THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

Book II – Customer Conservation and Energy Management Programs

Chapter 3

The Dayton Power & Light Company's Advanced Metering Infrastructure Plan

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1 Introduction

1.1 AMI Overview

Advanced Metering Infrastructure (AMI) transforms the meter from a simple measuring and counting device, to one element of an integrated system of hardware, software, and people that can be used to better manage the electric service which customers find essential to their lives. AMI is not simply a tool to capture customer consumption of energy, but a hardware and software architecture capable of capturing real-time consumption, demand, voltage, current and other information. Data can be provided at the customer level and for other enterprise level systems either on a scheduled basis or on demand. A typical AMI network will communicate this data to a central location, sorting and analyzing it for a variety of purposes such as customer billing, outage response, system loading conditions and demand-side management. The AMI network will also send this information to other systems, customers and third parties, as well as send information back through the network and meters to capture additional data, control equipment, and update the configuration of the equipment and software load. This is the principal characteristic of what the industry calls a two-way communications network.

AMI introduces new functionality that will support DP&L's efforts to improve operations and provide greater value to its customers. The availability of near-real and/or real-time consumption data supports time-differentiated rates for customers. DP&L representatives will have access to more complete and current customer data when addressing customer concerns. Moreover, the interval data and accurate load shapes can be made available to customers to help them manage energy costs.

During outages, AMI will make it possible to recognize quickly and accurately service restoration needs, allowing improved crew dispatch, reduction in unneeded trips to customers whose service has already been restored and improve communications with customers and the community. The AMI system provides the ability to detect outages without customer call-ins. This may occur in several ways: some AMI systems are configured to enable the meter to send a “last gasp” signal notifying the utility that the meter has lost power; in other systems the AMI system controller listens continually to the meters and notifies the utility that an outage has occurred when the meter stops transmitting. More accurate information can result in more effective load management activities, and the ability to analyze their impacts. This information can be used to improve load forecasts, hedging, and supply management, as well as distribution system and substation management and planning as the industry gains more experience using the capabilities of AMI.

1.1.1 Enhances Reliability

One of the primary reasons that DP&L is proposing the rollout of AMI is to enhance network reliability and system responsiveness. Only by building an AMI infrastructure can DP&L place sufficient emphasis and dedicate sufficient resources to meeting customers' expectations about the reliability of the electric distribution system.

AMI meters help to enhance reliability by providing:

- Real-time monitoring of the distribution network which allows for earlier outage detection;
- Enhanced ability to locate where an outage has occurred, allowing a utility to dispatch repair crews directly to the location;
- Improved verification of customer service restoration;
- Better control of activity over the distribution systems;
- Additional power quality information, such as voltage, VARs and power factor for residential and C&I customers, which are necessary for better tuning of the distribution network and voltage levels at the substations and regulators along the feeder.

DP&L and the Commission will need to work very closely together on a method to recalibrate some of the reliability metrics currently used once the AMI system is in place. The AMI system will enable DP&L to measure outages more accurately since customer reporting of the outages is no longer necessary. The measured number and length of outages may initially increase due to improved notification and measurement, even though reliability as experienced by customers is expected to improve.

1.1.2 Enables Demand Response

The proposed AMI system will help to minimize the cost of energy and to permit customers to access various demand response programs that improve system load factor and help to defer the construction of new facilities. AMI is a necessary enabling technology for the success of demand response for three primary reasons. First, AMI provides the reliable interval data necessary to measure and verify load reductions achieved by customers, individually and as groups. This allows the market to accurately value customer demand response and allows third parties (e.g., curtailment service providers) to develop demand response programs at a reasonable incremental cost.

Second, AMI provides information necessary for customers, individually and as groups, to determine the load impact of demand responses they might take. This allows customers to make intelligent decisions concerning their levels of participation in various demand response programs available today and in the future.

Third, AMI provides a platform to engage customers in demand response activities. Time-based pricing programs can be tailored carefully and precisely with AMI. Customers can be notified in their homes or businesses when demand response would save them the most money. Prices and financial incentives can target specific outcomes (e.g., peak load reduction for reliability purposes, reduction of peak energy prices, control of local peak loads that may stress the distribution system). Optional load control measures (e.g., home area networks, or chips in the meter that can manage the operation of individual appliances) can help customers optimize their participation in demand response programs without reducing the benefits and value of those appliances to the customer.

The full benefits of demand response cannot be achieved unless the Company is able to implement new programs that encourage load shifting, curtailment and other features. Such programs are part of DP&L's integrated filing and details of those programs are provided in *The Dayton Power and Light Company Energy Efficiency and Demand Response Plan.*

1.1.3 Foundation for Smart Grid

Most utilities consider the implementation of an AMI system to be the fundamental enabling component of the smart grid. Much of the customer benefit of a smart grid infrastructure relies on the capture of detailed data, timely enough to communicate the status of the utility distribution system to process-intelligent controls for the distribution equipment. AMI can potentially capture meter-level activities and data for smart grid applications, for example:

- SCADA voltage telemetry data at feeder breakers in the substations can indicate the quality of the power supply to the distribution network, but voltage information at service transformers and customer delivery points is necessary to discern circuit or transformer level problems for more effective Volt/VAR control.
- Substation breaker and reclosure operations can be used to evaluate the scale of an outage, but meter-level outage and restoration notification events are necessary to optimize outage restoration efforts.
- Emergency load response activities such as load shedding can alleviate potentially catastrophic system concerns, but at a significant cost to customer satisfaction and company image. Demand response information distributed to the individual premise allows utilities to achieve expected load reductions without sacrificing customer satisfaction.

Implementation of a meter data management system (MDMS) and integration of AMI data with distribution management systems (DMS), outage management systems (OMS), and other systems provide the information and intelligent control necessary to facilitate the operation of the smart grid. A smart grid proposal is included as part of DP&L's integrated filing and details of our smart grid plan are provided in *The Dayton Power and Light Company Smart Grid Development Plan.*

1.2 Executive Summary of AMI Plan

1.2.1 Summary AMI Plan

DP&L expects to spend $255.0M in capital and $63.1M in O&M between 2009 and 2015 to implement its AMI plan. Deployment will begin in January 2009 or upon PUCO approval. There are four primary components of an AMI system configuration.

- ***Meters and Modules.*** The proposed AMI system calls for the replacement of all residential and commercial and industrial (C&I) meters with digital electronic meters and communication module combinations that provide full AMI functionality.

- ***Communications Network & Equipment.*** The AMI communications solution consists of communications hardware and software and associated system and data management software that create a two-way communications network between AMI meters and utility business systems which allow collection and distribution of information to customers and the utility.

- ***Home Energy Displays.*** DP&L's plan includes support for a customer Home Area Network (HAN) and includes energy display devices that are easily accessible and easy to use that show customers their current energy usage, trends, and current energy prices. DP&L will make energy displays available to customers who do not have Internet access or who choose to gain real-time energy usage information through this device rather than through the Internet.

- ***IT Systems.*** Effective implementation of advanced AMI technology requires installation of a MDMS and the modification and/or purchase of supporting IT systems which will make it possible for DP&L to manage the enhanced operational environment and take advantage of the new data that is captured by the AMI system.

1.3 Methodology for Preparing Business Case

Over the past year DP&L has been learning and evaluating the various technologies to implement AMI. Technology vendors have given presentations to cross-functional teams within the Company. DP&L employees attended several conferences and visited utilities that have implemented different components of AMI and smart grid technologies to gain a broader knowledge of the successes and pitfalls others have experienced in the implementations of these technologies.

DP&L also engaged a consulting firm, Bridge Strategy Group, to assist the Company in research and analysis to develop a feasible and cost-effective AMI strategy for its electric services. The principal aspects of the work were: (1) the identification of the goals for AMI and the potential costs and benefits of an effective and efficient advanced metering system, (2) the identification of appropriate technology, and (3) the analysis that reflects these findings.

The assessment of the cost-effectiveness of advanced electric infrastructure has been a complex undertaking. Cost estimates depend on the identification of the appropriate meters, the communication infrastructure, the meter data management systems, and load management system to be employed. Choosing among the available systems requires an understanding of how each possible system would be arrayed across the specific topography and meter locations in the Company's service territory in order to provide the desired degree of timeliness and consistency in the communication of meter data.

The information for estimating meter, communication equipment, and installation costs was developed from proposals provided by vendors based on a formal request for proposal (RFP) process. DP&L worked with a third party IT consulting firm to estimate the IT, IT-related infrastructure and IT integration requirements necessary to support the future AMI capabilities. The project team relied upon the IT firm's experience in utility specific transformation programs, as well as DP&L's knowledge of the existing infrastructure and future operating vision.

Integrated analysis was carried out by projecting the system costs on an overall basis for DP&L and forecasting other costs applicable specifically to each of the distinct areas within DP&L's service territory

Consistent with manufacturers' representations and the regulatory filings made by other utilities regarding expected equipment life, the cost analysis assumed a meter equipment life of 15 years, a communications infrastructure life of 10 years, and an information technology hardware life of 7 years.[1] The plan is for a six year system-wide deployment schedule commencing in January 2009 or upon Commission approval and with a 3.25% inflation rate applied to project costs.

