technology net plant adjusted for accumulated deferred income taxes ("ADIT") and multiplied by the respective Company's pre-tax cost of capital. ADITs accrue to the extent that the annual tax depreciation rate differs from the annual regulatory book depreciation rate.

Q. What are the depreciation lives assigned to each asset category included in the Deployment Plan?

A. The book depreciation lives used by the Companies in the Deployment Plan are: 15 years for smart meters, 5 years for hardware and 7 years for software. The regulatory book lives were determined based upon input from external sources and internal/external subject matter experts. The Companies used tax depreciation lives based on guidance from the Internal Revenue Service.

Q. How do the book depreciation lives included in the Deployment Plan compare to the book depreciation lives in the West Penn Smart Metering Settlement?

A. The West Penn Smart Metering Settlement provides for a 15-year regulatory book life for smart meters and a 5-year regulatory book life for hardware, which matches the Companies' proposed depreciation lives. However, the West Penn Smart Metering Settlement provides for a 10-year regulatory book life for software, whereas the Companies have used a 7-year regulatory book life for software in order to reflect current expectations. Since West Penn is not proposing to alter any of the terms of the West Penn Smart Metering Settlement, software that was capitalized by West Penn for Phases 1 through 3 of the West Penn Smart Metering Settlement will continue to have a 10-year regulatory book life, while other software capitalized by the Companies will utilize a 7-year regulatory book life.

Q. What capital structure and cost rates are used to determine the cost of capital?

A. Met-Ed, Penelec and Penn Power are utilizing a capital structure and cost rates in accordance with Commission order entered April 15, 2010 at Docket No. M-2009-2123950. Since Met-Ed's, Penelec's and Penn Power's last litigated base rate case is more than three years old, these Companies henceforth will use their respective actual capital structure ratios included in the then most recent Commission Report on the Quarterly Earnings of Jurisdictional Utilities ("Quarterly Earnings Report").[2] For the quarterly costs of debt and preferred stock, these Companies will use their respective rates in the then most recent Quarterly Earnings Report. For the quarterly return on equity ("ROE"), these Companies will use the rate for the electric utility barometer group included in the then most recent Quarterly Earnings Report.[3]

West Penn's capital structure and cost rates were set in the West Penn Smart Metering Settlement. Therefore, consistent with the West Penn Smart Metering Settlement, West Penn has used its actual capital structure, the quarterly costs of debt and preferred stock

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[2] If the last litigated base rate case is less than three years old, the capital structure ratios from that base rate case will, instead, be used. If the last litigated base rate case is more than three years old and the actual capital structure for Met-Ed, Penelec or Penn Power from the Quarterly Earnings Report is outside the zone of reasonableness for the electric utility industry (as provided in the Quarterly Earnings Report), the capital structure ratio for the affected Company will be the average of the electric utility barometer group included in the then most recent Quarterly Earnings Report.

[3] If the last litigated base rate case is less than three years old, the ROE from that base rate case will, instead, be used.

included in its Quarterly Earnings Report, and a 10% ROE for purposes of calculating the SMT-C capital revenue requirement.[4]

Q. Please explain the E-factor reconciliation component.

A. The E-factor component of each of the Companies' residential, commercial and industrial customer class-specific SMT-C rates represents a reconciliation of actual smart meter technology costs incurred by customer class to actual SMT-C revenues (excluding GRT) by customer class. Actual smart meter technology costs are the actual O&M costs, indirect costs, and capital revenue requirement, along with a credit for actual measurable O&M and avoided capital savings, booked by each of the Companies each month. Actual SMT-C revenues are the SMT-C Rider revenues booked by each of the Companies each month, as adjusted for removal of the E-factor and GRT reflected in each Company's base rates. The reconciliation calculated monthly for each Company results in either an over- or under-collection of costs by customer class. Each month, by specific customer class for each Company, interest is calculated from the month the over- or under-collection occurs until the month that the over-collection is refunded or the under-collection is recovered from customers in each specific customer class. Interest is calculated at the legal rate of interest determined pursuant to 41 P.S. § 202. The cumulative net balance per customer class, including interest, as of June 30th immediately preceding the Computational Year, is then included for recovery (in the case of an under-collection) or refund (in the case of an over-collection) in the customer class specific SMT-C rates calculated for the forthcoming Computational Year.

[4] West Penn is to use a 10% ROE until West Penn is authorized to implement a new ROE as part of a base rate case or a different ROE is authorized as part of the revised Deployment Plan proceeding.

