BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. M-2013-2341990

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. M-2013-2341994

PENNSYLVANIA POWER COMPANY
DOCKET NO. M-2013-2341993

WEST PENN POWER COMPANY
DOCKET NO. M-2013-2341991

SMART METER DEPLOYMENT PLAN

ORIGINAL DECEMBER 31, 2012
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TABLE OF CONTENTS

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,

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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.

entered into an Amended Joint Petition for Settlement ("Joint Settlement") in 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

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.

improved technology occurred during the second half of 2012 and the results were assessed as part of the technology selection process, which is more fully discussed in Chapter 2.

In the interim between the completion of the evidentiary hearing in May 2013 and the release of the Administrative Law Judge's Recommended Decision in November 2013, the Companies continued testing the selected end-to-end smart meter solution. Based upon these test results the Companies believe that it is now possible to accelerate the deployment of Smart Meters beyond that originally proposed in the deployment plan ("Original Deployment Plan" or "Deployment Plan"). This Deployment Plan has been revised to reflect this accelerated schedule ("Revised Deployment Plan").

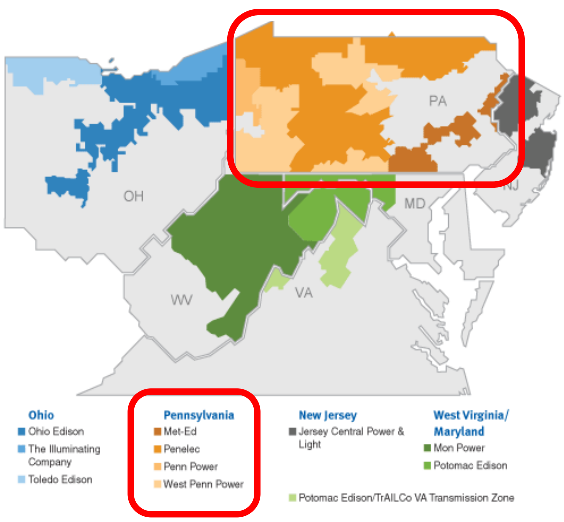
This Revised Deployment Plan is based upon the most current available information and sets forth a plan that will accelerate the installation of smart meters, with all of Penn Power's customers receiving smart meters by the end of 2015, and approximately 98.5 percent of all customers within the FirstEnergy Pennsylvania footprint receiving smart meters no later than mid-2019, with the remaining remote customers receiving meters no later than 2022. The projected cost of this Revised Deployment Plan is still approximately $1.258 billion over a 20 year life cycle of the project on a nominal dollar basis, and approximately $608 million on a net present value ("NPV") basis after netting estimated potential operational cost savings of approximately $142 million (NPV). Approximately $815 million (nominal) will be spent during the six year construction and meter deployment period that is expected to start on July 1, 2014 and conclude prior to the end of 2019 ("Deployment Period"), assuming the Commission approves this Plan by June 30, 2014.

Chapter 2 explains in more detail the work performed to develop the Original and Revised Deployment Plans. Chapter 3 describes the recommended solution and its compliance with Act 129 and Commission directives. Chapter 4 addresses the cost of implementing the Revised Deployment Plan, the estimated savings that the Companies and their customers 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.

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%

[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.

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. During the period between the filing of the Original Deployment Plan and the issuance of the Administrative Law Judge's Recommended Decision, the Companies continued testing the selected end-to-end solution. Based upon the results of this testing, the Companies now believe that, absent unforeseen events, the deployment schedule as originally proposed ("Original Deployment Schedule"), can be modified to (i) build out the entire Penn Power end-to-end solution, instead of only installing 60,000 meters; and (ii) accelerate the completion of the Solution Validation Stage and the commencement of the Full-Scale Deployment Stage by one year ("Accelerated Deployment Schedule"). This schedule is further summarized in Section 1.6.

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.

[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.

Contract Negotiation/RFPs: During the period between the filing of the Original Deployment Plan with the Commission on December 31, 2012 and the submission of this Revised Deployment Plan, the SMIP Team selected a Systems Integrator ("SI") and Project Management Office ("PMO") consultant through the RFP process described in Chapter 2, and negotiated final terms and conditions with all key vendors. Further the SMIP Team worked with consultants and selected vendors to develop construction schedules, all with the goal to have everything in place to start construction of the infrastructure upon approval of this Revised 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 "Penn Power end-to-end version" of the Companies' comprehensive Pennsylvania end-to-end smart meter solution will be constructed and tested prior to full scale deployment. Specifically, this stage is expected to start in mid-2014 and continue until the end of 2015. Instead of installing 60,000 meters during this stage, as was originally contemplated, the Revised Deployment Plan anticipates the complete build out of Penn Power (approximately 170,000 smart meters and supporting end-to-end infrastructure) during this period.

- *Build-Out Activities*. This period begins upon Commission approval of this Revised Deployment Plan and will continue for approximately 18 months. During this period, the Companies will commence construction of the smart meter solution infrastructure, or "backbone" for the Penn Power "mini system". This will involve the installation of meters, collectors, range extenders, network communications, and meter data management systems for testing.

- *Solution Testing Activities*. As the infrastructure is built out, the Companies will 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 50,000 meters will be installed in 2014 and another 120,000 in 2015, in order to allow for the testing of scalability and the resolution of communication, functionality and installation problems encountered in a contained and controlled environment, thus minimizing costs of overall deployment and customer frustration. Only after all such problems are resolved will the Companies commence the final Full-Scale Deployment Stage, which is currently anticipated to commence in early 2016.

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, initially at an average rate of 1,900 meters per day, five days per week, with the potential to accelerate deployment to as many as 3,000 meters per day, should circumstances and conditions warrant. At this pace, the Companies expect to install approximately 98.5% of all meters between January 1, 2016 and mid-2019, with the remaining 1.5% of the meters being installed thereafter through December 31, 2022[7]. This 1.5 % of the installations represent those installations that may require alternative communication solutions or difficult to reach locations such as remote hunting cabins. Any similar situations discovered in Penn Power's service territory are included in this estimate of 1.5% and will be addressed in the time frame discussed above.