[1] Southern California Edison Testimony Supporting Application for Approval of Advanced metering infrastructure Pre-Deployment Activities and Cost Recovery Mechanism. Volume 3-AMI Preliminary Cost Benefit Analysis (December 21, 2006)

2 DP&L Characteristics

2.1 Existing Metering, Communications, and IT Systems

2.1.1 Meters

Currently DP&L has a wide variety of meter types and technology. The metering technology runs from electro-mechanical to electronic, interval and to usage only. The company made the decision in 2006 to purchase only electronic meters in the future. There are 521,310 meters in the field, 501,826 are self-contained single-phase units and 19,484 are poly-phase and transformer-rated units. There are approximately 112,000 residential self-contained single-phase meters equipped with old one-way mobile reading technology. This figure represents approximately 22% of the residential meters installed in the DP&L service territory. There are 600 meters capable of interval data storage of the 19,484 poly-phase and transformer rated meters.

2.1.2 Communications Network and Equipment

DP&L currently owns and operates the following communication systems:

- An analog 800 MHz system used for voice dispatch of DP&L's mobile workforce.
- A 900 MHz multiple-address radio system for collecting substation SCADA data.
- A microwave back-haul system consists of thirty-two sites of which twenty-two are configured in an OC3 SONET ring. The remaining sites are hot-standby spurs ranging from 16 T1 to DS3 capacity.
- An OC12 SONET fiber system in the metro Dayton area connecting 16 substations in a collapsed-ring configuration. The Microwave and fiber systems are used to transport data for substation RTUs, substation protection, WANS, voice telephones, and the 800 MHz two-way radio system.

2.1.3 IT Systems

DP&L has several key legacy and home-grown IT systems in place to maintain daily operations. Our current customer information system, outage management system and service order processing system were designed and developed independently of each other and, over time, have been integrated with each other as needed. Although they are currently meeting our operational requirements, the advent of AMI will require a more flexible set of IT systems that will be able to meet the needs of our new AMI customer base and to enable customer participation in the evolving energy efficiency and demand response programs. It would be difficult and costly to further customize our existing legacy and home-grown systems in order to take advantage of the new opportunities and benefits afforded by AMI, respond quickly to market and regulatory changes, and create and manage a suite of energy efficiency programs tailor-made for our customers.

DP&L currently has a small Meter Data Management (MDMS) system. The Itron MV-90 system is used as the current data repository and data verification and editing tool for the interval meter data collected on 600 large industrial customers. The system is small, can grow only to approximately 2,000 interval data meters, and will not support the expansion into a fully-implemented AMI system.

2.2 Customer Characteristics

Key customer demographics such as customer type and geography drive feasibility, costs, and strategy for AMI.

2.2.1 Customer Type

Table 2.2.1. Number of Customers in Customer Classes

	Residential	Commercial	Industrial	Public Authority	Highway Lighting	Total
Customers	456,688	49,534	1,816	4,539	1,827	514,404
% of Total Number of Customers	88.8%	9.6%	0.4%	0.9%	0.4%	100.0%

2.2.2 Geography

The Dayton Power and Light service territory is 6000 square miles across southwest Ohio. Of this figure, 600 square miles are densely populated in the Greater Dayton, Ohio area, while 5,400 square miles are rural areas with small towns throughout the area. DP&L serves 24 counties across its territory. Approximately 60% of customers are in the Greater Dayton area, with the remaining 40% of customers in the rural areas.

3 Proposed AMI Systems Configuration

3.1 Meters and Modules

The proposed AMI system calls for the replacement of substantially all residential and commercial meters with digital electronic meters and communication module combinations that provide full AMI functionality defined as:

- Capable of measuring and recording usage data in time-differentiated registers, including 5 minute, 15 minute, hourly or such interval as is specified by DP&L.
- Allowing electric consumers, suppliers and service providers to participate in all types of price-based demand response programs noted in the project background.
- Providing the utility with key data and functionality that address power quality and other electric service issues. This information can be used to optimize the distribution network and to trouble shoot failed or failing equipment.
- Providing a Home Area Network gateway that can communicate with a variety of other key components necessary for the realization of energy efficiency and demand reduction during peak periods. These devices include programmable thermostats, home energy displays (HEDs), load control relays, and in the future smart appliances and switches and residential energy management systems.

- Supporting Bi-Directional and net metering where the meter can record energy flow in either direction and calculate net usage. This capability will be important in the future as distributed generation becomes a reality.

- All single-phase class 200 meters or less will have remote connect/disconnect capability along with load limiting capabilities

This functionality can reside in the meter alone, or will be provided through a combination of meter and network communications functionality.

The Company's proposed meter rollout schedule is provided in Table 3.1.

Table 3.1 Meter Deployment Schedule

AMI Meter Deployment	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Residential Meters	10,037	50,183	75,274	115,420	125,457	125,457	1,716	503,542
C&I Meters	389	1,897	2,846	4,364	4,744	4,744	-	18,984
Power Quality Meters	10	50	75	115	125	125	-	500
Total Meters	10,436	52,130	78,195	119,899	130,325	130,325	1,716	523,026

3.2 Communications Network and Equipment

3.2.1 Overview of Communication Requirements

The AMI communications solution consists of communications hardware and software and associated system and data management software that create a two-way communications network between AMI meters and utility business systems which allow collection and distribution of information to customers and the utility. The key attributes of the AMI Communications solution are:

- Provide coverage for 100% of meters in DP&L service territory.

- Capable of capturing 15 minute interval reads and reporting all of DP&L residential meters every 60 minutes.

- Capable of capturing 5 minute interval reads and reporting DP&L C&I customer meters every 30 minutes.

- Provides very low latency communications with the meter to do an on demand read/status inquiry of a customer meter while the customer might be on the phone with a DP&L customer care representative, within 10 seconds.

- Provides bandwidth to support the applications of tomorrow. These applications could include applications that create asynchronous message traffic to/from the HEDs and programmable thermostats. For example, emergency messages from the local municipality for weather, fire, or other threats or DP&L's retrieval of thermostat information regarding how often the air conditioner/furnace is in use. This information can be trended to detect when the customer may need a HVAC tune up or when filters should be changed. Applications could also include the need to send billing and usage information back to meter or energy display device when the user requests the information or on a regular or on-demand basis.

- Able to use the user interface of the C&I meter to access the meter remotely when there is a reported issue at a C&I customer, rather than having to put a power quality monitor at the customer's site.

- Able to support capturing the out-of-service and back-in-service transitions for large scale outages.

- The result will be a combination of multiple AMI communication technologies to reach all customers. Multiple technologies will be necessary to serve DP&L's diverse population density and terrain and to serve as an alternate way to reach meters when the primary approach of the AMI communication system does not work for a particular group of meters.

3.2.2 AMI Communications

AMI communications are divided into three key areas: AMI Infrastructure, 2-Way Voice/Data network, and Microwave IP backbone. These three networks make up the critical communications that provide the end-to-end communications to connect the AMI Meters for C&I and residential, new substation control, and the distribution automation devices on the feeders to the DP&L IT systems that control, monitor, and collect data from these more than 500,000 monitoring devices in the field.

3.2.2.1 AMI Infrastructure

The AMI Infrastructure is the communications hardware and software and associated system and data management software that creates a two-way communications network between AMI meters and the new Microwave IP backbone that connects to the utility business systems which allow collection and distribution of the AMI information to customers and the utility. This infrastructure must provide the connectivity to all the meters in DP&L's service territory which has a very wide variety of coverage requirements, from urban to rural and from outdoor meters to those in a basement or metering closet. DP&L evaluated many AMI communication solutions and chose to use a single AMI solution across its diverse service territory to complement the 2-Way Voice/Data network that is providing AMI connectivity to DP&L's top 500 C&I customers.

The AMI infrastructure is located in DP&L substations and connected to the IP backbone through the new Microwave IP network (section 3.2.2.3) or through existing fiber assets. All of the IP backhaul associated with the AMI Infrastructure and 2-Way Voice & Data solution (section 3.2.2.2) will be owned and operated by DP&L to ensure the highest system reliability, security standards, and lowest overall cost of ownership as compared to purchasing broadband solutions from multiple IP service providers in the DP&L service territory.

3.2.2.2 Licensed 800 MHz IP Fixed Data Solution (2-Way Voice/Data Network)

This wide-area data network will be necessary to provide connectivity to over 500 of DP&L's largest Commercial and Industrial customers for AMI power quality services, to provide connectivity to distribution automation devices, and to ensure standard AMI service to 100% of DP&L's meters anywhere in its service territory.[2]

[2] Distribution Automation (DA) devices as described in *The Dayton Power and Light Company Smart Grid Development Plan.*

This new network was selected to enable the communications to DP&L's top 500 C&I customers while meeting DP&L's requirements for reliability, flexibility, throughput, and very low latency (less than one second response time). The licensed 800 MHz IP fixed data network supports IP communications at 96kbps over the air data rate, enabling DP&L not only to collect 5 minute interval AMI information but also to remotely open the user interface of the C&I meter to analyze key power quality measurements associated with the energy being delivered to DP&L's largest customers. This ability to view real-time power quality information from DP&L's largest customers in an on-demand fashion will enable DP&L to remotely troubleshoot and to monitor any power-related issues for this customer segment. Today's standard AMI solutions have high latency characteristics and cannot provide the real-time power quality feeds from the C&I power quality meters. And, while public carrier based IP solutions can provide real-time power feeds from C&I smart meters, these IP solutions do not have ubiquitous coverage throughout DP&L's service territory. In addition, public carrier-based solutions do not have the operational reliability required by DP&L during critical emergency situations.

