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FILE

OCC EXHIBIT NO. _____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan.	)))	Case No. 08-1094-EL-SSO
In the Matter of the Application of the Dayton Power and Light Company for Approval of Revised Tariffs.	)))	Case No. 08-1095-EL-ATA
In the Matter of the Application of the Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code § 4905.13.	))))	Case No. 08-1096-EL-AAM
In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Amended Corporate Separation Plan.	))))	Case No. 08-1097-EL-UNC

DIRECT TESTIMONY
of
STEVEN W. PULLINS

ON BEHALF OF THE
OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad St., Suite 1800
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January 26, 2009

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DEFINITIONS

Abbreviation	Definition
IEEE	Institute of Electric and Electronics Engineers
MGS	Modern Grid Strategy
U.S. DOE/NETL	U.S. Department of Energy's National Energy Technology Laboratory
AMI	Automated Meter Infrastructure
IT	Information Technology
ADO	Advanced Distribution Operations
ATO	Advanced Transmission Operations
AAM	Advanced Asset Management
MDMS	Meter Data Management System
DR	Demand Response
SA	Substation Automation
OMS	Outage Management System
DMS	Distribution Management System
PHEVs	Plug-In Hybrid Electric Vehicles
MWM	Mobile Workforce Management System

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A1. My name is Steven W. Pullins. My business address is 2126 Southwood Drive, Maryville, Tennessee, 37803. I am the President of Horizon Energy Group LLC.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. I have a BS in Engineering Physics from Wright State University and a MS in Nuclear Engineering from the University of Wisconsin. In addition, I completed the Chief Engineer Officer certification program for U.S. Navy Nuclear Submarines. I have more than 30 years of energy industry experience in operations, maintenance, engineering, and project development. I currently lead the nation's Modern Grid Strategy ("MGS") for the U.S. Department of Energy's National Energy Technology Laboratory ("DOE / NETL"). I have worked with more than 20 utilities in Smart Grid strategies, renewables strategies, power system optimization, operations transformation, RTO/ISO operational processes, automated meter infrastructure ("AMI"), Smart Grid technologies, and strategic and resource planning. I have worked for utilities and utility service providers and founded Horizon Energy Group in 2005 to tackle the difficult issues of change in the electric and gas utility industries.

Q3. PLEASE DESCRIBE YOUR EXPERIENCE DIRECTLY RELATED TO THE TOPICS DISCUSSED IN YOUR TESTIMONY.

A3. As mentioned, I have led the DOE / NETL Modern Grid Strategy ("MGS") team for more than 3 years which has been intimately involved in developing the nation's approach to Smart Grids and incorporation of AMI. This effort includes advice that the MGS team provided to the Public Utility Commission of Ohio ("Commission" or "PUCO") during its series of 2007 workshops on AMI. This included my partner, Joe Miller, advising the Commission staff on the preliminary plans submitted by the four Ohio investor-owned utilities last year (2007). I personally worked on various aspects of Smart Grid and AMI planning for six years at several utilities, including San Diego Gas & Electric, Consumers Energy, Puget Sound Energy, Southern California Edison, Great River Energy, Entergy, Salt River Project, TVA, Taiwan Power, Southwest Power Pool, Midwest ISO, and California ISO. I have conducted four Smart Grid studies in the U.S., three of which I led, and am currently leading the first state-wide Smart Grid Implementation Plan in West Virginia. I am the Secretary of the Institute of Electric and Electronics Engineers ("IEEE") Power & Energy Society Intelligent Grid Coordinating Committee. I would also like to note that Joe Miller has been actively supporting the efforts of the Director, Federal Smart Grid Task Force, Eric Lightner, and the FERC-NARUC Smart Grid Collaborative led by Commissioner Butler of New Jersey. In addition, Joe Miller and I are frequently sought to speak at national and international conferences on AMI and Smart Grid issues, from technology, strategy, regulatory, and financial perspectives.

Q4. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A4. No. This is my first submitted testimony before the Public Utilities Commission of Ohio.

Q5. WHAT DOCUMENTS HAVE YOU REVIEWED IN THE PREPARATION OF YOUR TESTIMONY?

A5. I reviewed Book II of Dayton Power and Light's ("Company" or "DP&L") ESP filing including working papers. I also reviewed Company responses to OCC discovery as of the date of this filing.

II. PURPOSE OF TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. This testimony is being submitted to provide the results of my review of the DP&L's AMI and Smart Grid program. I will focus my discussion points on several issues, including:

- AMI per meter costs
- Inclusion of Information Technology ("IT") System costs in AMI
- Under-estimating the Operational Benefits
- Over-estimating the costs of Substation Automation
- The significant costs of Communications included in AMI
- Societal and Operational Benefits comparison

- Cost calculations for the IT Systems
- Development of an Accountability Plan

III. AMI COSTS

Q7 HOW DO YOU DEFINE AMI?