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 the Original Deployment Plan as well as the potential verifiable savings that may be realized through the installation of smart meter technology. Thus, certain inputs have been modified to reflect the Accelerated Deployment Schedule, the results of which are set forth in this Revised Deployment Plan. There are potentially other benefits that may accrue directly to customers that have not been taken into account in this analysis. These customer benefits are addressed in Chapter 4.

[7] While the Companies originally anticipated an average installation rate of 3,000 meters per day, based upon subsequent discussions with meter installation vendors, it was recommended that installation be paced at 1,900 meter per day and ramped up over time if appropriate.

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 Years)

	Total PA	Met-Ed	Penelec	Penn Power	WPP
Capital Costs	$ 667,390,350	$ 181,338,201	$ 192,354,386	$ 60,847,753	$ 232,850,010
O&M Costs	$ 590,204,938	$ 162,940,051	$ 172,612,059	$ 46,040,407	$ 208,612,421
Total Costs	$ 1,257,595,288	$ 344,278,252	$ 364,966,445	$ 106,888,160	$ 441,462,431
Total Savings	$ 417,023,753	$ 102,911,556	$ 124,772,459	$ 34,358,311	$ 154,981,427

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

Like the Original Deployment Plan, costs associated with this Revised 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 the Revised Deployment Plan is in effect:

Figure 1.3 Monthly Bill Impacts (Nominal)[8]

Op Co	Residential		Commercial		Industrial	
	Range	Average	Range	Average	Range	Average
Met-Ed	$0.91 - $4.59	$2.36	$0.96 - $5.27	$2.89	$1.05 - $6.24	$3.52
Penelec	$0.44 - $5.30	$2.56	$0.47 - $6.35	$3.09	$0.78 - $8.15	$4.13
Penn Power	$0.76 - $4.50	$2.26	$0.76 - $4.50	$2.72	$0.95 - $6.10	$3.35
West Penn	$0.70 - $4.92	$2.64	$1.09 - $5.73	$3.27	$2.03 - $6.73	$4.30

Additional details are set forth in Chapter 5.

[8] 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

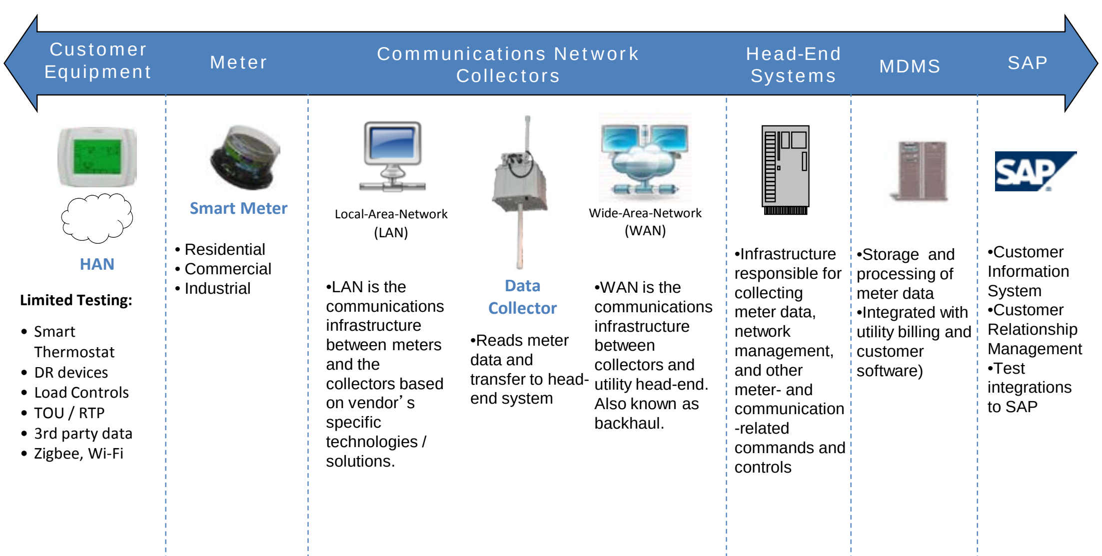
The integration of smart meters and supporting technologies is known as Advanced Metering Infrastructure ("AMI"). AMI enables bidirectional communication, records customer consumption hourly (or more frequently), and provides for transmittal of meter readings over a communication network to a central 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.

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.

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.

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.

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

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

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.

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. 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

Between the completion of the evidentiary hearing in May 2013 and the release of the Administrative Law Judge's Recommended Decision in November 2013, the Companies continued testing the end-to-end solution that was to be implemented during the Solution Validation Stage. Based on the results of this testing, the Companies now believe they can accelerate the deployment of smart meters in Penn Power's service territory and completely build out Penn Power by the end of 2015, rather than only install 60,000 smart meters as originally proposed.

Consistent with the Deployment Plan, the Companies also began negotiations with all major vendors during the period between the close of the evidentiary hearing and the end of 2013. Based on these negotiations, the Companies have in place the contracts necessary to complete this accelerated build out as described in this Revised Deployment Plan.