The licensed 800 MHz IP fixed data network is also critical to support DP&L's smart grid strategy by providing communications to distribution automation devices that make up the new control and monitoring points in the electrical distribution network.[3] This network provides continuous coverage in the urban and rural areas as well as the reliability and security necessary to support these new critical components in DP&L's electric distribution network. The Company believes that for both safety reasons and for optimal control, the control of these active devices must be through a licensed, secure, and extremely low latency communication link that also has coverage throughout the service territory. It is important that the communication link be IP-based with significant capacity to be able to deliver remote, real-time SCADA information but also be able to remotely configure and troubleshoot control devices.

The third reason to deploy the licensed 800 MHz IP fixed data network is to deliver AMI capabilities to those otherwise excluded from the standard AMI solution due to lack of AI radio

[3] Detail of substation and distribution automation devices provided in *The Dayton Power and Light Company Smart Grid Development Plan.*

coverage for those meters. The number of meters that otherwise would be expected not to have AMI coverage is between 0.5% and 1.0%.

DP&L evaluated several potential solutions to meet the needs of power quality meters, distribution automation, and 100% AMI meter coverage. DP&L concluded that a licensed 800 MHz two-way IP fixed data solution would meet the Company's needs. Due to spectrum constraints in this band, the most cost effective method is to replace the existing analog 800 MHz dispatch solution with a multi-functional 2-way voice/data IP solution that can reuse the 800 MHz frequencies that DP&L already owns. Since the new system is spectrally more efficient it will meet the requirements of the licensed 800 MHz IP fixed data network as well as support the voice dispatch requirements that were previously supported by the existing analog 800 MHz system. Effectively, this new licensed 800 MHz IP fixed data solution will replace DP&L's existing analog 800 MHz system used for voice dispatch of the mobile workforce.

DP&L will see operational improvements associated with dispatch efficiencies from this new solution, as outlined in section 4.2 of this chapter.

3.2.2.3 Microwave IP Backbone

Due to the additional bandwidth needed to support the new data systems for AMI, distribution automation, substation automation, the licensed 800 MHz IP fixed data network, as well as the fact that the current SONET Microwave network is near 80% of its capacity, a new IP-based Microwave system will be installed. This network provides the connectivity to the licensed 800 MHz IP fixed data network base stations and AMI access points, and distribution substation communication gateways, located in substations dispersed throughout DP&L's 6,000 square mile service territory. The upgraded Microwave IP network will allow for IP traffic flexibility and bandwidth for all devices in the field along with bandwidth shaping capability and redundancy in case of any one individual link failure. This network will provide the necessary capacity, reliability, and security to support the extensive communications required for all of DP&L's needs related to AMI, energy efficiency, demand response, and smart grid.

The Company evaluated several options to provide the necessary bandwidth to support the integrated Customer Conservation and Energy Management ("CCEM") initiative. It was determined that the most cost-effective solution is to replace the existing SONET Microwave system. The existing SONET Microwave system does not have the additional capacity to support the communication from the substations, distribution automation components, or the AMI meters. DP&L explored an overlay design that would add an additional Microwave channel on the current ring architecture to carry the IP traffic. DP&L concluded that the most cost effective solution is to replace the existing SONET Microwave network with a new IP-based Microwave system. The primary benefits of this replacement strategy include:

- Reduction of maintenance from two microwave networks to a single network
- Reduction of power, battery back-up, and floor space requirements at the microwave sites
- More expedient switchover to back-up control center during a disaster

The capital and expense benefits of replacing the existing system that led DP&L to decide to replace the current system are outlined in section 4.2 of this chapter.

Also in support of the smart grid strategy, specifically the upgraded SCADA communications to the new communication gateways in the distribution substations, DP&L will deploy broadband IP radios to interconnect the Microwave sites with the remaining distribution substations not served by Microwave fiber. These broadband IP radios will not only support today's real-time SCADA monitoring traffic but also will support the remote configuration management and performance management reporting and troubleshooting capabilities of the new substation automation devices.

3.3 Home Energy Displays

DP&L's plan includes support for a customer Home Area Network (HAN) and includes home energy displays that will provide information on current energy consumption and prices.

The display will also receive and display signals regarding peak and/or critical peak pricing periods. Many customers will choose to get real-time information on energy usage, pricing, and trends from the new website portal that will be available to them via the Internet; however customers can request a home energy display (HED) by DP&L.

3.4 IT Systems

3.4.1 Summary Requirements

Effective implementation of advanced AMI technology requires installation of a Meter Data Management (MDMS) system and the modification and/or purchase of supporting IT systems which will make it possible for DP&L to manage the enhanced operational environment and take advantage of the new data that is captured by the AMI system. The technical integration of these systems will be implemented to ensure a smooth transition to the new operating model.

Exhibits 3.4.1.a and 3.4.1.b list the functional gaps that DP&L has identified in its current IT systems that need to be addressed.

Exhibit 3.4.1.a IT Systems Gap Analysis

Functional Area	Capability Gaps
Meter Data Management	**Currently DP&L's legacy MV90 and Field Collection Systems lack the ability to:** ▪ Capture and store hourly meter interval data required for incentive based rates or demand reduction initiatives ▪ Capture and store meter related events for immediate action or compilation of data for studies over time ▪ Calculate the billing determinants that will allow more flexible rate design and energy consumption billing ▪ Provide historical usage data to its residential class of customer that can enable demand reductions and energy conservation
Load Management	**Currently DP&L has no load management system in place and lacks the ability to:** ▪ Control load control devices for Demand Response benefits ▪ Aggregate multiple load control devices across device type or customer class to initiate effective demand response events ▪ Develop control strategies to meet the needs of particular demand response events ▪ Verify the activation of load control devices should a demand response event be called
Customer Information Management	**DP&L's legacy customer information system (CIS) will not readily support:** ▪ New customer rate and billing options (e.g. Critical Peak Pricing, Real-time Pricing) ▪ Online bill payment and customer self-service options ▪ Tracking of customer participation in proposed energy efficiency and demand response programs ▪ Easy integration with other systems critical to AMI ▪ Flexible reporting capabilities resulting in limited ability to report on key energy efficiency and demand response program success measures and targets ▪ Enhanced service order processing ▪ Flexible collection and payment options to maximize the benefits of AMI and energy efficiency and demand response programs ▪ Quick adaptation to new billing, accounting, and financial requirements necessary to manage non-commodity services ▪ Quick adoption of new cash processing methods and flexible payment posting options needed for non-commodity services ▪ Quick redesign of bill formats to show additional data related to AMI ▪ Quick design of customer correspondence and the ability to limit distribution to specific targeted customers ▪ Flexible processing of financial adjustments such as rebates or discounts available as part of new energy efficiency and demand response programs
eServices	**DP&L has a limited web presence and does not have the current capability to:** ▪ Support web-enabled enrollment in new energy efficiency and demand response programs ▪ Support web-enabled sign-up for Customer Energy Audits ▪ Accommodate online Customer Energy Use Surveys ▪ Allow customer to view their bill/bill insert(s) online to see current energy efficiency and demand response program credits and/or debits ▪ Allow customer to view past energy use ▪ Allow customer to view historical interval usage and the associated pricing ▪ Support outbound web-enabled notification of energy events (e.g. direct load control, capacity load reduction, scheduled load reduction, critical peak pricing, demand bidding, capacity bidding) ▪ Store and report on critical metrics to gauge program success.

Exhibit 3.4.1.b IT Systems Gap Analysis (Continued)

Functional Area	Capability Gaps
Outage Management	**DP&L's current outage management system lacks the following capabilities to maximize the benefits of the transition to AMI:** ▪ Capture and store meter events and alarms created by the AMI system ▪ Display the location of meter related events and alarms on a geographical electronic map ▪ Associate meter events with specific isolation and sectionalizing equipment within the DP&L distribution infrastructure ▪ Provide automated aggregation of both IVR and AMI related inputs to predict outage failure locations and isolation/sectionalizing equipment ▪ Provide automated restoration confirmation capability upon re-energizing sectionalizing equipment for restoration purposes
Mobile Workforce Management	**DP&L's current service order system lacks the following capabilities to maximize the benefits of the transition to AMI:** ▪ Generate and dispatch outage orders created by the Outage Management System ▪ Display the location service orders on a geographical electronic map ▪ Provide least cost travel routing for service orders ▪ Display real-time vehicle/staff location on a geographical electronic map ▪ Provide automated resource allocation based upon vehicle staffing and equipment availability in a geographic area ▪ Associate meter remove service orders with AMI systems and MDMS to prevent false outage signals ▪ Provide in-field order initialization and automated order completion within CIS ▪ Provide real-time service order status with communication to DP&L Call Center staff ▪ Provide service order assignment and scheduling based upon resource capability and geographic location
Distribution Management	**Currently DP&L has no distribution management system (DMS). A DMS would allow DP&L more efficiency to:** ▪ Perform System Analysis ▪ Plan Daily Operations ▪ Manage Planned Events ▪ Analyze Distribution System Optimization
Service-Oriented Architecture	**Current DP&L application integration organization, processes, tools and techniques are unable to:** ▪ Automate AMI and smart grid processes ▪ Capture real-time process data across systems and organizations ▪ View end-to-end processes regardless of underlying supporting legacy systems, organizations or owners ▪ Quickly and efficiently modify end-to-end processes to meet the needs of customers and regulators
IT Infrastructure	**Current DP&L servers and storage hardware are unable to support new applications.** **Current DP&L Disaster Recovery plans, processes, tools and techniques are unable to adequately support AMI and Smart Grid in the event of a business disruption or disaster at DP&L sites.** **Current DP&L IT infrastructure organization, processes and supporting systems software is unable to:** ▪ Support the increased Service Desk service levels required by users ▪ Schedule batch jobs efficiently and effectively ▪ Manage the many configurations of application versions in production, QA, test and development environments ▪ Monitor and manage the data network ▪ Efficiently plan and manage server and storage capacity ▪ Manage the increased security, identity and access requirements of AMI