A7. Under the DOE/NETL Modern Grid Strategy, AMI is one of four milestones in delivering the Smart Grid. AMI, advanced distribution operations ("ADO"), advanced transmission operations ("ATO"), and advanced asset management ("AAM") are the four milestones. Each milestone consists of several applications and systems that deliver the milestone. Advanced metering infrastructure delivers a metering function, a consumer portal function with access by consumer and utility, a two-way communications function, and a transactional function.

Q8. IN YOUR DEFINITION OF AMI, WHAT ARE THE SPECIFIC COMPONENTS FOR DEPLOYMENT?

A8. The key components for AMI include a smart meter that provides operational and consumer information including energy (kilowatt-hours), demand (kilowatts), voltage, current, power quality information and other features, a network communications infrastructure that supports two-way data flow end-to-end, a near-real-time portal for the consumer and utility to explore the energy trends, specific time data, and data management connection to or integration with transactional systems for customer information, billing, outage data, asset management, and other knowledge-based purposes.

Q9. BASED ON YOUR EXPERIENCE AND EVALUATION OF OTHER AMI DEPLOYMENTS, WHAT IS THE AVERAGE "ALL-IN" COST PER METER FOR A STANDARD AMI SCOPE?

A9. Based on my experience, the average "all-in"[1] cost per meter for a standard AMI scope is approximately $250. This average comes from using industry data from several utilities, including Consumers Energy, San Diego Gas & Electric, Southern California Edison, Public Service Gas & Electric, and others, and includes smart meters, end-to-end two-way communications infrastructure, remote connect/disconnect switches, consumer portal interface, and integration of a meter data management systems with enterprise applications.

Q10. HOW DO DP&L'S "ALL-IN" AMI COSTS COMPARE WITH OTHER INSTALLATIONS AROUND THE COUNTRY?

A10. Table 1 below shows that DP&L's "all-in" AMI costs seem extremely high at $486/meter (taking the entire AMI cost of $255 million divided by 523,000 meters). When DP&L's costs are adjusted to reflect the standard AMI scope to give an apples-to-apples comparison, its "all-in" recoverable cost per meter is approximately $270. The difference between the $270 cost per meter between DP&L and the industry average may be due to the differences in the

1 Meter, communication, consumer portal, disconnect, installation, engineering, and project management.

communication network. The merits of DP&L's communication approach are discussed later. Table 1 provides a breakdown of the components of the "all-in" AMI cost per meter; column 1 contains DP&L's "all-in" cost per meter as filed; column 2 provides an IT adjusted "all-in" cost for a standard scope AMI; column 3 provides an "all-in" standard scope AMI adjusted based on industry standard IT and communication costs.

Table 1: AMI Capital Cost Comparison: Average "All-In" Cost Per Meter:
Capital Cost Comparison

Investment Element	DPL Cost ($ millions) as Filed	DPL Cost ($ millions) for Standard Scope AMI Adj. for IT	DPL Cost ($ millions) for Std Scope AMI Adj. for Comm
Smart meters	$62.10	$62.10	$62.10
Installation	$9.20	$9.20	$9.20
Eng/Project Management	$9.80	$9.80	$9.80
Communication	$55.30	$55.30	$40.80
MDMS/IT	$117.90	$4.80	$4.80
Total	$254.30	$141.20	$126.70
Total Meter Count	523,000	523,000	523,000
Ave Cost ($/Meter)	**$486**	**$270**	**$242**

Q11. WHAT IS THE IMPACT OF THE IT SYSTEMS COSTS ON AMI?

A11. The difference between the DP&L "all-in" AMI cost of $486/meter and its "apples-to-apples" "all-in" AMI cost of $270/meter is DP&L's inclusion of a large number of IT Systems in the cost. The FERC August 2006 report on "Assessment of Demand Response and Advanced Metering – Staff Report," shows IT to be 9% of AMI system cost, whereas DP&L approaches 41% of system cost. I agree with this Assessment. If I were to apply the expected 9% of AMI system costs to DP&L's proposal, it would equate to $22.96 million verses the current $104.6 million, a difference of $81 million. Below, in Table 2, is a comparison of the FERC staff report findings with the DP&L filing:

TABLE 2: AMI Related Cost Percentages

Cost Component	FERC Summary	DP&L Filing	Remarks ($ millions)
Endpoint Hardware	45%	30%	Meter Capital ($74.4) less Project Management ($5.8) and Engineering and Installation ($10.3)
Network Hardware	20%	13%	Comm Capital ($32.7) less Project Management ($6.4) and Engineering and Installation ($16.2)
Installation	15%	11%	Install costs + engineering costs ($26.5)
Project Management	11%	5%	$5.8 + $6.4
IT	9%	41%	IT Systems ($95.8) + GIS ($8.8)

Nearly all AMI programs at utilities in the U.S. include a new Meter Data Management System ("MDMS"), and some include a load management system to manage the operations of Demand Response ("DR") initiatives; however, few include initiatives to upgrade other related enterprise systems or consumer side technologies. DP&L has taken a different approach by including the following IT systems in their AMI program:

- Home Energy Displays

- Customer Information System / Billing System
- Advanced Outage Management
- Mobile Workforce Management
- Distribution Management System
- Service Oriented Architecture
- IT infrastructure
- Geographical Information System (field audit only)

Inclusion of these IT systems greatly increases the cost of the AMI program cost per meter as the AMI scope is currently defined in the filing. While DP&L's operations should benefit in efficiency and effectiveness from transforming the IT systems, it is not clear how the consumer or DP&L will quantitatively benefit from such IT system upgrades - it is also not clear what portion of the IT costs should be included in this filing verses a distribution case filing. To more clearly understand the actual allocation of costs and benefits, I recommend that the PUCO require the Company to modify the "Operational Benefits Portfolio" presented in section 4.2 of Chapter 3, by breaking it down to the same level of detail as the IT cost categories, relating cost and corresponding benefits for each investment category. DP&L should also provide support and analyses for these costs, which it has not done.

Q12. IS DP&L UNDER-ESTIMATING THE OPERATIONAL BENEFITS OF AMI / SMART GRID DEPLOYMENT?

A12. Yes, based on my experience with AMI and Smart Grid implementations. Generally, the operational benefits in "Operational Benefits Portfolio" can be achieved by deploying the "***standard AMI scope***" without the additional IT investments. A "standard AMI scope" usually includes:

- Smart Meters
- 2-way communication infrastructure
- Meter Data Management System (MDMS) which interfaces with enterprise systems
- Interface with consumer side technologies, commonly referred to as consumer portal technologies

There are two benefits listed in the portfolio that ***do*** relate to the additional IT investments:

- Reduction in Mainframe O&M - $6.6 million
- Depreciation Savings from Early Retirement of Capital (meters & IT) - $8.2 million

Both of these benefits generally relate to savings associated with the IT side of these investments and not AMI. Niether appear to be related to the actual "operation" of the field side processes. Implementation of these new IT systems that are significantly above and beyond the standard scope AMI can be considered distribution in nature. The inclusion of the IT scope as currently filed will result in significant improvements in associated business processes that will improve the execution of the work performed by the Company's staff when managing outages, improving customer satisfaction, and managing the work forces. These benefits do not appear to have been included in the Operational Benefits Portfolio or the Societal Benefits listed on WHP-1.9. An under-representation of operational benefits will result in a greater burden on the customer given the nature of recoverable net of benefit based rider. A clear breakdown of both the costs and benefits for each investment category is needed to clarify and assist in the identification of any additional gaps.

Q13. ARE THERE OTHER AMI OR SMART GRID COSTS THAT YOU BELIEVE ARE OVER-ESTIMATED?

A13. Yes, based on my experience with AMI and Smart Grid implementations. Upon reviewing the cost of Substation Automation ("SA") as described in Book II, Chapter 1, Table 2.3.2.a, the $22 million capital cost of automating 49 substations would average $450,000 per substation, excluding the cost of enabling microwave and AMI backhaul in the substation which is accounted for in the Communications Capital Cost. From my personal experience with seven utility-wide substation automation deployments ranging in scope from one substation to 180 substations, the typical substation automation project in the industry over the last several years has averaged $180,000 to $220,000 not including the cost of communications.

The more sophisticated EPRI Intelligrid automated substation, which I reviewed in December 2008 for another utility, costs approximately $270,000. Therefore, the DP&L cost estimate is very high by comparison as is exhibited in the following table displaying total SA cost for the 49 substations.

TABLE 3: Substation Automation Cost Estimates

DP&L SA ($450,000/SA)	Industry Average ($220,000/SA)	Industry High SA ($270,000/SA)	Potential Savings ($ millions)
$ 22.05 million	$ 10.78 million	$ 13.23 million	$ 8.82 - $11.27 millions

In the following table, I have provided a breakdown of the substation automation components per workpaper, WPI-1.2, SA Capital, indicating DP&L's percentage of cost to total substation cost and provided recommended percentage ratios.

TABLE 4: Substation Automation Components

Capital Element	Average Cost / Substation	Percentage of Cost	Recommended Percentage of Cost
Engineering	$115,000	26%	5%-10%
Installation (Technicians)	$71,000	16%	11%
Communications Gateway	$29,000	6%	3%
Upgrade Pilot Wire	$67,000	15%	11%
SCADA Telecom Equipment	$64,000	14%	None (potential double counting)
New Relays (~30 / substations)	$104,000	23%	18%
Total	$450,000	100%	

The SCADA telecommunications equipment appears to be a duplicate to the AMI Backhaul system in communicating protected, important data between the substation and a central corporate location. It is traditional to separate SCADA communication paths from all other communications, however in an AMI / Smart Grid environment, there is no difference in criticality and security of data between that coming from smart meters and smart substations. Therefore, one backhaul system can be used rather than developing duplicate backhaul communications paths.

Commercial hardware-based projects typically have 5 to 10% engineering costs; the higher end being for more technology rich projects. An engineering cost of 26% per substation is high, especially when considering that these 49 substations will be almost identical in Substation Automation, SCADA, and communications architecture. The basis for DP&L's estimate for the engineering needs clarification. Upgrading the pilot wire to support protection schemes is appropriate, but the cost is high considering that this is a multiple substation roll-out and there are above average installation costs (15% versus 11%) already included in the SA cost.