CHAPTER 3. SMART METER SOLUTION AND DEPLOYMENT STRATEGY

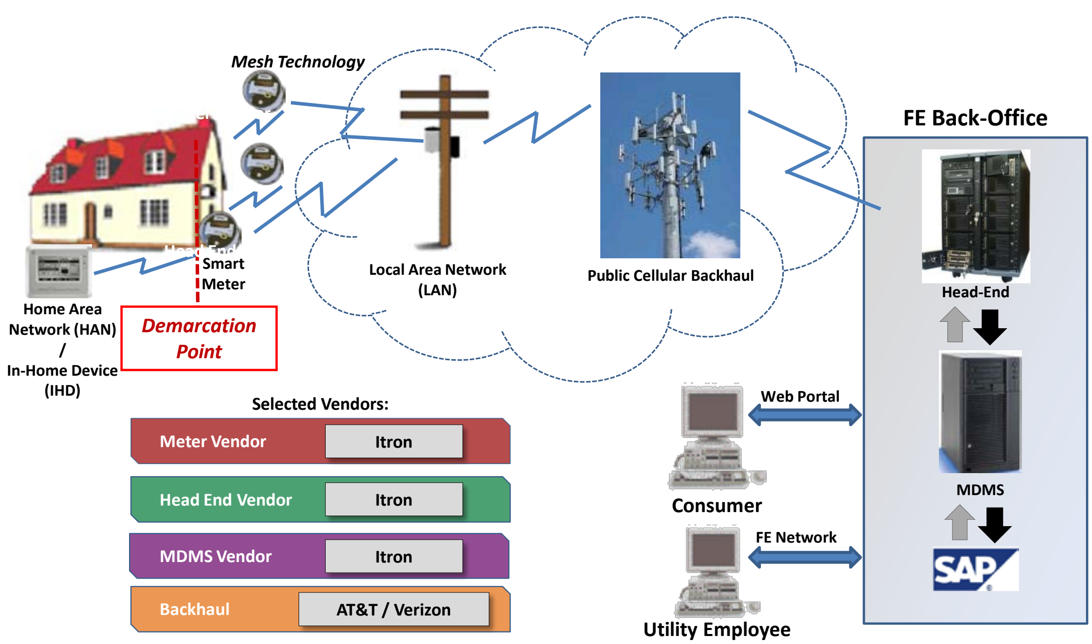
3.1 Overview

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 mid-2019 ("Deployment Period"), with the remaining 1.5% of the meters being installed thereafter through December 31, 2022. The Companies will build out Penn Power's system (approximately 170,000 meters) during the Solution Validation Stage. Thereafter, Full-Scale Deployment will commence and continue until all smart meters are installed.

The Original Deployment Plan contemplated an average of 3,000 meters per day, five days per week. After discussions with installation vendors, the initial average installation rate will be paced at approximately 1,900 meters per day, five days per week, with the potential to accelerate such deployment to as many as 3,000 meters per day, five days per week should circumstances and conditions warrant[9]. 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.

[9] Savings and cost estimates are conservatively based upon a constant installation rate of 1,900 meters per day, five days per week.

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.

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.[10]

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

[10] 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.

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.
- 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,[11] 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.[12] 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.

[11] 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.

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

Contract Negotiation/RFPs: During the period between the filing of the Deployment Plan with the Commission and approval of the plan by the Commission, the SMIP Team negotiated final terms and conditions with the selected vendors, selected a systems integrator ("SI") and project management office ("PMO") through the RFP process described in Chapter 2, finalized contracts with the SI and PMO and worked 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 Revised 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 will begin with the installation of all smart meters and supporting infrastructure in the Penn Power service territory. This stage is expected to start in mid-2014 and continue until late 2015.

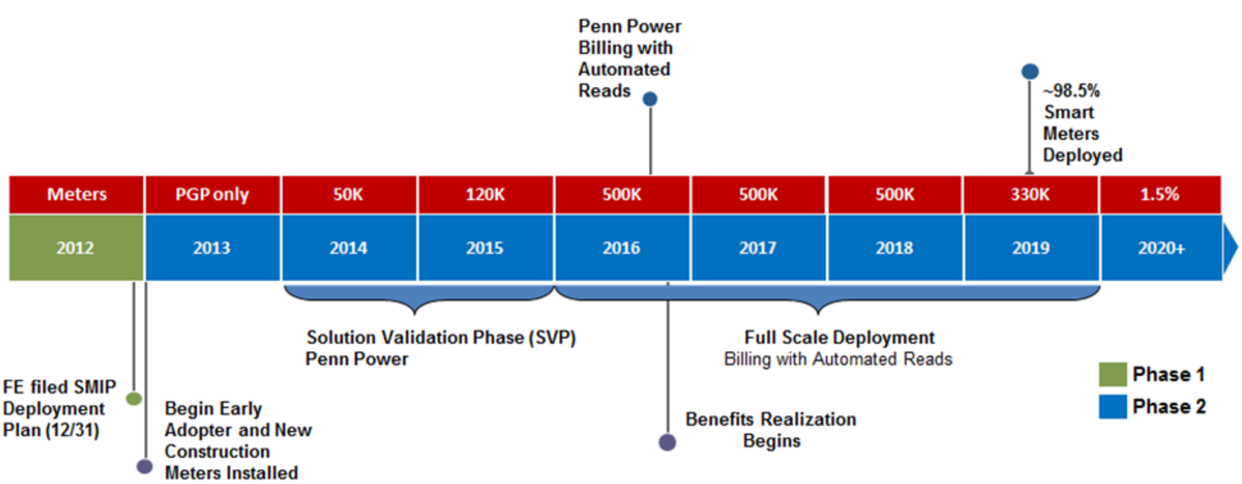
- *Build-Out Activities*. This period begins upon Commission approval of this Deployment Plan and will continue for approximately 18 months. During this period, the Companies will commence and complete construction of the smart meter solution infrastructure, or "backbone" for the Penn Power service territory. This will involve the installation of meters, collectors, range extenders, network communications, and meter data management systems for testing.

- *Solution Testing Activities*. As the infrastructure is built, the Companies will install meters in Penn Power's service territory. This territory was selected because it includes the wide range of challenges the SMIP Team anticipates encountering during full deployment across all of the Companies. Approximately 50,000 meters will be installed in the second half of 2014 and the remaining 120,000 will be installed in 2015, 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 Full-Scale Deployment Stage, currently anticipated to commence in early 2016.

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 meter installation rate of 1,900 meters per day, five days per week, and potentially ramping up to 3,000 meters per day if circumstances and conditions warrant. At this pace, the Companies expect to install approximately 98.5% of all meters by mid-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. Any similar situations discovered in Penn Power's service territory are included in the 1.5% estimate and will be addressed in the time frame discussed above.