3.4.2 Meter Data Management System

The primary purpose of a Meter Data Management System (MDMS) is to provide storage for and access to the massive amounts of data that will be obtained from an AMI system and coordinate/manipulate that data into actionable formats for the various other systems deployed as a result of AMI. Types of data that will be captured for every AMI meter within the DP&L system include:

- Meter reading interval data
  - Hourly intervals
  - 15 Minute intervals
  - 5 Minute intervals
- Meter events
  - Tamper alarms
  - High/Low Voltage alarms
  - Minimum/Maximum Voltage readings
  - Flicker Counts (No voltage events less than x seconds)
  - Outage events (No voltage events exceeding x seconds)
  - Restoration events (Voltage return after and outage)

While MDMS is primarily a repository of data, it does provide functionality enhancing the capabilities of other systems through more accurate and granular data flow. Typical functionality includes validation, estimation and editing (VEE) of meter reading data and the calculation of billing determinants to be provided to the customer information system (CIS).

AMI coupled with MDMS provides the ability for CIS to generate time differentiated incentive based rates promoting the true cost of energy to its consumers. Additionally, this data, coupled with a more robust eService platform, can provide consumers with a view of their actual usage over time, fostering conservation, lowering the consumer's bills, and providing resulting system demand reductions.

Additionally, the MDMS provides data storage for reviewing consumption patterns for various classes of customers, improving analysis and accuracy for rate design, load forecasting for buy-versus-build decisions for both energy and capital improvements to the distribution infrastructure. MDMS will also act as a gateway to consolidate and communicate data flow from DP&L's various infrastructure systems (CIS, OMS, MWMS etc.) to the multiple AMI systems deployed within DP&L's service territory.

3.4.3 Load Management System

One of the important capabilities for DP&L's AMI deployment is to provide two-way communications to various in-home load control devices for voluntary demand reductions during critical peak periods on the DP&L distribution system. For DP&L to obtain this important benefit it must implement a Load Management System (LMS).

The primary purpose of a LMS is to provide a database of the load control devices that have been enabled through the DP&L CIS and have been installed throughout DP&L's customer base to allow for the aggregation and activation of those devices during a demand response event. In addition to maintaining the types, account numbers, locations, and distribution system information, the system will provide the following functionality:

- Load Control—The ability to control multiple load control devices into one demand response event.
- Demand Response Verification—The ability to verify that when a load control device is activated that it did in fact activate.
- Control Strategies—Maintenance of a table of various load control devices to provide predetermined demand response levels.
- Set Point Configuration—The ability to configure programmable thermostats for various temperature-set forward levels.
- Profile Support—Analysis routines that provide time-based profiles of the estimated achievable load response during a demand response event.
- What If Analysis—Provides the capability to assign and re-assign various load aggregation groups to estimate the most effective load control strategies under varying circumstances.

LMS coupled with AMI provides the ability for DP&L to control direct load control devices (DLC) and programmable thermostats based upon the scenarios and models that are created and stored in the LMS. Another critical function of LMS is to maintain a record of demand response events called for each device so that its use does not exceed the contractual obligations setup in either the rates or Demand Response Programs to which the consumer has consented.

A Load Management System coupled with effective demand response programs will allow DP&L to lower peak demand requirements during high usage or emergency curtailment periods across its distribution system. Additionally Load Management will improve the reliability of DP&L's distribution system for its consumers by allowing voluntary load shedding during system duress periods created by damage to its distribution infrastructure through accidental or storm-related equipment failures.

3.4.4 Customer Information System

DP&L's Customer Information System (CIS) is a set of process-related applications used to manage customer information for metering, billing, orders, collections, customer segmentation, rate activity, and payment processing. DP&L views the CIS as central to performing daily operations and key to customer satisfaction, making it a critical system.

In order to utilize fully the capabilities of AMI as well as its energy efficiency and demand response programs, DP&L will need to make enterprise-wide changes with regard to how we process vast amounts of data, manage new energy efficiency and demand response programs, implement new rates and modify the vast majority of our existing meter-to-cash business processes. Instead of having a CIS that enables our business to react quickly and effectively to the changing energy environment, the costs associated with modifying our legacy CIS have severely restricted progress with regard to embracing AMI, implementing evolving market rules, and accommodating the changing demands and expectations of our customers.

The combination of AMI and new energy efficiency and demand response programs will enable DP&L's CIS to perform enhanced billing calculations and support faster throughput capabilities as more data is processed to accommodate new billing, rates and flexible options from smart metering implementations. In addition, DP&L's CIS system must support benchmarking for customer care statistics, analysis of demographics, and customer segmentation to drive customer prospecting and retention practices, as well as to provide data to support business development process improvements. Therefore DP&L proposes the purchase and implementation of a new CIS whose more flexible and configurable architecture will allow for DP&L quickly and more affordably to make the changes necessary to deliver the value created by AMI, now and in the future. The new and improved features will become increasingly important to our customers as DP&L strives to offer new demand side management options to its customers and to meet future energy efficiency and load control targets. This new system will be flexible, scalable and configurable, which will allow DP&L to focus on designing creative solutions to meet the needs of future unpredictable business conditions, while at the same time knowing it has the tools in place to make technical changes quickly.

3.4.5 eServices

As DP&L implements AMI and energy efficiency and demand response programs, we need to define a new approach to how it interacts with its customers and determine what the desired "customer experience" with DP&L will be. As our customers become more empowered to control their own energy use, DP&L must make the tools available to them to make this experience a positive one. DP&L realizes the need to integrate customer awareness and satisfaction into our energy efficiency and demand response strategy to maximize the value of our program investments. Details of proposed programs are provided in *The Dayton Power and Light Company Energy Efficiency and Demand Response Plan.* With this objective in mind, DP&L plans to develop a comprehensive set of eServices as a primary method to educate our customers about the programs we offer, the benefits of those programs and how to participate. Customers will be able to enroll in energy efficiency and demand response programs, participate in customer energy audits, and respond to customer energy use surveys via an enhanced company website. Customers will also be able to view their past energy use, billing information and historical interval usage and associated pricing data as part of the eServices DP&L plans to develop. Another critical component of DP&L's eServices offering is the capability for outbound web-enabled notification of energy events related to direct load control, scheduled load reduction and critical peak pricing programs, which will enable eligible customers to participate in these load reduction events.

Participating in an energy efficiency and/or demand response program may be the most significant interaction that many customers will have with DP&L. Even if they choose not to participate, knowing that DP&L offers these programs may have a significant influence on their behavior because they are more aware of their energy usage. By establishing a strong web presence, and offering a variety of beneficial e-Service options, DP&L will be better able to increase customer satisfaction.

3.4.6 Outage Management System

For DP&L to maximize the benefits proposed by implementing AMI we will need to replace our legacy outage management system (OMS) with a more flexible and robust OMS. Currently our OMS accepts IVR information and actual customer contact information for the generation of outage events. A new OMS is needed to incorporate the additional data, such as outage alarms, restoration alarms, and low-and high-voltage alarms generated in real-time from an AMI System.

In addition to the compilation of massive amounts of data, OMS provides tools to restore power to DP&L customers efficiently. The new OMS will receive and process various inputs for outage analysis, predict locations of outages, manage crews, allow dynamic circuit model changes and maintain historical data. DP&L's current outage system was not designed or built for these types of advanced features. The following capabilities will allow DP&L to process information through all stages of an outage:

- Capture and store meter events and alarms created by the AMI system;
- Display the location of meter-related events and alarms on a geographical electronic map;
- Associate meter events with specific isolation and sectionalizing equipment within the DP&L distribution infrastructure ;
- Provide automated grouping of both IVR and AMI related inputs to predict outage failure locations and isolation/sectionalizing equipment;
- Provide automated restoration confirmation capability upon re-energizing sectionalizing equipment for restoration purposes;
- Provide outage-prioritization recommendations based upon loads, customer class, life support, or reliability indices;
- Provide automated reliability indices reporting based upon actual outage and restoration times and customers affected for business process improvements and regulatory review.