Thirty new relays, assumed to be digital, per substation is high by comparison to the industry average as indicated in Table 3. There is not enough detail to understand if there are particular DP&L substation designs that require a large number of relays. In summary, the cost for Substation Automation is high when compared to other installations in the industry. To clarify, DP&L should compare its Substation Automation costs to these other installations and identify the differences.

IV. COMMUNICATION COSTS

Q14. YOU PREVIOUSLY MENTIONED THE HIGH COMMUNICATION COSTS. IN WHAT WAY ARE THESE COSTS HIGH?

A14. The communications costs in the DP&L filing consists of four parts: (1) two-way voice and data system, (2) microwave midhaul from two-way data system to the substations, (3) AMI backhaul from the substations to a corporate location, and (4) core telecommunications outsourced engineering for AMI. Some of the costs are above what is typically seen in the industry.

For the Communications Network portion of the AMI Program, there is an unusually high project management cost ratio. The total Communications Capital cost of $55.3 million has vendor and DP&L project management costs in each of the three communications elements.

TABLE 5: Communications Network Costs: Project Management ($ millions)

Communications Element	Capital Cost less Project Management	Project Management	Project Management Percentage
Two-Way Voice & Data	$13.2	$1.6	12%
Microwave	$15.5	$2.2	14%
AMI Backhaul	$11.1	$2.6	23%
Core Telecom Engineering	$9.1		
Total	$48.9	$6.4	13%

Project management in the commercial sector should be 4 to 5% as exemplified in the DP&L overall AMI project, a potential savings of $4 million from the $6.4 million in Table 5. In the communications capital costs, as depicted in Table 5, the project management cost is more than twice the typical cost. It appears that DP&L is stacking project management costs, i.e., vendors and internal staff versus splitting project management duties.

Commercial hardware-based projects typically have 5 to 10% engineering costs; the higher end being for more technology rich projects. The DP&L communications project is much higher than expected, as depicted in the table 6. DP&L shows a 36% engineering capital cost on the engineering component of the communication system. There is no justification for this high percentage. Assuming the higher 10% engineering cost component would yield a potential savings of $10.5 million. It is doubtful that DP&L would accept such high engineering costs on a typical technology project.

TABLE 6: Communications Network Costs: Engineering ($ millions)

Communications Element	Capital Cost less Project Mgmt and Engineering	Engineering	Engineering Percentage
Two-Way Voice & Data	$12.4	$0.7	6%
Microwave	$13.1	$2.4	18%
AMI Backhaul	$8.7	$2.5	28%
Core Telecom Engineering		$9.1	
Total Capital less Engineering	$40.6	$14.7	36%

V. OPERATIONAL AND SOCIETAL BENEFITS

Q15. YOU PREVIOUSLY MENTIONED THE IMBALANCE OF OPERATIONAL BENEFITS AND SOCIETAL BENEFITS. IN WHAT WAY ARE THESE BENEFITS IMBALANCED?

A15. DP&L has defined operational benefits as those that are enjoyed by the utility and lists them in the "Operational Benefits Portfolio". It defines societal benefits as those that are enjoyed by the customers and society and identifies them on Exhibit KLH B-1 and WHP-1.9. As discussed above, some operational benefits that result from the implementation of the IT investments seem to be missing. Consequently the operational benefits that flow to DP&L are unbalanced.

DP&L will recover its costs for AMI and Smart Grid investments through riders EIR and IIR and through operational savings. These mechanisms are clearly defined and quantified in the filing. Specific societal benefits will be enjoyed by customers but the specific mechanisms that will be used to create a positive value proposition are not as clearly defined. How, specifically, will consumers take advantage of the opportunity to reduce their energy bill? What guarantee will be given to customers on how much their individual outage duration and frequency will be reduced and power quality improved? How will customers realize other values from the smart grid such as increased choice and new options for engaging with electricity markets? These questions must be answered before the program is rolled out.

Both the costs and benefits for AMI and Smart Grid should be comprehensive and allocated to the appropriate beneficiary to ensure the cost recovery mechanisms are correct for DP&L and the value delivered to the customer is clear and achievable.

Based on the previous operational benefits and societal benefits analyses conducted by other utilities or regions in the US associated with a Smart Grid, there is near economic balance between the accumulated benefits to the utility and to consumers / society. As currently presented, the operational benefits for DP&L are $80 million, over 15 year time period, compared to societal benefits of $682 million (Exhibit 3.2.2.b and KLH B-1) resulting in a ratio (societal to operational) of over 8 to 1 – significantly higher than what I have seen in other cases. Given this ratio, the share of the cost for the AMI/Smart Grid investment will be tipped toward the consumer paying the larger majority. A clearer accounting of what the benefits are (both operational and societal), and who the beneficiaries are, is needed to more accurately determine if the allocation of costs and benefits are appropriate. Based on my experience, I would expect the ratio of societal to operational benefits to be closer to 1. For example, Table 7 below shows a comparison of DP&L benefits to those publicly available in the San Diego Smart Grid Study[2], it is apparent the DP&L benefits are significantly imbalanced[3].