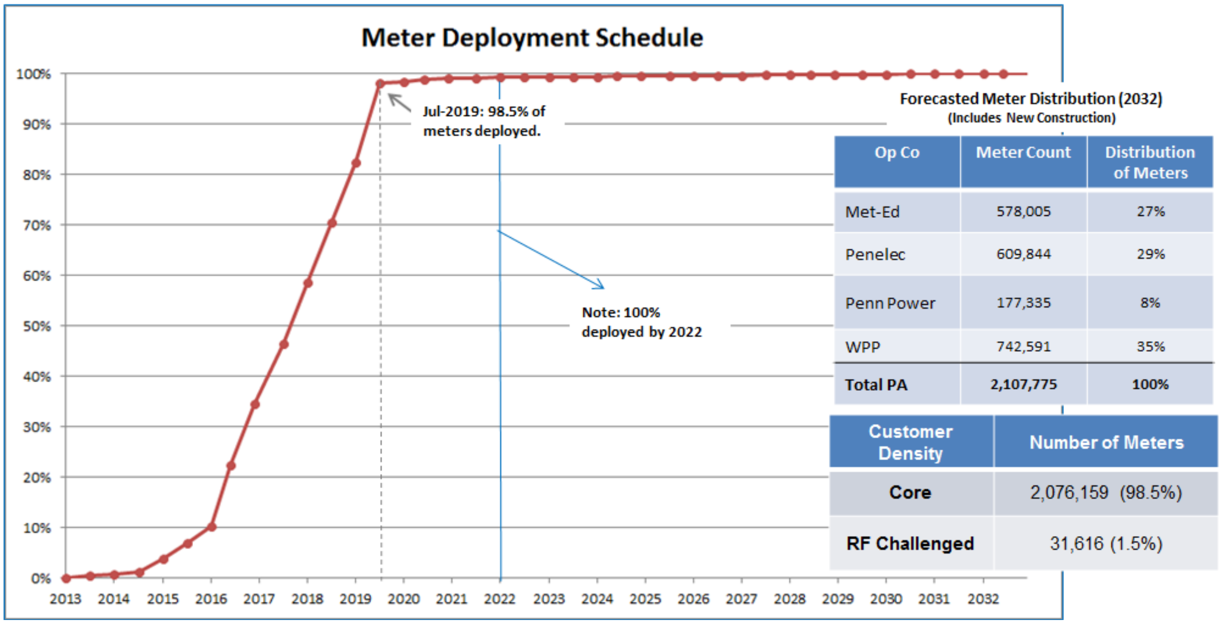
Figure 3.2 illustrates the anticipated implementation schedule while Figure 3.3 illustrates the meter deployment schedule, assuming that the Accelerated Deployment Schedule is adopted:

Figure 3.2 – Smart Meter Deployment Plan Timeframe*



* Estimated schedule for planning purposes

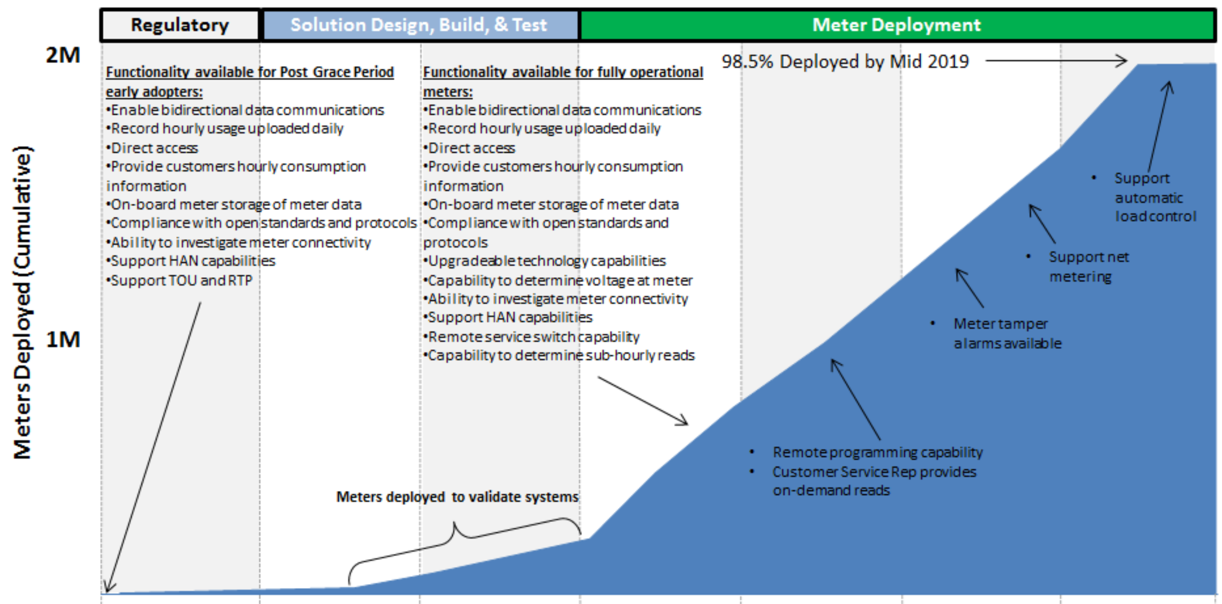
Figure 3.3 – Smart Meter Deployment Timeline – 2014 to 2019



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*	14,000	28,000	42,000	56,000	70,000	84,000	98,000
Staged	-	50,000	170,000	670,000	1,170,000	1,670,000	2,000,000

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 originally involving consultants from IBM and Black & Veatch in 2011 and 2012. This analysis was refined and updated by Accenture, Inc., and Harbourfront Group, along with professionals from the impacted business units of the Companies, the FirstEnergy finance department and its rate department in 2013 and 2014. The data were reviewed and updated in an iterative process throughout 2011, 2012 and again in 2013. The original analytics quantified estimated costs and potential operational savings based on information known as of August, 2012. This analysis was supplemented with additional information, analytics and experiences through 2013 and modified to reflect the Accelerated Deployment Schedule. 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 initially being selected for more in-depth analysis:

- 6-year Two-stage Deployment Scenario ("Original 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 were originally based on the 6-year Recommended Deployment Schedule which anticipated 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, $667.4 million of which are for capital expenditures (“Capex”) and $590 million for Operations and Maintenance (“O&M”) costs. Approximately $816 million will be spent during the six year Deployment Period. The estimated total operational cost savings over the 20 year period that the Companies believed might be realized under the Original Deployment Plan was $406 million in nominal dollars.

Assuming the Accelerated Deployment Schedule is adopted, the estimated cost of implementing the Revised Deployment Plan over 20 years is still $1.258 billion in nominal dollars, $668 million of which will be for CAPEX and $590 million for O&M costs. Approximately $815 million will be spent during the Deployment Period. The estimated total potential operational cost savings over the 20 year period is estimated to be $417 million.