DP&L's mapping and AMI systems will provide the additional customer status and location information necessary to advance OMS capability beyond the system inputs of our current

Trouble Call Management System (TCMS) and SCADA. While these traditional methods of obtaining outage information are certainly valuable, they do not provide sufficient detail or the geographic visibility necessary to deploy work crews in the most efficient manner. The addition of real-time outage information originating from AMI, coupled with the customer's location provides the missing ingredient for efficient outage response, particularly during the occurrence of major outage events.

A sophisticated OMS is needed to manage the large amount of information generated from so many diverse sources. OMS will provide several operational layers that perform essential tasks related to outage detection, analysis, diagnosis and restoration. OMS is capable of identifying the various types of inputs, evaluating them by reconciling the divergent system, subsystem and endpoint sources, diagnosing the most likely causes(s) and current status, and then transferring this knowledge in a manner that efficiently utilizes DP&L's available restoration resources. OMS will provide for the efficient transfer of information concerning changing network status.

3.4.7 Mobile Workforce Management System

Implementing AMI will provide DP&L's customers significant benefits by decreasing meter related field service order activity such as reading verifications, read and leave-on service orders, and disconnect-reconnect orders. However, to maximize the benefits from the Outage Management System and remaining field service order staffing, DP&L needs to implement a new Mobile Workforce Management system (MWMS).

While the existing Dispatch Administration Database system provides a level of efficiency for distributing and collecting field service orders generated by CIS, it does not allow real-time dispatching of priority service orders, service order completion, or generation/dispatch of outage related service orders.

A new MWMS will provide the following capability improvements:

- Generate and dispatch outage orders created by the Outage Management System;
- Display the location of service orders on a geographical electronic map;
- Provide least-cost travel routing for service orders;
- Display real-time vehicle/staff location on a geographical electronic map;

- Provide automated resource allocation based upon vehicle staffing and equipment availability in a geographic area;
- Associate meter-removal service orders with AMI systems and MDM to prevent false outage signals;
- Provide in-field order initialization and automated order completion within CIS;
- Provide real-time service order status with communication to DP&L Call Center staff;
- Provide service order assignment and scheduling based upon resource capability and geographic location.

MWMS takes advantage of the latest advances in mobile devices, handheld PCs, wireless communications and mobile software applications to maximize the utilization and productivity of DP&L's workforce. Automated scheduling and resource optimization, dynamic routing and workflow management, and global positioning and e-maps, combined with real-time communications between DP&L's operations center, call center, CIS, and field service order staff provide significant benefits to provide superior customer service and outage restoration.

Additional benefits from MWMS include:

- Resolving issues with fewer service visits and fewer onsite employees;
- Improving communications to reduce construction and maintenance delays;
- Enhancing employee collaboration;
- Providing service workers with the right equipment and improved skills so they can resolve problems onsite;
- Improving skills transfer from experienced workers to newer employees;
- Creating "paperless" processes to help reduce project delays and increase employee productivity; and
- Enhancing the security of personnel by addressing dangerous situations from the safety of the vehicle.

3.4.8 Distribution Management System

AMI is an enabling technology that provides a wealth of data on distribution system status, loading, and load forecasting. Coupling AMI information stored within the MDM with Geographic Information System (GIS), SCADA, OMS, and eventually substation and distribution automation[3] will be critical to unleash the power of AMI. The DMS project includes support for modeling of distribution substations in GIS and importing one-lines from GIS to be used for SCADA and DMS.

Implementing DMS at DP&L will allow the Company to more efficiently:

- Perform System Analysis, including:
  - Perform extensive scenario/contingency analysis of planned work scope.
  - Make certain that established standards and procedures are followed.
  - Ensure reliability of the system is not compromised by the work planned.
  - Maximize/coordinate the work that can be performed under the clearance
- Plan Daily Operations
  - Understand recent system events and the potential impact to planned scheduled work.
  - Anticipate major events that affect system integrity.
  - Review operational plans and ensure that compliance standards are met.
  - Develop efficient operational plans to reduce impacts on the real-time system environment.
- Manage Planned Events
  - Provide efficient method to generate switching orders.
  - Streamline Clearance management/approval process.
- Analyze Distribution System Optimization supporting a variety of Power System applications
  - 3-ph Power Flow
  - Volt-VAR Control
  - Short-circuit
  - Equipment Condition Monitoring

- Load Survey Balancing
- Feeder Load Balancing and others.

The ability to analyze Distribution System Optimization utilizing near-real-time or actual distribution load data obtained enabled by AMI and stored in the MDMS can provide significant savings through reduction of system technical losses and reduction in future capital expenditures for distribution infrastructure through right-sizing of conductors, substation and distribution transformers, and appropriate timing for circuit/substation upgrades due to load growth.

The integration of OMS, DMS and SCADA at DP&L also provide the following operational benefits:

- One-network model for OMS and DMS analysis;
- Improved operations by close integration of DMS applications with SCADA;
- Increased operator efficiency with one system, eliminating the need to go to multiple systems with potentially different data;
- Integrated security analysis for substation and circuit operations to check for clearance tags in one area affecting operations in the other;
- Streamlined login and authority management within one system;
- Consolidated system support for DMS/OMS and SCADA;
- Simplified data engineering via coordination of SCADA point and GIS data changes.

3.4.9 Service Oriented Architecture

Service oriented architecture (SOA) enables easy automation, data capture and real-time measurement of high-value DP&L business processes such as end-to-end demand-side program management. High-value processes that DP&L automates with SOA will make them easier to control, more visible and more measurable. DP&L and third parties will be able to view processes and manipulate process data in real-time regardless of what multiple applications, systems and organizations they span. Once DP&L's SOA capability is mature, process modifications are quicker and less costly because the work to modify the supporting IT is reduced.

SOA consists of:

- Communications which allow standardized point-to-point communication between systems through widely accepted open standards.
- An Enterprise Service Bus – allows a network of disparate systems to interact as one unified enterprise system by resolving differences in system hardware, software, networks and location.
- An Orchestration Engine / Business Process Management – allows automated integration of separate services to create integrated enterprise-level business processes.
- Business Activity Monitoring – provides end-to-end process performance monitoring and real-time insight and control of DP&L's business.
- A Service Registry (and/or Repository) – provides centralized Service Directory and Management Capabilities that support development-time and deployment-time activities (Publish/Discover) and run-time service look-up capabilities.

Examples of high-value processes from which both the customer and DP&L would benefit as a result of implementing SOA automation are end-to-end energy efficiency and demand response program management, real-time outage management and customer experience management.

3.4.10 IT Infrastructure

AMI infrastructure investment is comprised of three elements: 1. hardware to run applications; 2. disaster recovery and system software to achieve the required user experience; and 3. reengineered IT infrastructure governance and processes to meet required IT service levels.

1. Servers and storage are required to run AMI applications. This hardware must be sized to support required user performance (e.g., screen response time). Program success is risked if undersized hardware makes the systems sluggish. Servers and storage are also required to support development, test and quality assurance environments.

2. DP&L's current disaster recovery capability does not meet the needs of AMI. New disaster recovery hardware and communications are required to adequately support AMI in the event of a business disruption or disaster at DP&L sites. New system software is required to enable the efficient management of applications (i.e., help desk, network monitoring, job scheduling, and configuration management). Use of these tools within the context of refined IT processes enables the reduction of the number of additional IT support staff in IT cost estimates.
3. AMI and smart grid are changing DP&L's business processes and governance model. IT infrastructure processes and governance will need to change too. Current processes, standards, procedures and staffing are engineered to support the current, less prominent use of IT at DP&L today. AMI and smart grid make IT more central to running the business. Business continuity planning must be geared to quicker, more predictable response in the event of a disaster. More users will have more questions on a greater number of systems central to doing their job, so service desk processes and tools should be reengineered. More robust security, identity and access management will be required to deal with the number of new applications, networks, and communication channels that pose unsecured entry risks. Virtualization, consolidation and capacity planning processes and tools ensure that servers and storage are used efficiently without wasted capacity. Virtualization was used in IT hardware estimates to reduce the number of required servers.

4 Cost/Benefit Analysis

4.1 Costs of Deployment

4.1.1 Meters

Meter capital costs include meter hardware, meter installation, incremental DP&L personnel for engineering and project management, and data collection resources to populate our existing Geographic Information System (GIS).

Table 4.1.1.a Meter Capital Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meter Hardware	1,358,733	6,485,802	9,552,019	14,209,264	15,444,852	15,444,852	196,338	62,691,859
Meter Installation	171,864	876,506	1,341,055	2,097,410	2,325,389	2,371,897	31,891	9,216,011
Engineering & Project Management	2,028,805	1,786,144	1,819,453	1,431,361	1,211,276	1,113,291	447,114	9,837,445
GIS	2,250,000	3,000,000	1,750,000	1,750,000	-	-	-	8,750,000
Total	5,809,402	12,148,452	14,462,527	19,488,035	18,981,517	18,930,040	675,343	90,495,316

source: WPH-1.1

The incremental O&M expense associated with the AMI meters comes from two expense categories: (1) Incremental personnel in the Network Operations Center to monitor the additional smart devices and AMI devices in the field. (2) Incremental personnel to analyze the AMI data coming from the network to be able to identify trouble areas and equipment before the customers do, as well as to manipulate the data to be able to understand better the electric load across the network and compare that information to the planned view. This data analysis enables DP&L to keep the AMI network running at peak performance and enables DP&L to realize some of the benefits that will are identified in the operational benefits section. There is no incremental O&M cost associated with the maintenance of the new AMI meters over and above what is already in the DP&L operational budgets for Meter O&M.