Q. When are SMT-C rate changes filed with the Commission?

A. SMT-C rates for the Companies are filed with the Commission by August 1st of each year, to be effective the forthcoming January 1st. As previously mentioned, the SMT-C rate filing includes the SMT_C costs projected to be incurred during the Computational Year, an adjustment resulting from the E-factor reconciliation component, and an adjustment for GRT reflected in each Company's base rates. However, upon determination that the SMT-C rates would result in a material over- or under-collection of smart meter technology costs incurred, or expected to be incurred, during the Computational Year, the Companies may request that the Commission approve an interim revision to the SMT-C rates to be effective 30 days from the date of filing, unless otherwise ordered by the Commission in accordance with their SMT-C Riders.

Q. Are any reports filed with the Commission regarding the SMT-C Rider?

A. Yes. The Companies each file an annual report of collections under their respective SMT-C Rider within 30 days following June 30th. The reconciliation report is in accordance with the provisions under 66 Pa. C.S. § 1307, and is subject to review and audit by the Commission.

Q. Do the Companies propose to recover the costs incurred as a result of the implementation of the Deployment Plan through their respective SMT-C Riders?

A. Yes. The SMT-C Rider for each Company has been approved by the Commission for recovery of smart meter technology costs and is the appropriate vehicle to continue recovery of current and future smart meter technology costs. Deployment Plan costs that are the subject of this proceeding will be reflected in the previously discussed annual update to the SMT-C Riders and collected through the SMT-C rates.

Q. Are the Companies proposing any modification to the existing SMT-C Riders?

A. No. The Companies are not proposing any revision to any portion of the SMT-C Riders already approved by the Commission aside from a text revision to the West Penn SMT-C Riders to reflect collection of an additional $5.1 million, as described later in my testimony.

Q. Why haven't the Companies proposed a uniform SMT-C rate design for the residential customer class?

A. A monthly customer charge rate design for the residential customer classes of Met-Ed, Penelec and Penn Power was approved by Commission Order entered April 15, 2010 at Docket No. M-2009-2123950, wherein the Commission stated that "…to provide recovery of these costs through a monthly customer charge is consistent with our decision to allocate these same costs on a 'per meter' basis. Additionally, as cost savings are realized by the Companies and reflected in the fixed monthly charge, the ratepayers will be able to see that specific change on their bills. Such a reduction may not be as evident to customers if contained within a volumetric or usage rate."[5] Although West Penn originally proposed a similar monthly customer charge rate design for its residential customer class, it agreed in the West Penn Smart Metering Settlement to a per kilowatt-hour rate design solely for the residential customer class. Since West Penn is not proposing to alter any of the terms of the West Penn Smart Metering Settlement, it is

[5] Order at 51.

continuing to abide by the residential class rate design agreed upon in the West Penn Smart Metering Settlement, but would not be opposed to a proposal to change West Penn's residential class SMT-C rate design to a monthly customer charge that is similar to that of the other Companies.

III. <u>West Penn Smart Metering Settlement</u>

Q. Are there any outstanding cost recovery issues regarding the West Penn Smart Metering Settlement?

A. Yes. The West Penn Smart Metering Settlement recognized that West Penn expended approximately $45.1 million in 2009 and 2010 associated with the development of its smart meter implementation plan. Of this amount, the settling parties agreed that initially $40 million could be recovered through the SMT-C Rider with interest. Although the additional $5.1 million was related to the smart meter implementation plan, recovery through the SMT-C Riders was questioned by the settling parties. However, the West Penn Smart Metering Settlement permitted West Penn to file for recovery of the $5.1 million amount in its next distribution base rate case and/or as part of the SMT-C Rider in connection with its revised Deployment Plan filing.

Q. Is West Penn requesting recovery of the additional $5.1 million in this proceeding?

A. Yes. West Penn is requesting Commission approval to include the additional $5.1 million with the current Commission-approved $40 million, for a total recovery of 2009 and 2010 costs of $45.1 million. Upon Commission approval, the $5.1 million would be recovered over the balance of the 5.5-year amortization period previously approved by the Commission for recovery of the initial $40 million, or through February 28, 2017.

Since the 5.5-year recovery period of the $40 million began on September 1, 2011, it will conclude on February 28, 2017. Therefore, if the Commission approves recovery of the additional $5.1 million and enters its final Order in September 2013, West Penn will book the monthly amortized recovery expense effective with Commission approval and continue doing so through the remaining life (i.e., through February 28, 2017), with reconciliation and rate recovery reflected in the regularly scheduled SMT-C rate change. West Penn's SMT-C Riders would be amended through a compliance filing to reflect recovery of $45.1 million rather than $40 million. The additional $5.1 million will be allocated to each of West Penn's customer classes on the same basis as the previously approved $40 million, which is based upon the number of meters in each customer class as of June immediately preceding the Computational Year.