TABLE 7: Societal and Operational Benefit Ratio

	DP&L Filing	San Diego Smart Grid Study (publicly available Smart Grid study)
Study Period	2015	2025
Customer count	523,000	1,300,000
Capital Cost of Program ($ millions)	$297	$490
Operational Benefits ($ millions)	$80	$1,433
Societal Benefits ($ millions)	$682	$1,396
Societal / Operational Benefits Ratio	8.53	0.97

Certain benefits from AMI / Smart Grid can be considered either societal, operational, or both, such as the following: (1) improved asset utilization efficiency, (2) enhanced service quality which includes outage reduction benefits,

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[2] http://www.gridwise.org/pdf/061017_SDSmartGridStudyFINAL.pdf

[3] The San Diego example is based on a 20-year period compared to DP&L's 6-year recovery period. Given the varying time periods, an evaluation would show an increase in the operational benefits relative to the societal benefits, but it would not substantially change the benefit ratio.

and (3) distribution network efficiency. These benefits are included in Societal Benefits, which is true, but the utility operations also benefit from such improvements.

Other operational benefits that should be included, but are not, are listed in the DP&L responses to OCC's Interrogatories No. 360, 362, 368, and 369[4]; this includes (1) use of AMI information for the OMS to determine outages, (2) use of AMI information in the DMS and distribution planning to enhance Volt/VAR optimization process, (3) use of AMI information to automatically close out work orders, (4) use of AMI information to measure existing load under DR and load shedding action, (5) use of the AMI system to track power flows in both directions for DG and PHEVs, (6) use of AMI and OMS to improve system metrics, SAIDI and SAIFI, and (7) use of AMI, OMS, and MWMS to reduce time to dispatch trouble crews and reduce outage duration. This is just a sample list, but it shows that the currently filed Operations Benefits portfolio is lacking key benefits.

Q16. DO YOU HAVE ANY OTHER OBSERVATIONS OR COMMENTS CONCERNING THE SOCIETAL BENEFITS THAT DP&L HAS CALCULATED?

A16. Yes, I noticed several weaknesses in the calculation of the Societal Benefits in the Workpaper WPH-1.9. It is in DP&L and the consumers' best interest to correct

[4] See Exhibit SWP - 1.

these weaknesses before considering approval the AMI / Smart Grid program. I would like to share these questions and observations.

First, in WPH-1.9, row 18, regarding the Total Non-Weather Related Outage Time for Outages over 10 minutes, DP&L has not made it clear which IEEE 1366[5] definitions and recording requirements it is utilizing to estimate the outage improvement metrics. Also, the consumer and society benefit from enhanced service quality during <u>weather related</u> events as well, not just during non-weather related events. AMI and Smart Grid deployments reduce the overall outage durations of weather outages even to a greater degree than non-weather related outages. The Total Outage Time over 10 minutes, for weather-related and non-weather related outages, should be used for this calculation.

Second, in the same row 18, industry feedback shows that momentary outages, that is, interruptions less than 5 min per IEEE 1366, at strongly digital-based businesses and industries severely impact business operations. EPRI studies have shown that this Power Quality event can create financial damage in the US as high as $24 billion/year[6]. Smart Grid deployments can reduce the number of momentary outages which should be accounted for in the Societal Benefits for DP&L's commercial and industrial customers.

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[5] IEEE guide for electric power distribution reliability indices, IEEE Std 1366, 2001 Edition.

[6] U.S. DOE/NETLI, "A System View of the Modern Grid, Provides Power Quality for 21st Centry Needs," January 2007, pg A4-9.

Third, in WPH-1.9, row 30, regarding the percentage of customers on circuits with adequate ties, DP&L shows 67% of the customers are on adequate ties based on "DP&L Estimates." It is not clear whether automated ties include automated switches? If the ties are manually operated, or even remote-manual operated, it does not meet a Smart Grid characteristic. Only when the distribution circuit has the ability to autonomously take action at a few sectionalizing points based on direction from the distribution management system and associated sensors, should it be considered adequately tied. Based on US industry data, it is more likely that only 15% of DP&L distribution circuits currently meet a Smart Grid characteristic for autonomous action[7]. This difference suggests a misunderstanding of distribution circuit automation value in general. Further, in row 31, regarding the percentage improvement in outages, DP&L shows 33% based on "DP&L Estimates." For the DP&L benefit calculation this is an important variable and should be based upon data and an analysis.

Fourth, in WPH-1.9, row 32, regarding Total Outage Reduction, DP&L calculated a value of 22% by dividing line 30 by line 31 according to the notes. However, multiplying line 30 by line 31 yields 22%. Further, when using this percentage in row 33 to calculate the distribution automation Reduction per Customer outage minutes, DP&L yields a value of 15.2 minutes which is the current average Outage Time per Customer of 69 minutes multiplied by 22%. The note says this number is "FERC Data." The Company should provide this reference for review.