In addition to this analysis, which focuses on the project from the Companies’ perspective, the Companies further analyzed the Revised Deployment Plan from the customer’s perspective. This analysis is discussed in Chapter 4.

Below is a breakdown of the Revised Deployment Plan costs by Company, as generated by the Financial Model:

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

	Total PA	Met-Ed	Penelec	Penn Power	WPP
Capital Costs	**$ 667,390,350**	**$ 181,338,201**	**$ 192,354,386**	**$ 60,847,753**	**$ 232,850,010**
O&M Costs	**$ 590,204,938**	**$ 162,940,051**	**$ 172,612,059**	**$ 46,040,407**	**$ 208,612,421**
Total Costs	**$ 1,257,595,288**	**$ 344,278,252**	**$ 364,966,445**	**$ 106,888,160**	**$ 441,462,431**
Total Savings	**$ 417,023,753**	**$ 102,911,556**	**$ 124,772,459**	**$ 34,358,311**	**$ 154,981,427**

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 Accelerated Deployment Schedule is adopted and that deployment will commence in mid-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 2016 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.[13] 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.

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

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.

The Companies also assessed the project from the residential customer's perspective utilizing a discount rate of .37%, which represents a current typical

[13] 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)

interest rate for a one-year Certificate of Deposit (CD)[14]. This analysis is discussed in Chapter 4.

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 Accelerated 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:

[14] Based upon the average of the initial Local Results Range for one year certificates of deposit for the Reading, Pennsylvania area as of March 10, 2014.

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 competing scenarios taking into account the time value of money from the Companies' perspective. The costs have been adjusted throughout this 20 year period for escalation and growth of the smart meter system based on the six year Accelerated Deployment Schedule. Below is a breakdown of total costs, Capex and O&M:

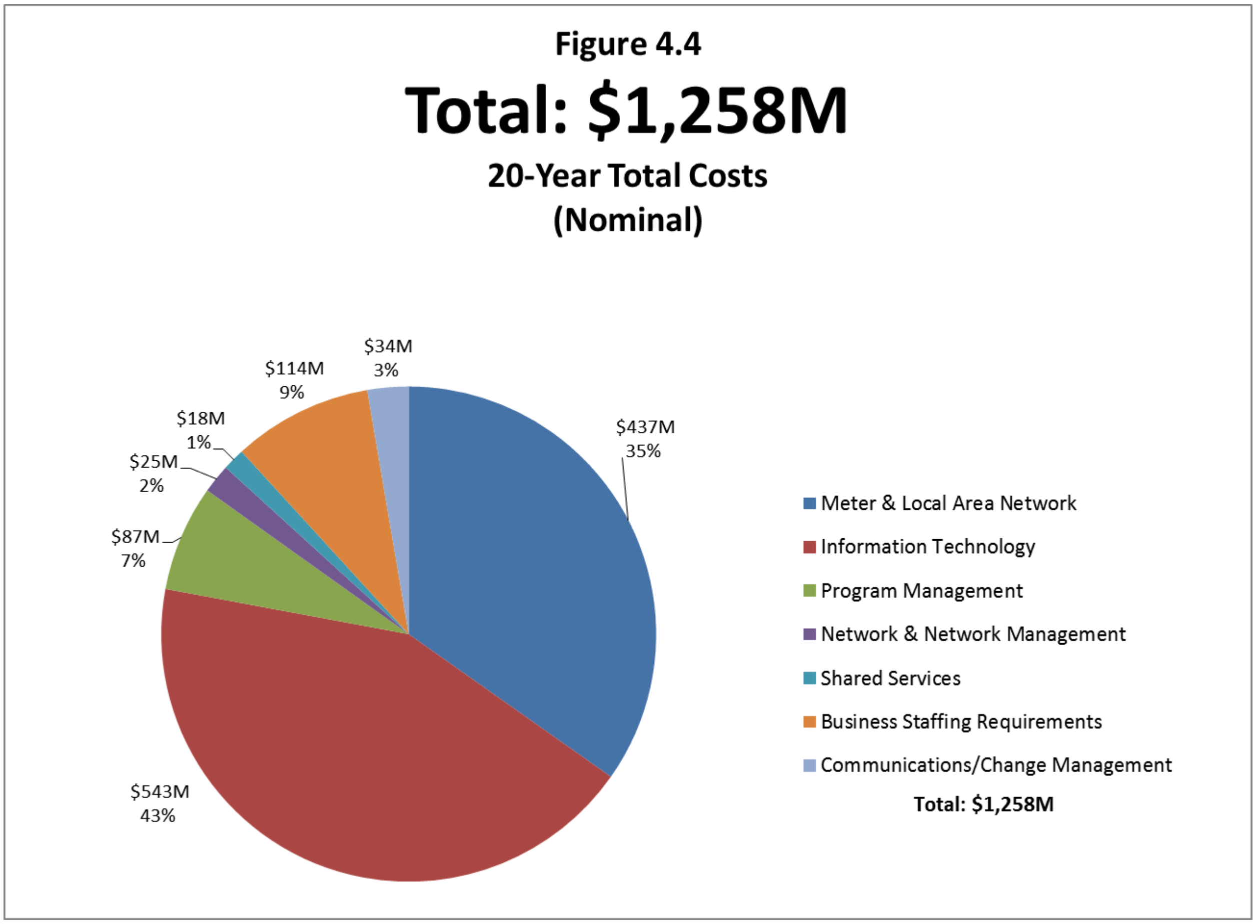


Figure 4.4

Total: $1,258M

20-Year Total Costs (Nominal)