Q. What is the justification for requesting approval of the additional $5.1 million?

A. The West Penn Smart Metering Settlement provided for recovery of $40 million of prior expenditures incurred while West Penn was developing its 2009 Smart Meter Technology Procurement and Implementation Plan. The additional $5.1 million was not initially included for recovery because certain settling parties questioned whether those dollars should be recovered through the SMT-C Rider, believing that amount might relate to a general updating of West Penn's Customer Information System ("CIS"). However, the additional $5.1 million of CIS-related costs were an unavoidable expenditure inextricably related to the costs West Penn incurred as part of the development of its 2009 plan since: (i) West Penn's CIS was not capable of supporting smart meters; and (ii) these expenditures, including CIS expenditures, would not have occurred absent the Act 129 mandate and could not have been avoided once it was necessary to update the CIS system to enable smart meters. This conclusion was reinforced in Administrative Law Judge ("ALJ") Mark A. Hoyer's Initial Decision dated April 29, 2010 at Docket No. M-2009-2123951, wherein he concluded that back office costs (which included CIS costs) were recoverable within the purview of Act 129 and through a surcharge.[6] Although the ALJ's Initial Decision was never ruled upon by the Commission due to the introduction of the West Penn Smart Metering Settlement, the conclusions reached by the ALJ, based upon a full evidentiary record, are viable and persuasive nonetheless. Full recovery of the $45.1 million, which includes the $5.1 million, is also justified because the Phase I and Phase II deliverables of the West Penn Smart Metering Settlement have proven to be useful and valuable in the smart metering design solution. The $7.3 million Phase I development of requirements, designs, vendor analysis and cost analysis was useful during the Grace Period in providing templates for process design and business case modeling. The $37.8 million Phase II development of process designs, technical and functional designs, change management plans, data conversion, security system and project management office estimates was useful during the Grace Period in offering templates for how to model aspects of the technology systems for the Deployment Plan and validating work done by the PA Companies. Also, the Phase I and Phase II work done by West Penn supported the its ability to deploy the approximately 25,000 Phase III meters that enabled West Penn's Energy Saver Rewards Program. Act 129 defines smart meter technology as "…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*".[7]

[6] Initial Decision at 50.
[7] 66 Pa.C.S. § 2807(g)

[emphasis supplied]. Consistent with that definition, West Penn is requesting full recovery of the entire $45.1 million of costs incurred in 2009 and 2010 associated with the development of a smart meter deployment plan. In summary, West Penn is requesting that it be allowed to include an additional $5.1 million with the previously approved recovery of $40 million, to be collected over the balance of the existing amortization period and concluding on February 28, 2017.

IV. <u>Regulatory Asset for Legacy Meters</u>

Q. How do the Companies propose to recover the remaining costs associated with Legacy Meters being replaced with smart meters?

A. The Companies propose to retire the Legacy Meters out of stock, continue the existing depreciation schedule without modification over the remaining lives of the metering asset, and continue cost recovery through base rates.

Q. Are the Companies requesting authorization for specific accounting treatment associated with the Legacy Meters?

A. Yes. The Companies are requesting an approach that would allow fair cost recovery of the Legacy Meters through the Commission's approval to create a regulatory asset for the Legacy Meters, with a recovery schedule set equal to the remaining depreciable lives of such meters per the respective Company's Annual Depreciation Reports as filed with and approved by the Commission pursuant to 52 Pa. Code §§ 73.1-73.9, and continued recovery through base rates. Salvage value received from the disposition of Legacy Meters will be used as an offset to the regulatory asset, similarly amortized over the remaining depreciable lives of the metering asset. The rate base equivalent of the regulatory asset for Legacy Meters will continue to be included in the respective Company's rate base and will not result in any net change to customer base rates. However, the Companies may consider altering the length of the recovery schedule in a future distribution rate case.

Q. How will the cost of removing the Legacy Meters be accounted for?

A. The removal of the Legacy Meters is part of the installation of the smart meters. Therefore, the Companies request Commission approval to include the cost of removal for Legacy Meters as a recoverable O&M expense in the SMT_C of each Company's SMT-C Rider.