[7] UtiliPoint. "2006 UtiliPoint International Report." 2007.

Fifth, in WPH-1.9, when reviewing the entire calculation in rows 30 through 33, it shows the estimate of Total Outage Reduction is flawed. A proper development of the Total Outage Reduction would include a determination of the recovery time value of autonomous sectionalizing of distribution circuits, assessing the recovery time of non-affected sections and circuits to the total, and estimating the average number of customers on a section. My experience with international companies such as Taiwan, Japan, Singapore and Scotland shows that automated distribution circuits managed by a Distribution Management System result in systems average outage durations of a few minutes or less. For example, Taipei Power Company in Taipei, Taiwan, realized a significant improvement in average outage duration. After Advanced Control Systems installed DMS, they went from an average outage duration of 58 minutes to less than one minute. Following a Smart Grid deployment, DP&L should see at least an order of magnitude drop in SAIDI and CAIDI. Thus, Row 33 should be roughly 62 minutes instead of 15.2 minutes. This greatly increases the Enhanced Service Quality portion of the Societal Benefits from $91 million (NPV) to approximately $360million (NPV). Plus, when properly accounted, it will greatly increase the Operational Benefits.

Finally, monetizing societal benefits is a difficult task requiring rigor and discipline in the scoping, calculating, and sourcing. The basis of assumptions needs to be debated and well understood to include in the analysis.

Q17. DO YOU HAVE ANY OTHER OBSERVATIONS OR COMMENTS CONCERNING THE COSTS THAT DP&L HAS CALCULATED?

A17. Yes, the Book II spreadsheets do not fully answer the questions about how IT costing was done. Section 1.4 in the "Final Workpapers" spreadsheet breaks down major costs in Sections 1.4.1 – 1.4.8, but nothing specific is addressed in either the main Application, Section 3.4 of Chapter 3 (p.16 – p.30) (p.110 – 133 in part 2/6), or in Karen Garrison's direct testimony, which makes reference to specific RFPs, industry benchmarks, or internal estimates, which were not part of the application.

One area of concern is the high level of IT cost compared to most projects. The IT cost, converted to a per-meter basis is roughly $183/meter in capital costs and $73/meter for operating and maintenance costs ("O&M"), which represents a significant part of the total AMI project capital and O&M costs. This is derived from taking the Total Capital Costs and the total O&M Costs in WPH 1.4 over the total number of meters. This represents 38% of total project capital costs and 60% of O&M costs. Based on my experience the overall IT System costs are higher than expected.

The following table summarizes the IT costs as presented by DP&L. DP&L should be required to insert a range of market prices for each IT application based on what they found in their estimating process and to explain any significant variance between their estimates and the average market price for each IT application. Additionally, an investment in such a comprehensive suite of IT applications should also bring a discount over the prices individually.

TABLE 8: IT Costs Summary ($ millions)

IT Component	DP&L Total Capital Cost Estimate	Market Price Total Capital Cost Estimate	Variance Explanation
Home Energy Displays	$13.5	$14	DP&L appears to be on-target with Home Energy Displays, or even a little low (installation costs do not appear to be included). Reference pricing for HED's are about $100-$125 / unit.
CIS/Billing	$40.5	$40	On-target
eServices (Website)	$2.4	$2 - $3.25	On-target
Meter Data and Load Management System	$9.2	$9.9	On-target
Advanced Outage Management	$9.4	$1	
Mobile Workforce Management	$9.4	N/A	
Distribution Management System	$8.7	N/A	
Service Oriented Architecture	$4.9	N/A	
IT Infrastructure	$7.9	N/A	
GIS	$8.8	N/A	This is an as-built walk-down, DP&L already has GIS technology
Totals	**$114.7**	**$68.1**	

DP&L already has a GIS so the cost listed above is assumed to be for performing a field audit to re-baseline the features of GIS. Normally this is done when a utility loses control of its configuration management system for facility mapping. DP&L should clarify why they are including these costs as part of AMI.

As discussed above, IT application costs should be connected to the specific benefits each application yields. For example, OMS systems alone can drive over $400,000/year in O&M savings when integrated with AMI projects[8]. These can also offer additional improvements in reliability and outage metrics. As another example, some MWM systems can yield savings of $3000/supervisor and $750/employee annually. Some systems have yielded a full return on investment in as little as 6 months.[9] Other sources say that CIS/ MWM combinations will save up to $1 million a year.[10]

VI. SUMMARY

Q18. PLEASE SUMMARIZE YOUR POSITION CONCERNING THE DP&L AMI / SMART GRID PROGRAM.

A18. The DP&L AMI / Smart Grid Program as filed has most of the merits of a good, cost-effective AMI / Smart Grid program that addresses the program

[8] See http://tdworld.com/distribution_management_systems/power_amr_improves_outage/.
[9] See http://www.passportcorp.com/shared/Mobile%20Workforce%20Management%20White%20Paper.pdf.