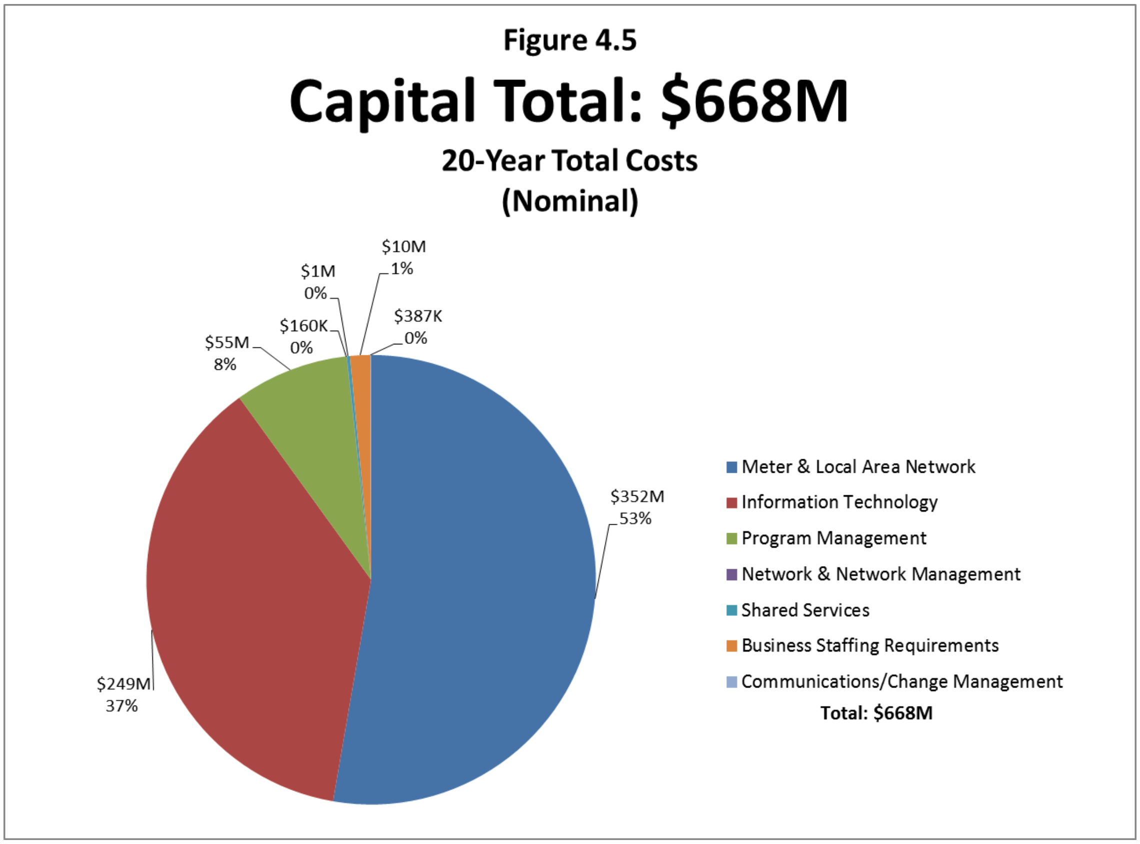


Figure 4.5
Capital Total: $668M
20-Year Total Costs
(Nominal)
$10M
1%
$1M
0%
$387K
0%
$160K
0%
$55M
8%
$352M
53%
$249M
37%
Meter & Local Area Network
Information Technology
Program Management
Network & Network Management
Shared Services
Business Staffing Requirements
Communications/Change Management
Total: $668M

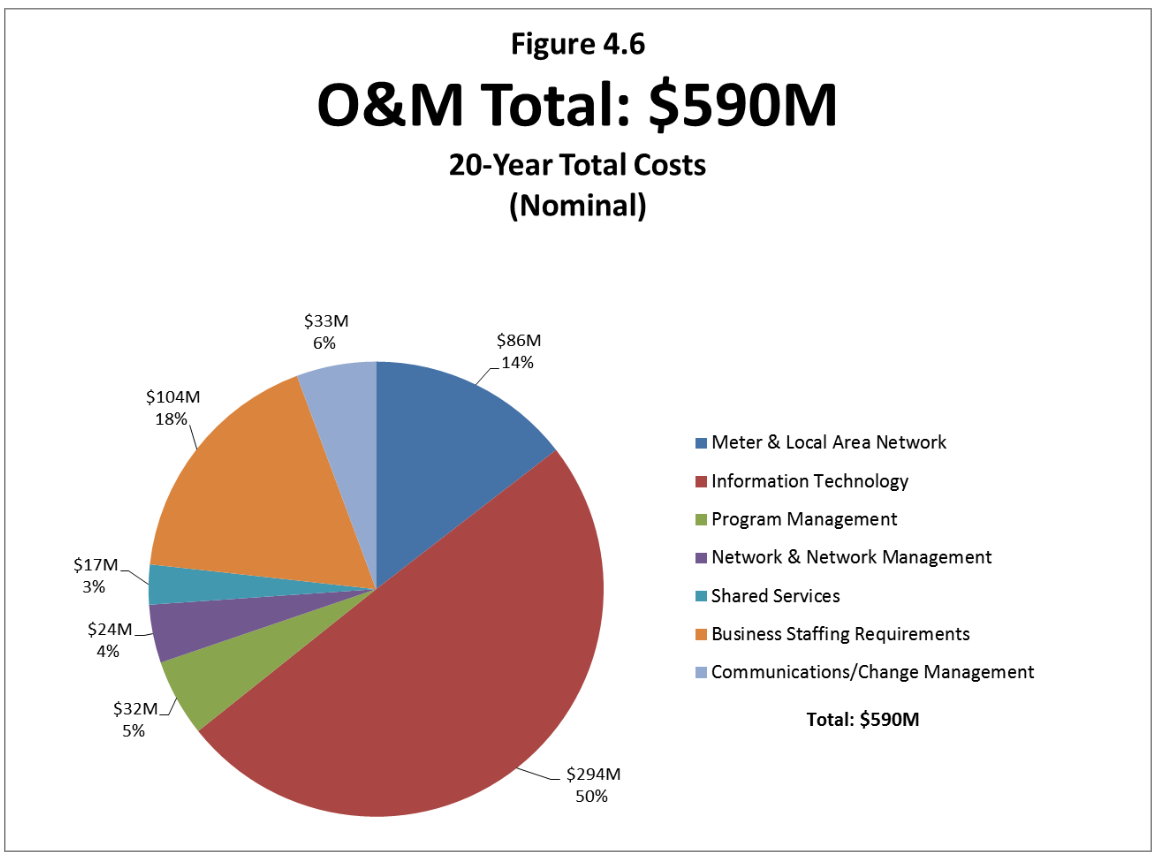


Figure 4.6
O&M Total: $590M
20-Year Total Costs
(Nominal)
$33M
6%
$86M
14%
$104M
18%
$17M
3%
$24M
4%
$32M
5%
$294M
50%
Meter & Local Area Network
Information Technology
Program Management
Network & Network Management
Shared Services
Business Staffing Requirements
Communications/Change Management
Total: $590M

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 Management	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.