V. Smart Meter Surcharge Bill Presentation

Q. How is the SMT-C currently presented on customer bills?

A. For all metered customers of the Companies, the SMT-C is currently displayed as a separately stated line item entitled "Smart Meter Charge".

Q. Are the Companies proposing any changes to the presentation of the SMT-C on customer bills?

A. Yes. Instead of being listed as a separately stated line item, the Companies propose that the SMT-C charge be included within the distribution charge on customer bills.

Q. Why are the Companies proposing such a change?

A. The Companies' distribution charges currently include charges for metering and meter reading. The SMT-C is simply a smart metering extension of the Companies' obligation to provide metering and meter reading. Since the Companies' existing metering and meter reading costs are not a separately stated charge on the customer's bill, there is no reason to continue listing the SMT-C as a separately stated line item on the customer's bill. Metering, regardless of whether it's for Legacy Meters or smart meters, is performed by the EDC as part of its base distribution service and should be reflected as such when presented on customer bills. In fact, since 66 Pa. C.S. § 2807(f)(7) provides an option for recovery of smart meter technology costs through base rates, it appears to be a logical conclusion that recovery of such costs should be presented on the customer's bill under a distribution function, which is identified on customer bills as the distribution charge.

Q. Do other electric utilities include their smart meter charge in the distribution charge for bill presentation purposes?

A. Yes, Duquesne Light Company, PECO Energy Company, and PPL Electric Utilities Corporation all have included their version of the smart meter charge in their respective distribution charge for bill presentation purposes. Since none of the other electric utilities covered by Act 129 have a separately stated smart meter charge on their bills, the proposal by the Companies to include the SMT-C in the distribution charge for bill presentation purposes will provide consistency throughout the Commonwealth for all affected EDCs.

Q. Are any other separately calculated charges included in the distribution charge for bill presentation purposes?

A. Yes. Consistent with prior Commission approvals regarding 66 Pa. C.S. § 1307 cost recovery mechanisms for universal service and Act 129 energy efficiency and conservation programs, the Companies include the Universal Service Cost Charge in the distribution charge for all customers[8] and the Energy Efficiency & Conservation Charge in the distribution charge for residential customers. In approving inclusion of the Energy Efficiency & Conservation Charge in the distribution charge, the Commission stated that "distribution rates [are] the appropriate vehicle to incorporate rolled up cost-centers or to recover the costs of providing service that is not otherwise classified as transmission or generation."[9]

Q. Will any charges be affected by the Companies' proposal?

A. No. All charges, such as the base distribution charge and the SMT-C in each Company's tariff, will be unaffected by the Companies' proposal. Revenues associated with the base distribution charge and the SMT-C will continue to be separately recorded and tracked on the Companies' books. The SMT-C will also continue to be separately calculated for each of the Companies' customer classes, as previously discussed. In short, there will be no net change to the charges billed to customers on a monthly basis. The only difference

[8] West Penn's universal service costs are currently collected as part of its distribution rates and are not listed as a separate charge in its retail tariffs.

[9] *See* Order at page 88, *Petition of West Penn Power Company for Approval of its Energy Efficiency and Conservation Plan, Approval of Recovery of its Costs through a Reconcilable Adjustment Clause and Approval of Matters Relating to the Energy Efficiency and Conservation Plan*, Docket No. M-2009-2093218, entered October 23, 2009.

is that instead of listing the Smart Meter Charge separately from the distribution charge, both charges will be combined in the distribution charge for bill presentation purposes.

VI. Customer Requests for Smart Meters

Q. What are the requirements to install smart meters for new construction and for customer requests?

A. In the Smart Meter Implementation Order entered June 24, 2009 at Docket No. M-2009-2092655, the Commission established a 30-month Grace Period for EDCs to conduct an assessment of needs and technological solutions, select technologies and vendors, and undertake other activities and planning for smart meter network build-out and deployment. Following the Grace Period and during network build-out, EDCs are required to supply smart meters for all new construction that is begun after the Grace Period and to customers who request a smart meter prior to the build out of the network in their neighborhood ("Early Adopters"), provided that these customers pay the incremental costs of doing so. The Grace Period for each of the Companies will end on December 31, 2012.[10]

Q. Have the Companies filed for Commission approval of recovery of these incremental costs?

A. Yes. On October 31, 2012, the Companies filed tariff revisions to include the incremental cost of smart meters and related installation costs to be charged to Early

[10] *See* Secretarial Letter, *Met-Ed/Penelec/Penn Power SMIP Proceedings* and *West Penn SMIP Proceedings* (filed June 28, 2012). Following the merger of FirstEnergy Corp. and Allegheny Energy, Inc., which resulted in West Penn becoming a FirstEnergy Pennsylvania EDC and an affiliate of Met-Ed, Penelec, and Penn Power, the Companies have proceeded to develop a single, combined SMIP. *See* West Penn Power Company's Revised Smart Meter Technology Procurement and Installation Plan Compliance Filing (filed August 31, 2011).