[10] See http://www.utilityproducts.com/display_article/342357/129/none/none/Indus/City-of-Charlotte-Integrates-Mobile-Workforce-Management-with-CIS-to-Improve-Customer-Service,-Reduce-Cost-to-Serv.

characteristics of a Smart Grid commonly envisioned by industry, policy, and technology leaders. This is "potentially" a very good step in the right direction; however, specific areas, such as cost data and analysis and benefit adjustments still need to be addressed before PUCO approval can be recommended and the programs proceed:

- DP&L needs to properly account for the Operational Benefits and Societal Benefits so that the imbalance from under-estimating the Operational Benefits of a Smart Grid is properly accounted for;
- DP&L should develop an Accountability Plan;
- Justification through Operational and Societal Benefits accounting for including the IT Systems should be required;
- The Plan should properly align costs with associated benefits, and beneficiaries:
- Modification of the communications system costs should be required to bring the costs in alignment with industry norms.;
- Modification of the unusually high substation automation costs should be required to bring the costs in alignment with industry norms; and
- The GIS field audit should be removed from this particular filing.

A. Operational Benefits and Societal Benefits Imbalance

I would like to reiterate that a clearer accounting of benefits (both operational and societal), and who the beneficiaries are, is needed to more accurately determine if the allocation of costs and benefits are appropriate. I would expect the ratio of societal to operational benefits to be closer to 1.

My review showed that the filed Operational Benefits of AMI and Smart Grid do not include typical operational benefits from, for example: (1) improved asset utilization efficiency, (2) enhanced service quality which includes outage reduction benefits, and (3) distribution network efficiency. Therefore, it is clear to me that more work in required to properly account for additional Operational Benefits. Without properly accounting for all the operational impacts, the net effect will be for DP&L to overcharge customers for the entire program. This is because operational benefits are clearly netted against the costs customers must pay. The more costs that are allocated to societal benefits, potentially the less netting of costs takes place, thereby increasing the customer's share.

B. Development of an Accountability Plan

Given the multi-year schedule for full implementation of these programs, an accountability plan should be put in place to monitor both costs and benefits for both DP&L and its customers. Appropriate performance measures will ensure that both DP&L and its customers realize the expected benefits for the costs estimated in the filing. This accountability plan should be developed in a collaborative manner. Some elements that should be considered include:

- Establishment of a collaborative working group to oversee the accountability plan;

- Metrics to track the achievement of operational and societal benefits over time, actual spending vs. estimates, deployment progress versus scheduled progress;
- Periodic reporting by DP&L on its deployment progress, issues and their resolutions, other items as requested by the working group; and
- Establishment of a "true-up" mechanism to adjust for differences between actual prudent costs/benefits and those costs/benefits initially assumed. The purpose of this "true-up" is to ensure that both DP&L and its customers are held accountable to the guarantees and commitments made for these programs.

C. Justification of IT Systems Through Operational and Societal Benefits

DP&L has included $95million of IT Systems capital cost and is representing roughly $7.5million of operational benefits from mainframe O&M savings and depreciation savings from early retirement of capital. In rough terms, this represents a 12-year payback period. While there may be Societal Benefits associated with the IT Systems, this is not presented by DP&L. Since enterprise IT Systems rarely go 12 years without major upgrades or changes, I believe the payback period is too long to justify the total IT Systems capital cost under the AMI / Smart Grid program. However, I also believe there are many additional Operational and Societal Benefits associated with these IT Systems that are yet to be captured by DP&L.

D. Alignment of Costs, Associated Benefits, and Beneficiaries

The structure of the filing does not align the costs, benefits and beneficiaries, making it difficult to verify that the allocation of costs are appropriately aligned with the beneficiary(s) that will enjoy the benefit. This information should be provided in a format that provides the necessary understanding to ensure that DP&L and its customers are treated fairly prior to approval to proceed with deployment. Once the information is available it should be presented in a collaborative manner with stakeholders. I envision a simple summary table for each investment, that is, AMI system, each IT system, distribution automation, substation automation, where the capital cost, deployment O&M costs, post-deployment O&M costs, Operational Benefit, and Societal Benefit are shown for each.

E. Justification of a few Specific Costs

DP&L has included some unusually high costs in the project management and engineering of the communications systems projects, the costs of substation automation, and the inclusion of the GIS audit.

- There appears to be layering of project management, that is, utility project management on top of vendor project management, in the communications systems portfolio that accounts for $6.4 million of cost on a $48.9 million systems, hardware, and engineering technical cost. This is twice the project management cost of a typical high technology project. I would expect about $3M for project management on a communications project of this size.

- The total engineering costs of the communications portfolio is $14.7 million on a $40.6 million systems and hardware cost. This is more than twice the engineering cost of a typical high technology project. I would expect about $5 million for engineering on a communications project of this size.
- The substation automation cost per substation is shown as $450 thousand which is twice the typical cost of automating a substation. DP&L plans to roll-out many substations which should have repeatable designs thus greatly reducing engineering costs. This estimate needs to be revised.
- The cost for GIS is $8.8 million of capital in the AMI chapter. It is not for new technology but rather for performing a field audit of DP&L distribution assets to correct deficiencies in the existing GIS database. While it is good to have an accurate GIS at the beginning of the AMI / Smart Grid program, this cost is not specific to AMI and should not be included in the cost for the AMI / Smart Grid program.