Table 4.1.1.b Meter O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
O&M	506,885	1,284,659	1,819,522	2,124,535	2,286,175	2,444,442	2,097,929	12,564,146
Total	506,885	1,284,659	1,819,522	2,124,535	2,286,175	2,444,442	2,097,929	12,564,146

source: WPH-1.5

4.1.2 Communications Network Equipment

AMI communications capital includes hardware and installation and mobile device costs for 2-way voice data network, hardware and installation costs for AMI communications infrastructure, hardware and installation of the microwave IP backbone, and contracted engineers.

Table 4.1.2.a Communications Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
2 Way Voice & Data	10,538,042	3,848,829	235,714	180,300	-	-	-	**14,802,885**
AMI Backhaul	4,245,815	3,056,984	1,907,096	1,899,995	1,922,910	682,440	-	**13,715,240**
Microwave Backbone	10,442,850	7,272,870	-	-	-	-	-	**17,715,720**
Core Telecom Contracted Engineering	4,785,000	2,596,550	408,447	420,700	433,321	446,321	-	**9,090,338**
Total	30,011,707	16,775,233	2,551,256	2,500,995	2,356,231	1,128,761	-	55,324,182

source: WPH-1.3

Communications O&M costs are associated with two key areas: (1) Maintenance cost of the new communication systems being deployed, which is estimated at an annual expense of 5% of the cumulative capital for communications capital previously purchased. This figure covers the out-of-warranty repair costs for hardware, software maintenance fees, vendor call-in support, and the costs to re-install failed equipment. (2) Additional DP&L resources to maintain the new communications equipment in the field.

Table 4.1.2.b Communications O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
O&M	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,125	1,788,074	**10,141,080**
Total	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,125	1,788,074	10,141,080

source: WPH-1.6

4.1.3 Home Energy Displays

We expect to provide Home Energy Displays to customers who do not have Internet access, or approximately 30% of residential customers.

Table 4.1.3.a Home Energy Display Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Capital	-	1,668,142	2,056,121	3,104,146	3,327,147	3,282,929	-	**13,438,486**
Total	-	1,668,142	2,056,121	3,104,146	3,327,147	3,282,929	-	13,438,486

source: WPH-1.2

The O&M for the Energy Display covers out-of-warranty repair, call-in support for DP&L customers and postage for shipping the Home Energy Display to/from the customer.

Table 4.1.3.b Home Energy Display O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
O&M	-	83,407	186,213	341,420	507,778	671,924	671,924	**2,462,667**
Total	-	83,407	186,213	341,420	507,778	671,924	671,924	2,462,667

source: WPH-1.2

4.1.4 IT Systems

Table 4.1.4.a IT Capital Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meter Data and Load Management System	3,531,625	3,210,751	2,744,330	-	-	-	-	**9,486,706**
Customer Information System	11,258,140	17,954,277	12,635,729	-	-	-	-	**41,848,145**
eServices (Website)	724,427	981,652	723,335	-	-	-	-	**2,429,415**
Outage Management System (OMS)	-	-	2,249,677	7,087,195	194,164	-	-	**9,531,036**
Distribution Management System (DMS)	-	-	2,920,942	4,087,556	1,481,716	486,322	318,942	**9,295,478**
Mobile Workforce Management (MWM)	-	-	-	-	6,966,291	2,396,581	460,855	**9,823,728**
SOA	1,840,756	381,937	699,884	936,511	884,178	535,826	-	**5,279,091**
Infrastructure	6,778,248	1,285,721	931	475	284	114	6	**8,065,779**
Total	24,133,196	23,814,338	21,974,828	12,111,736	9,526,633	3,418,843	779,803	95,759,377

source: WPH-1.4, WPH 1-4.1 - 1-4.8

Table 4.1.4.b IT O&M Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meter Data and Load Management System	18,337	146,500	752,863	918,616	919,647	920,712	921,811	**4,598,484**
Customer Information System	206,987	140,638	1,524,500	1,349,809	1,673,852	1,675,790	1,677,790	**8,249,365**
eServices (Website)	3,416	32,336	197,567	355,566	355,965	356,377	356,803	**1,658,031**
Outage Management System (OMS)	-	-	56,021	671,328	516,339	696,326	697,158	**2,637,171**
Distribution Management System (DMS)	-	-	45,835	242,323	491,701	492,270	661,237	**1,933,367**
Mobile Workforce Management (MWM)	-	-	-	-	75,322	360,654	344,530	**780,506**
SOA	32,185	310,862	231,779	554,198	554,820	555,463	556,126	**2,795,433**
Infrastructure	32,842	760,995	1,980,651	3,110,390	3,113,882	3,117,486	3,121,208	**15,237,454**
Total	293,767	1,391,330	4,789,216	7,202,230	7,701,528	8,175,079	8,336,662	37,889,811

source: WPH-1.4

4.1.5 Summary of Total AMI Deployment Costs

Table 4.1.5.a Total AMI Deployment Capital Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meters	5,809,402	12,148,452	14,462,527	19,488,035	18,981,517	18,930,040	675,343	**90,495,316**
Communications	30,011,707	16,775,233	2,551,256	2,500,995	2,356,231	1,128,761	-	**55,324,182**
Home Energy Displays	-	1,668,142	2,056,121	3,104,146	3,327,147	3,282,929	-	**13,438,486**
IT	24,133,196	23,814,338	21,974,828	12,111,736	9,526,633	3,418,843	779,803	**95,759,377**
Total	59,954,305	54,406,165	41,044,733	37,204,912	34,191,528	26,760,572	1,455,146	255,017,361

source: WPH-1

Table 4.1.5.b Total AMI Deployment O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meters	506,885	1,284,659	1,819,522	2,124,535	2,286,175	2,444,442	2,097,929	**12,564,146**
Communications	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,125	1,788,074	**10,141,080**
Home Energy Displays	-	83,407	186,213	341,420	507,778	671,924	671,924	**2,462,667**
IT	293,767	1,391,330	4,789,216	7,202,230	7,701,528	8,175,079	8,336,662	**37,889,811**
Total	1,074,231	3,859,526	8,495,867	11,402,945	12,261,975	13,068,571	12,894,590	63,057,704

source: WPH-1

4.2 Operational Benefits Portfolio

In the assessment of potential benefits that could be achieved through AMI, the Company examined, evaluated, and projected economic realizations in a number of categories.

Reduction in Meter Reading Expense - $11,149,321

AMI would eliminate on-cycle manual and mobile meter reading and associated costs. The benefit value includes all direct meter-reading labor expense, supervisory labor expense, vehicles, equipment, associated building leases, and other miscellaneous materials. Also included are maintenance/upgrade expenses for current meter-reading devices and yearly salary increases for meter readers and supervisors.

Reduction in Energy Theft - $8,833,691

We expect that AMI will reduce energy theft in three ways. First, during deployment, DP&L's vendor will be removing every existing meter and replacing it with a new solid-state meter and the installers will be trained to notice irregularities which can be investigated as potential theft. Second, a tamper-detection capability of new meters will virtually eliminate meter tampering as a source of energy theft, as the meter will provide tamper notification which will be analyzed and potentially investigated for theft. Third, the more sophisticated Meter Data Management System is expected to allow DP&L to better detect bypass and partial-bypass theft through data mining. The total of these three reductions in energy theft is anticipated to save an average of 0.5% of the revenue associated with each residential AMI meter.

Reduction in Uncollected Accounts - $970,120

The effect of the meter's remote disconnect capability on collections is a positive one based on the elimination of estimated readings and reduction in multi-month bills caused by failure to gain access to indoor meters. Most collection efforts center on a regimented process which is affected by missed reads.

Reduction in No Outage Calls - $502,509

This reduction is from a reduction of service calls to investigate customer meters that a customer believes is not performing properly. Since the AMI solution provides the DP&L customer operations team with the ability to look at the real-time meter status there will be a reduction in customer-generated service calls when the system is operating properly.

Reduction of Compensation/Claims for Meter Reading - $1,896,000

Utility costs for workers' compensation associated with injuries incurred by employees during meter reading can be reduced upon adoption of an AMI system, as meter readers would no longer be exposed to high-crime areas, dogs, fences, adverse weather, etc. Costs associated with vehicular accidents occurring during travel between meter-reading locations in the field and utility premises would also be eliminated with AMI systems.

Increased Revenue Due to Improvement in Meter Accuracy - $7,069,353

Electro-mechanical electric meters begin to under record usage with age due to the wearing of the moving parts. Solid-state electric meters do not generally have this problem, and, therefore, average meter accuracy will improve as electro-mechanical meters are replaced. Moreover, solid-state meters fail more conspicuously than electro-mechanical meters and are, therefore, more readily identified. Sample testing of DP&L's electro-mechanical meters from the field have shown an average under usage recording of 0.4%.