Meter and Local Area Network
Total Estimated Cost: $437.5 million (35% of total project costs).

Meters (Capex): $328.1 million

Meters (O&M): $58.4 million

LAN (Capital): $23.7 million

LAN (O&M): $27.3 million

Approximately $351 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.

Network and Network Management
Total Estimated Cost: $24.6 million (2% of total project costs).

Public Backhaul (Capex): $0.2 million

Public Backhaul (O&M): $24.4 million

Approximately $5.0 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.

Information Technology
Total Estimated Costs: $542.7 million (43% of total project costs).

Infrastructure (Capex): $126.7 million

Infrastructure (O&M) costs: $41.3 million

Software Applications (Capex): $38.0 million

Software Applications (O&M): $88.3 million

Resources (Capex): $84.3 million

Resources (O&M): $164.1 million

Approximately $277 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.

Systems Integration
Total Estimated Costs: $87.3 million[15] (7% of total project costs).

Systems Integration (Capex): $54.9 million

Systems Integration (O&M): $32.4 million

Approximately $83.4 million is expected to be spent during the Revised Deployment Plan 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 development in order to realize synergies associated with methodologies and staffing.

Business Staffing and Change Management Requirements
Total Estimated Costs: $147.3 million (12% of total project costs).

Business Staffing (Capex) $9.6 million

Business Staffing (O&M): $103.9 million

Change Management (Capex): $0.4 million

Change Management (O&M): $33.4 million

Approximately $81 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

[15] 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.

those departments needed to achieve the projected operational savings.[16] 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.

Program Management
Total Estimated costs: $18.2 million (1% of total project costs).

PMO (Capex): $1.5 million

PMO (O&M): 16.7 $million

Approximately $15.3 million is expected to be spent during the Revised Deployment Plan 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 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

[16] 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.

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 (Update)

Operational Savings		**20-year Cumulative (Nominal Value)**
Meter Reading		
Meter Reading O&M	$	378,684,741
Meter Reading Handhelds O&M	$	889,996
Meter Reading Handhelds Capital	$	2,654,060
Claims	$	45,406
Meter Services		
Meter Services O&M	$	12,142,190
Meter Services Handhelds O&M	$	37,387
Meter Services Handhelds Capital	$	990,219
Back-Office		
Back-Office/Cust Accounting O&M	$	19,243,257
Contact Center		
Contact Center O&M	$	2,336,497
Total	$	**417,023,753**

4.3.1 Meter Reading

Estimated Potential Realizable Savings: $382.3 million (Approximately 92% of the total projected program operational savings)

Reduction in work force: Approximately $378.7 million (O&M)
Reduction in hand held: Approximately $3.5million ($2.7 million Capex)
Claims: Approximately $0.05 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.
- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

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 $13 million (Approximately 3% of total projected program operational savings).

Reduction in work force: Approximately $12 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[17]); (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

[17] 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.

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 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.

- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

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 $19 million, all O&M (Approximately 5% 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 Accelerated 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%.
- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

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 $2 million, all of which is O&M (Approximately 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 Accelerated 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.
- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

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.

4.4 Analysis of the Revised Deployment Plan From a Customer's Perspective

4.4.1 Background

The Original Deployment Plan incorporated the scenario with the overall lowest, risk adjusted cost from the Companies' perspective, based upon information known at the time the Original Deployment Plan was filed. For purposes of these comparisons, the Companies used their individual WACC as the discount factor for determining the NPV of each of the evaluated scenarios. This approach was appropriate when selecting the best scenario from those competing scenarios, given limited capital resources. However, because the Companies are now proposing to accelerate the original deployment schedule, the proposed modification must also be analyzed from the customer's perspective to determine if the Accelerated Deployment Schedule is financially superior for the customer. The analysis described below indicates that it is.

4.4.2 Analysis

- The model and modeling techniques used to develop the Original Deployment Plan were used to analyze the Revised Deployment Plan.

- All variable model inputs (e.g., the timing of costs and operational cost savings) were updated to reflect the construction of the entire Penn Power system between mid-2014 and the end of 2015, and the commencement of the Full-Scale Deployment Stage in early 2016.

- The net present value analysis used a discount factor reflective of the residential/small business customer, which, for purposes of the analysis was .37%. This rate represents the average of the initial Local Results Range for one year certificates of deposit for the Reading, Pennsylvania area as of March 10, 2014.

4.4.3 Results

Based upon the analysis described above, the total estimated cost of the Revised Deployment Plan on a nominal cost basis does not change. However, with the expansion of the Penn Power build out by approximately 110,000 meters, the acceleration of the completion of the Solution Validation Stage and the commencement of the Full-Scale Deployment Stage by one year, costs will be incurred sooner than originally contemplated. However, potential operational cost savings in Penn Power's service territory will be possible earlier than originally contemplated by virtue of the expanded and accelerated Solution Validation Stage and Full-Scale Deployment Stage operational cost savings will be similarly accelerated due to the earlier commencement of this stage. Therefore, the net projected operational cost savings is estimated to increase by approximately $11 million on a nominal dollar basis, and by $8 million on a NPV basis.

This analysis does not reflect any customer-specific benefits, such as integrated volt-var control, revenue assurance or time varying rates that may accrue to customers sooner than they otherwise would under the Original Deployment Plan.