In summary, DP&L's proposed AMI / Smart Grid program, has several weaknesses as filed, particularly the accounting of benefits and costs and sourcing parameters.

VII. CONCLUSION

Q19. DOES THIS CONCLUDE YOUR TESTIMONY?

A19. Yes. However, I would like to reserve the right to incorporate new information that may subsequently become available. I also would like to reserve the right to supplement my testimony in the event that DP&L submits new or corrected information in connection with this proceeding.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing the *Direct Testimony of Steven Pullins on Behalf of the Office of the Ohio Consumers' Counsel* has been served via electronic transmission this 26th day of January, 2009.

Jacqueline Lake Roberts,
Assistant Consumers' Counsel

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INT-360. Referring to Book II, Chapter III, pages 17 and 18, identify and describe the specific applications that need to be upgraded to support primary AMI functionality

a. identify and describe the specific applications that use AMI information to support other functions that are not typically AMI specific?

RESPONSE: General Objections Nos. 2, 6, 7. This interrogatory is overly broad, unduly burdensome, and seeks information available in pre-filed testimony, schedules, and/or workpapers filed by DP&L with the Commission in its Application in these proceedings. Without waiving these objections, DP&L states that please see the response to INT-360 b. below

b. Why are the specific applications that use AMI information to support other functions that are not typically AMI specific included in exhibits 3.4.1.a and 3.4.1.b

RESPONSE: General Objections Nos. 2, 6, 7. Without waiving these objections, DP&L states that the following systems will use the AMI information to enhance their operation:

1. Outage Management System will use the AMI information for in service/out of service indication to complement the existing system inputs to determine outages.

2. Distribution Management System and Distribution Planning tools will use the AMI information to enhance the volt/VAR

optimization process and load study analysis process to enhance asset management on the distribution system.

3. *Meter Data Management System* will use the *information* from the AMI network to determine load profiles of customer based on their actual interval energy usage.

4. Customer Information System will be able to indirectly determine the status of a customer's electricity, current reading, voltage, and power quality through and on-demand read while the customer is on the phone.

5. eServices system and outage management systems can send information to customers regarding acknowledgment of outages and expected restoration times or work order status. The AMI information will be presented to the customer through the eServices system to allow the customer to better manage their energy usage.

6. Mobile Workforce Management System can use the AMI information to verify customer operation or issues related to a work order for quality assurance purposes. The mobile workforce management system can use AMI information to automatically

close out work orders related to customer call backs for outages after the suspected problem was repaired.

7. Load Management Systems can use the information from the AMI network and HAN device status to measure the existing load under DR at any point in time as well as calculate the average load each device controls during the peak time. This can lead to a much more accurate estimate of load under DR and actual load shed during an DR event.

WITNESS RESPONSIBLE: Jeff Teuscher

INT-362. Referring to Book II, Chapter III, page 20, and the last paragraph, how will two way power flow (e.g. customer owned distributed generation, plug in hybrid operating in vehicle-to-grid mode, etc) be supported in the future?

RESPONSE: General Objections Nos. 2, 6, 7. This interrogatory is overly broad, unduly burdensome, and seeks information available in pre-filed testimony, schedules, and/or workpapers filed by DP&L with the Commission in its Application in these proceedings. Without waiving these objections, DP&L states that the AMI system will be able to track power flows in both directions and communicate the information to the Company information systems for analysis.

WITNESS RESPONSIBLE: Jeff Teuscher

INT-368. Referring to Book II, Chapter III, page 24,what improvement in reliability metrics (SAIDI, SAIFI) are expected as a result of the integration of AMI with OMS?

RESPONSE: General Objections Nos. 2, 6, 7. This interrogatory is overly broad, unduly burdensome, and seeks information available in pre-filed testimony, schedules, and/or workpapers filed by DP&L with the Commission in its Application in these proceedings. Without waiving these objections, DP&L states that with the deployment of AMI and OMS, DP&L will have to baseline the reliability standards due to the fact they will have more accurate outage data from the smart meters. DP&L did not perform a study on how these indices will be affected with the deployment of these two systems. Please refer to the answer on INT - 402 for how CAIDI will be affected with the CCEM plan.

WITNESS RESPONSIBLE: Jeff Teuscher

INT-369. Referring to Book II, Chapter III, page 24, will MWMS be integrated with OMS and AMI to reduce time to dispatch trouble crews and reduce outage durations?

RESPONSE: General Objections Nos. 2, 6, 7. This interrogatory is overly broad, unduly burdensome, and seeks information available in pre-filed testimony, schedules, and/or workpapers filed by DP&L with the Commission in its Application in these proceedings. Without waiving these objections, DP&L states yes.

WITNESS RESPONSIBLE: Karen Garrison