Reduction of Bill Processing Costs due to Fewer Exceptions - $268,600

An important AMI benefit is a reduction in billing department resources needed to investigate billing problems and process adjustments. Daily readings from AMI eliminate the need for calculation of estimated bills caused by service contract disputes, back-dated cancellations and turn-ons. Keypunch errors and unusual usage patterns are eliminated or quickly detected by AMI, reducing the need for many of the more difficult billing problems that can occur, and which often take significant clerical time to resolve.

Reduction of Field Service - $3,476,000

Since the AMI system will be capable of obtaining daily readings from all customers, a reduction in the number of field services personnel can be achieved. A high percentage of field work in this category involves obtaining missed meter readings, and turning on and off customer services for cancelled and new accounts. In some cases, a physical shutoff is required, which takes even more time. AMI network services that produce daily readings can accomplish this function without the need for field visits, thereby bringing about a significant reduction in the number of personnel used for this purpose.

The implementation of the proposed AMI system will make the process of turn ons, and shut offs and off-cycle readings much easier on customers as well as resolve many meter access problems. The on-demand-read capability will enable the Company to read meters to issue final bills or initiate service remotely. The increased process efficiency and reduced time to execute the request will make the company much easier to do business with and enhance the overall customer experience.

Again, the reduction in field personnel will produce a corresponding reduction in the need for indoor readings and in the number of vehicles used for these functions.

Deferral of Metering Capital Costs - $79,000

Deployment of AMI would defer the capital costs associated with replacement of meters and other manual meter-reading equipment (e.g., vehicles) that would otherwise have been required. This capital deferral is offset by the annual failure rate of newly installed AMI equipment (e.g., meters, telecommunications).

Reduction of Call Center Contacts for Bill-Related Calls - $650,960

Estimated meter readings often generate customer calls associated with billing issues. With monthly, daily, or more frequent readings from AMI, these missed readings and associated estimated bills can be reduced; thereby decreasing customer call volume, call duration time, and call center agent time spent handling these billing inquiries.

Reduction of Load Research Costs - $316,000

AMI can provide data that can be used for load research studies, thereby decreasing the need for more costly load research metering equipment and services, such as telephone lines and costly field maintenance.

Reduction of Revenue Losses from Unoccupied Premises - $110,600

With the ability to perform daily or more frequent readings, consumption from premises that are supposed to be unoccupied can be more quickly identified and addressed. DP&L will be deploying remote disconnect relays on all residential AMI meters, enabling the power to "inactive" meters to be shut off. This capability will limit utility exposure to write-offs of charges for consumption registered on "inactive" advancing meters on accounts closed after customers inform the utility they are moving out.

Reduction of Meter Testing Costs for New Meter Shipments - $63,200

During the deployment period of the AMI network there will not be a need to test a sample of the new meters shipped to DP&L. The cost of providing factory test information and system validation of all AMI meter deployments is included in the capital costs of the AMI solution.

Total Field Crew Savings from Telecom Upgrades - $884,986

This savings is from lower vehicle and overtime expenses through more efficient dispatch capabilities provided with the new 2-Way Voice & Data network.

Reduction in Existing Two-Way Radio and Microwave System Maintenance - $632,765

This savings comes from the reduction of maintenance expenses of the existing two-way voice and data system and the existing Microwave network after the deployment of the new Microwave and Two-Way Radio networks.

Reduction in Mainframe O&M - $6,588,670

This savings comes from capital improvements and maintenance cost reductions to the existing IT systems that are not going to be spent, given the deployment of the new AMI compatible IT systems that will be deployed during this time period.

Depreciation Savings from Early Retirement of Capital - $8,217,855

Due to AMI deployment we will retire select equipment earlier than expected reducing our total depreciation expense. In addition to meters, select IT will be retired early such as post-2008 software editions.

Table 4.2.1 Summary of Operational Benefits

Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Reduction in Meter Reading Expense	32,670	228,690	638,040	1,296,295	2,166,250	3,119,376	3,668,000	**11,149,321**
Reduction in Energy Theft	27,950	195,647	545,018	1,076,061	1,746,852	2,445,593	2,799,569	**8,836,691**
Reduction in Uncollected Accounts	3,070	21,490	59,865	118,195	191,875	268,625	307,000	**970,120**
Reduction in No Outage Calls	1,388	10,004	28,705	58,375	97,607	140,749	165,682	**502,509**
Reduction of Compensation/Claims for Meter Reading	6,000	42,000	117,000	231,000	375,000	525,000	600,000	**1,896,000**
Increased Revenue Due to Improvement in Meter Accuracy	22,360	156,518	436,014	860,849	1,397,482	1,956,475	2,239,655	**7,069,353**
Reduction of Bill Processing Costs due to Fewer Exceptions	850	5,950	16,575	32,725	53,125	74,375	85,000	**268,600**
Reduction of Field Service	11,000	77,000	214,500	423,500	687,500	962,500	1,100,000	**3,476,000**
Deferral of Metering Capital Costs	250	1,750	4,875	9,625	15,625	21,875	25,000	**79,000**
Reduction of Call Center Contacts for Bill-Related Calls	2,060	14,420	40,170	79,310	128,750	180,250	206,000	**650,960**
Reduction of Load Research Costs	1,000	7,000	19,500	38,500	62,500	87,500	100,000	**316,000**
Reduction of Revenue Losses from Unoccupied Premises	350	2,450	6,825	13,475	21,875	30,625	35,000	**110,600**
Reduction of Meter Testing Costs for New Meter Shipments	200	1,400	3,900	7,700	12,500	17,500	20,000	**63,200**
Total Field Crew Savings from Telecom Upgrade	-	28,563	92,493	163,930	200,000	200,000	200,000	**884,986**
Reduction in Existing Two Way Radio System and Existing Microwave System Maintenance	-	20,423	66,132	117,210	143,000	143,000	143,000	**632,765**
Mainframe O&M Savings	-	-	-	1,556,765	1,614,265	1,675,827	1,741,813	**6,588,670**
Depreciation Savings from Early Retirement of Capital	8,336	241,377	528,604	1,596,931	1,875,216	1,973,509	1,993,881	**8,217,855**
Total	117,483	1,054,683	2,818,216	7,680,445	10,789,423	13,822,779	15,429,601	51,712,630

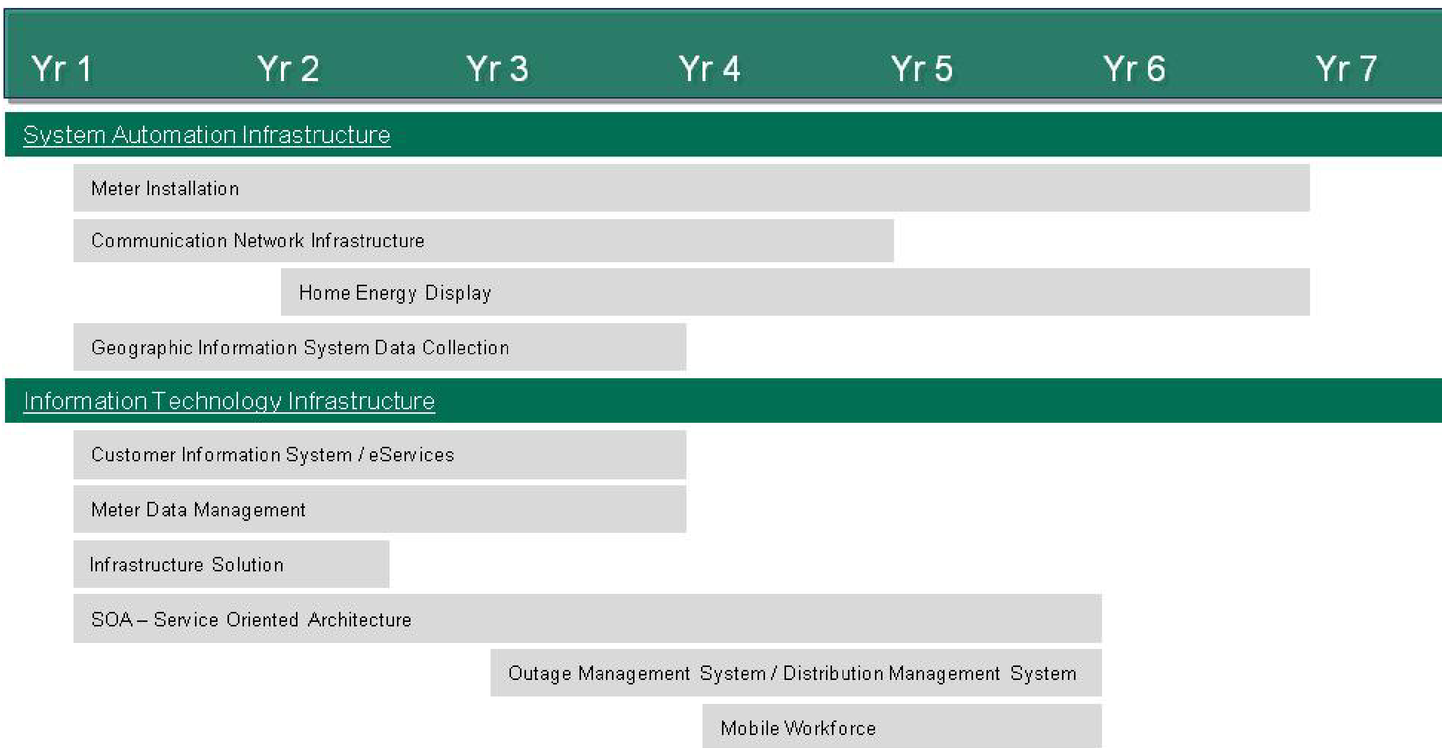
source: WPH-1.4, WPH-1.7, WPH-1.8

5 Implementation Planning

5.1 Deployment Schedule

The Company expects to begin deployment in January of 2009 or upon approval from the Commission. Approximately one hundred percent of meters will be replaced over six years. Core enabling telecommunications will be fully installed by end of year four. While IT systems necessary to support core meter functionality are expected to be in place by the end of year three.