Figure 4.9 summarizes the estimated costs and estimated operational cost savings under both the Original Deployment Plan and the Revised Deployment Plan:

FIGURE 4.9 - ESTIMATED COSTS AND ESTIMATED OPERATIONAL COST SAVINGS UNDER BOTH THE ORIGINAL DEPLOYMENT PLAN AND THE REVISED DEPLOYMENT PLAN
Output from SMIP Business Case Model

	Capital Cost (A)	O&M Cost (B)	Total Cost (C) = (A) + (B)	Cost Savings (D)	Net Cost (E) = (C) - (D)
Scenario: Original Deployment Plan with Companies' Discount Rates					
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: Revised Deployment with Companies' Discount Rates					
Nominal	$ 667,390,350	$ 590,204,938	$ 1,257,595,288	$ 417,023,753	$ 840,571,535
NPV	$ 438,406,700	$ 311,618,189	$ 750,024,888	$ 142,228,284	$ 607,796,604
Scenario: Original Deployment Plan with Customer Discount Rate					
Nominal	$ 675,545,057	$ 582,050,231	$ 1,257,595,288	$ 405,518,837	$ 852,076,451
NPV	$ 658,920,060	$ 563,621,001	$ 1,222,541,061	$ 386,459,773	$ 836,081,288
Scenario: Revised Deployment Plan with Customer Discount Rate					
Nominal	$ 667,390,350	$ 590,204,938	$ 1,257,595,288	$ 417,023,753	$ 840,571,535
NPV	$ 654,414,560	$ 572,022,644	$ 1,226,437,204	$ 397,924,450	$ 828,512,754

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.[18] 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.[19]

Aside from a compliance tariff update to the text of 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 Revised Deployment Plan. The Companies anticipate this Revised Deployment Plan will be approved by the Commission by June 4, 2014.[20] Once this Plan is approved, the increased costs outlined in Chapter 4, along with the amount being collected in current SMT-C rates effective January 1, 2014 and the proposed SMT-C Rates proposed to be effective from July 1, 2014 through December 31, 2014, 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

[18] Pa.C.S. § 2807(f)(7).

[19] As provided for in the July 29, 2010 Commission Order, at Docket No. M-2009-2123950, the Companies may seek to roll smart meter costs into base rates in the next distribution base rate case and the Commission will determine then whether to allow it. The Companies contended in their Petition for Reconsideration seeking reconsideration of the June 9, 2010 Order that, in the future, it may be desirable to roll existing smart meter costs into base rates while continuing to recover new smart meter costs through their reconcilable SMT-C Rider. If the Companies seek, and the Commission allows, smart meter costs to be rolled into base rates, the smart meter recovery surcharge would be reset to reflect the amount included in base rates so that the Companies are not recovering the same costs both through base rates and the surcharge.

[20] In its March 6, 2014 Order, the Commission indicated that it would rule on this revised deployment plan within 90 days of the date of the Order.

a separate filing and 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.

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 prospective general costs are allocated to each of the Companies' respective customer classes based on the annual average 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 a SMT-C, regardless of whether or not they currently have a smart meter installed at their premises.

The 2013 monthly SMT-C rates for these Companies' customers were 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

The 2014 monthly SMT-C rates for these Companies' customers currently are as follows:

Med-Ed:

- Residential - $1.79 per customer
- Commercial - $1.86 per customer
- Industrial - $1.79 per customer

Penelec:

- Residential - $1.74 per customer
- Commercial - $1.82 per customer
- Industrial - $1.74 per customer

Penn Power:

- Residential - $1.61 per customer
- Commercial - $1.72 per customer
- Industrial - $1.62 per customer

As a result of the revised deployment schedule included in this plan, which increases the number of meters and related equipment and infrastructure to be built in Penn Power's service territory between mid-2014 and the end of 2015, the estimated costs to be incurred are understated. Therefore, the amounts to be recovered are being revised for the last half of 2014 to reflect this increase in spending. The proposed updated 2014 monthly SMT-C rates for these Companies' customers proposed to be effective from July 1, 2014 through December 31, 2014 are as follows:

Med-Ed:

- Residential - $2.31 per customer
- Commercial - $2.25 per customer
- Industrial - $2.22 per customer

Penelec:

- Residential - $2.23 per customer
- Commercial - $2.20 per customer
- Industrial - $2.10 per customer

Penn Power:

- Residential - $2.68 per customer
- Commercial - $2.82 per customer
- Industrial - $2.73 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 2013 monthly SMT-C rates for West Penn's customers were 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

The 2014 monthly SMT-C rates for West Penn's customers currently are as follows:

- Residential - $0.00303 per kWh charged on each customer's monthly bill
- Commercial - $2.89 per customer per month
- Industrial - $2.48 per customer per month

The proposed updated 2014 monthly SMT-C rates for West Penn's customers proposed to be effective from July 1, 2014 through December 31, 2014 are as follows:

- Residential - $0.00355 per kWh charged on each customer's monthly bill
- Commercial - $3.09 per customer per month
- Industrial - $2.43 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
Met-Ed	$0.91 - $4.59	$2.36	$0.96 - $5.27	$2.89	$1.05 - $6.24	$3.52
Penelec	$0.44 - $5.30	$2.56	$0.47 - $6.35	$3.09	$0.78 - $8.15	$4.13
Penn Power	$0.76 - $4.50	$2.26	$0.76 - $4.50	$2.72	$0.95 - $6.10	$3.35
West Penn	$0.70 - $4.92	$2.64	$1.09 - $5.73	$3.27	$2.03 - $6.73	$4.30

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

Consistent with the Commission's March 6, 2014 Order, SMT-C charges will no longer be displayed as a separate line item on the customer's bill. For all metered customers, the Companies will eliminate that presentation and fold the SMT-C charge into the overall distribution rate effective July 1, 2014.

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 elected the latter. Based on the Commission's March 6, 2014 Order in which recovery of these costs was authorized, the remaining $5.1 million is included for recovery 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.

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 plus the Cost of removal net of Salvage 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

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 developed an Internal and External Education and Communications Plan ("Comm Plan"), a Change Management Plan and a Training Plan. At the time of filing the Original Deployment Plan, vendors and technology were just recently selected, and construction of the smart meter infrastructure was not expected to begin until late 2013. As a result, the Companies indicated in the Original Deployment Plan their intent to complete these plans prior to such construction commencing. During the period between the close of the evidentiary hearing in May, 2013 and the end of 2013, the Companies developed a draft Comm Plan. It has been provided to all parties to the case and comments received to date have been incorporated. Consistent with the Commission's March 6, 2014 Order, the Companies will host a stakeholder meeting during the second quarter of 2014 so as to provide interested parties the opportunity to provide input on the Comm Plan prior to it being filed with the Commission shortly thereafter.