Adopters. The tariff revisions were approved by Commission Secretarial Letters dated December 21, 2012 at Docket Nos. R-2012-2332803, R-2012-2332776, R-2012-2332785, and R-2012-2332790. The effective date of the tariff revisions is January 1, 2013.

VII. Customer Bill Impact

Q. Have the Companies calculated the estimated customer bill impact associated with the Deployment Plan?

A. Yes. On August 1, 2012, the Companies filed proposed SMT-C rates to be effective January 1, 2013, along with supporting details of the computation.[11] By Secretarial Letter dated December 14, 2012, the proposed rates were approved. The 2013 SMT-C rates by customer class for each of the Companies are provided below:

Residential Customer Class

- Met-Ed = $0.96 per month
- Penelec = $0.95 per month
- Penn Power = $0.91 per month
- West Penn = $0.00276 per kilowatt-hour

Commercial Customer Class

- Met-Ed = $0.96 per month
- Penelec = $0.97 per month
- Penn Power = $1.01 per month
- West Penn = $2.43 per month

Industrial Customer Class

- Met-Ed = $1.05 per month
- Penelec = $0.95 per month

[11] On August 27, 2012, West Penn refiled its proposed SMT-C rates effective January 1, 2013 to reflect an update to its Reconciliation Statement of Revenues and Expenses for the reconciliation year ended June 30, 2012.

- Penn Power = $0.95 per month
- West Penn = $2.03 per month

The percentage impact on a customer's total bill is difficult to provide with precision for two primary reasons. First, a large portion of a customer's bill is dictated by generation prices, which in terms of default service changes as frequently as quarterly for the residential and commercial customer classes and hourly for the industrial customer class. Second, generation prices are not necessarily known for customers receiving service from an electric generation supplier ("EGS"). However, using an average residential usage of 1,000 kilowatt-hours per month and a residential total rate of approximately 10 cents per kilowatt-hour, the above residential SMT-C rates equate to the approximate percentage impact. For example, the Met-Ed residential customer class rate of $0.96 per month would equate to an approximate 0.96% impact, while the West Penn residential customer class rate of $0.00276 per kilowatt-hour would equate to an approximate 2.76% impact based upon an average usage of 1,000 kilowatt-hours per month. The percentage impact to the commercial and industrial customer classes will be substantially less than the percentage impact to the residential customer class since average commercial and industrial customers use substantially more energy than an average residential customer, but have a SMT-C rate as a fixed value per month that is not dependent upon the volume of energy consumption.

Q. What is the projected impact of future changes to the SMT-C rate?

A. The impact of future SMT-C rate changes will be dependent upon the projected smart meter technology costs budgeted by the Companies, as adjusted by the E-factor to reconcile actual smart meter technology costs incurred to actual SMT-C revenues (excluding GRT). Chapter 5 of the Deployment Plan sets forth projected monthly billing impacts for each customer class for the investment in smart meter technology.

VIII. Data Exchange Standards

Q. Has the Commission provided any recent directives regarding data exchange standards in smart meter plans?

A. Yes. By Order entered December 6, 2012 at Docket No. M-2009-2092655, the Commission established data exchange standards for current business processes. Specifically, the Commission directed that all EDCs subject to the smart meter provisions of Act 129 address standards for attaining real-time ("RT") and time-of-use ("TOU") pricing capabilities, provide the EDC's current capability to provide a minimum of 12-months of historical interval usage data via electronic data interchange ("EDI"), and to incorporate meter-level interval usage data capabilities.

Q. What did the Commission direct with regard to attaining RT and TOU pricing capabilities?

A. The Commission concluded that bill ready and dual billing capabilities present the best option for attaining RT and TOU pricing capabilities, and directed that all EDCs subject to the smart meter provisions of Act 129 propose bill ready and dual billing functionalities as part of their smart meter plans.