Table 5.1 Deployment Schedule



Appendix A: Technology Assessment

Traditionally, utilities have used single-purpose systems to satisfy specific business needs such as outage management, distribution automation, meter reading, two-way voice dispatch, and general purpose data acquisition. These solutions generally involve a hardware device controlled by a stored program, a communications network (telephone, cellular, powerline communications, Ethernet, or other network service), and an appropriate information reception, execution, processing, and distribution system (data warehouse, back office, head-end, or master station).

Utilities have a fundamental business requirement to read meters so they can render accurate bills to their customers. AMI systems provide the utility with the ability to gather data remotely on consumption and on indications of meter tampering; they can also relay other core meter functions. The chart below lists the additional functionalities that are enabled by migrating from Handheld & Mobile Meter Reading systems to a fixed two-way network that is fully enabled by AMI.

Functionality Available
• Integrated remote service reconnect & disconnect
• Advanced (time-based) rates
• Distributed Generation detection and control
• Remote meter programming
• Net Metering
• Power Quality monitoring/reporting
• Home area network interface
• Enhanced security compliance
• Daily or on-demand reads
• Interval data
• Outage notification
• Load profiling
• Automated monthly reads
• Tamper reporting
• Improved meter read accuracy

The migration from Handheld & Mobile Meter Reading systems to AMI is characterized by a more robust communications means that enable more frequent two-way interaction, both scheduled and by exception, and other functionality between the meter, the MDMS, OMS, DMS, and more traditional backend systems.

Electric meter technology has been evolving and continues to evolve. Along with the transition from electro-mechanical to solid-state devices, meter communication elements have become more available and are becoming less expensive. With the integration of communications, AMI technologies can have functionality beyond the utility's monthly revenue meter-reading requirements. AMI systems open the possibility of integrating a load-limiting functionality, along with the ability to interact with the gas and water meters and other devices in the customer's premises. The industry is moving to communications featuring open architecture and device interoperability. This is critical to achieving these benefits.

While virtual AMI provided by a fixed network is expected to be able to support time-of-use rate forms, the intelligence, processing power, storage, communications, and timekeeping that can be incorporated in AMI-enabled meters can readily support a variety of other time-based tariff programs, such as real-time and critical peak pricing. Further, the AMI facilitates customer price response and participation in energy efficiency and demand response programs. Properly equipped, many AMI devices can interface directly with premises-based devices such as programmable communicating thermostats and other display and interactive devices. Therefore, it is possible for consumers to set simple rules-based actions for their loads and better manage their energy costs through automated control technology. This functionality is a significant enhancement over simple direct load-control functions for both customers and the utility.

AMI also provides better utility oversight of customer performance by enabling the monitoring of the individual load prior to the load control event and measuring the load reduction following a control command. This measurement and verification function adds a greater level of confidence compared to one-way direct load control solutions, where the efficacy of such control efforts can only be measured indirectly after the command is executed and the reduction occurs.

In addition, AMI functionality can enable many utility-centric and operations-related services, including:

- Monitoring some types of distribution system conditions and events, such as power quality disturbances,
- Improving the reporting of electric outage conditions and interruptions,
- Providing additional reliability by remotely disconnecting or limiting and, with safeguards, reconnecting electric service through the addition of an integrated service switch,
- Capturing and reporting time-stamped load monitoring data for system analysis and planning, and
- Providing the ability to remotely upgrade meters or device components without the need to make costly field visits for meter replacements or upgrades. Such upgrades may be due to industry changes to security algorithms, adjustments to daylight savings time (for time-based rate offerings), and the Companies' desire to make changes to operating characteristics and algorithms inherent in these devices.

Communications Technologies

The Company considered several different communications technologies, which are described below.

Telephone and Digital Cellular

A public communications system, such as a standard telephone line or a wireless cellular network, can be used to link individual meters directly to utility back-end systems. While the Company currently uses landline dial-up telephone service for meters on certain types of electric service, the general use of this communications method for a mass-market infrastructure would be costly and problematic due to the customer's tendency to remove the telephone line from the meter on occasion.

Moreover, although the monthly costs of telephone lines have decreased over the years, a trend in the residential market is for the traditional “land-line” to be replaced with a cellular phone, or VoIP phone, thus eliminating the affiliation of a phone number to a fixed location. The costs of a cellular connection have decreased as well. However, the recurring fees for use of this method as a data collection alternative for mass-market meter reading are substantially greater than other network arrangements considered. Nevertheless, both telephone and cellular techniques remain options for special cases where another type of AMI communications is impractical or impossible.

Mobile and Fixed Network Radio Frequency (RF)

In Dayton, DP&L currently uses AMR in a drive-by mode, sometimes referred to as Mobile AMR. This method requires a vehicle equipped with instrumentation capable of gathering meter data to be driven past meters that are equipped with a low-powered RF module operating on an unlicensed frequency. The meters (either gas or electric) can either be awoken to broadcast information (this is the typical arrangement with battery-powered units in gas and water meters) or they can continuously broadcast or “bubble up” their information (this is the more typical method for electric meters where the power consumption of the RF module is not an issue). Because of the need to pass near each meter to obtain its reading, Mobile AMR is typically used for reading meters once each billing cycle.

A “fixed network” is established in an area with RF-based AMR meters with the installation of collectors located on utility pole tops, utility towers, or similar structures. The network can then effectively operate as a remote collection system, that is, one that is capable of gathering information from meters on a more frequent basis and of communicating this data to the master station and responding to requests for meter data that are locally stored at the collector.

RF Mesh

In this technology, the meters have the ability to relay data both from their own registers and from other meters. This arrangement creates a network among end-points through meter-to-meter communications. This interconnected network is used to extend the range of the AMI modules, optimize the communication paths, and reduce the number of pole-top data collectors required (as compared to the fixed AMR network described above). Communications reliability is generally improved because the messages are not assigned a specific path but can be routed through the "best" path in the network at the time of transmission. By designating key points in this mesh network as "take-out points," this configuration can reduce the total number of collectors and master-station relay points (concentrators) that would otherwise be required in a more typical fixed network. These take-out points are typically mounted on utility poles or similar structures and sometimes in designated meters that have wireless backhaul built into them.

RF Point to Multi-Point

AMI systems in a Point to Multi-point architecture use higher-powered RF modules operating in a licensed frequency to communicate with data collectors. Systems with this configuration can enable a full two-way network. Additional functionality, such as soliciting an ad hoc individual meter-reading interrogation, querying the meter to provide information on power quality, and communicating directly with individual peripherals, is based on such a system's capability to send information to or receive information from specific points. This higher-powered configuration can communicate directly with many more meters and requires fewer but commensurately more costly radio transceivers than a fixed network or a RF mesh network and are typically installed on communications towers. The Point to Multi-Point system do have an advantage of less backhaul points and ongoing operational costs to get the data to the back end utility IT systems.

Broadband over Powerline (BPL)

Solutions are available that can enable a high-capacity data network to be created in the existing electrical infrastructure. These "broadband over powerline" networks provide high-speed connectivity. Many utilities indicate a growing interest in and early use of these techniques for utility-oriented services such as electrical distribution asset monitoring, substation video surveillance services, and AMI. However, this communications technique has a high level of uncertainty both in technical and total functionality in the network distribution grid. Since BPL is still evolving and the Companies' evaluation of this technique is in the early stages of feasibility studies, this method was eliminated from consideration in the Company's current business case. Although BPL may be viable in radial distribution networks, the present costs of this communications infrastructure and the greater cost of BPL-enabled meters make this technology significantly more costly than the other AMI methods considered.

Powerline Carrier (PLC)

PLC likewise uses the existing electrical distribution network as a means to communicate to and from meters. However, this technology operates at a lower frequency range, providing a very low-speed and high-latency communications network. This system uses vendor-supplied coupling equipment and sensors at key points within the distribution network. These devices communicate with meters that contain the powerline signal decoding and modulating unit. When a specific meter that corresponds to a designated address (or group of meter addresses) is interrogated, it interprets the respective command and sends a message (or messages) in response to this poll.

For other devices that are not connected to the power line, such as gas or water meters, a low-power radio transceiver included in an adjacent or nearby electric meter may allow the electric meter to act as a gateway or relay for these other devices. This secondary RF-link enables the utility to communicate, albeit indirectly, with gas meters, water meters or customer-premises devices, such as thermostats or other peripherals.

At the substation, there is a communications link that provides a data path to the back office. This link can use any common data network means that is appropriate, including, but not limited to, telephone landline, wireless telephone, WiFi, Microwave or other WAN connection.