Q. Do the Companies have such functionality in place?

A. Yes. If a customer elects service on a RT or TOU pricing option under a dual billing scenario, an EGS would use an existing EDI 814 enrollment transaction and specify that it will calculate and bill its own charges. Similarly, if a customer elects service on a RT or TOU pricing option under a bill ready EDC-consolidated billing option, an EGS would use an existing EDI 814 enrollment transaction and specify that it will calculate its own charges to be consolidated with the bill produced by the EDC. Since the Companies' enrollment and billing system is currently programmed to accept dual billing and bill ready EDC-consolidated billing, such Commission-directed functionality is currently in place and in use by the Companies.

Q. What did the Commission direct with regard to providing historical interval usage data via EDI?

A. The Commission addressed this issue separately for pre-smart meter implementation and post-smart meter implementation. For pre-smart meter implementation, the Commission directed all EDCs subject to the smart meter provisions of Act 129 to install the capability to share a minimum of 12 months of historical interval account-level or meter-level usage via EDI. Such EDCs must file within 120 days a supplement outlining the EDC's current capability to provide interval usage data via EDI or the EDC's plans to provide this capability within one year. For post-smart meter implementation, the Commission directed the Electronic Data Exchange Working Group to initiate a working group to develop a standardized solution for the acquisition of interval usage data via a secure web-portal.

Q. Are the Companies currently able to provide interval usage data via EDI?

A. Yes. The Companies are able to use the EDI 867 Historical Interval Usage transaction to transmit a minimum of 12 months of historical interval usage. As such, in lieu of filing a supplement within 120 days, the Companies are able to state that they currently meet the Commission's pre-smart meter implementation directive to provide interval usage data via EDI.

Q. What did the Commission direct with regard to incorporating interval usage data capabilities?

A. The Commission directed all EDCs to incorporate meter-level (as opposed to account-level) interval usage data capabilities within their respective smart meter plan.

Q. How do the Companies define account-level versus meter-level?

A. For the Companies, the account-level and meter-level are generally the same because it is common practice to provide a delivery point through a single meter at one supply voltage. There are rare legacy installations that may have more than one meter at more than one supply voltage. However, for such rare installations, the Companies currently provide usage data for the separate meter and supply voltage. There are other rare installations where multiple meter readings are totaled for billing purposes. In such situations, billing is not provided for any of the individual meters since the aggregate meter data is used for billing all EDC charges in accordance with the Commission-approved tariff, as well as other functions such as scheduling and EGS enrollments. In such rare installations, the aggregate meter data should be considered "meter-level" since billing, scheduling and enrollments are not provided for each individual meter, but are instead provided only on an aggregate basis.

Q. What did the Commission conclude regarding aggregate meter data?

A. In its Order, the Commission accepted the concept of aggregate meter data for meter-level data. Therefore, the Companies currently incorporate meter-level interval usage data as directed by the Commission.

Q. Does this complete your direct testimony?

A. Yes, it does, but I reserve the right to file such other testimony as may be necessary or appropriate.

Exhibit REV-1

Resume: Education and Experience of Raymond E. Valdes

Education:

1990	Bachelor of Science Degree in Electrical Engineering University of Pittsburgh

Experience:

1991 – 1996	Power Services Engineer – Allegheny Energy Service Corporation
1996 – 1999	Engineer, Rates – Allegheny Energy Service Corporation
1999 – 2005	Regulatory Specialist – Allegheny Energy Service Corporation
2005 – 2007	Senior Consultant – Allegheny Energy Service Corporation
2007 – 2011	General Manager, Retail Pricing Services – Allegheny Energy Service Corporation
2011 – present	Advisor – FirstEnergy Service Company

Prepared and presented testimony in the following rate-related cases:

Pennsylvania Public Utility Commission Cases:

Docket Nos.	P-00072349
	R-00072753
	R-00072754
	P-00072342
	P-2008-2021608
	M-2009-2093218
	M-2009-2123951
	P-2010-2158084
	M-2011-2237573
	P-2011-2218683
	P-2011-2224781
	P-2011-2273650
	P-2011-2273668
	P-2011-2273669
	P-2011-2273670

Pennsylvania Senate:

Pennsylvania Senate Consumer Protection and Professional Licensure Committee
November 20, 2007

Maryland Public Service Commission Cases:

Case Nos.	8738
	8797
	8908
	9037
	9056
	9064
	9091
	9111
	9153
	9166
	9175
	9228
	9233

West Virginia Public Service Commission Cases:

Case No.	06-0960-E-42T
	09-1352-E-42T
	11-0452-E-PC

Ohio Public Utilities Commission Cases:

Case No.	04-1047-EL-ATA
	05-765-EL-UNC

Virginia State Corporation Commission Case:

Case No.	PUE-2007-00085