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EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	)	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

VOLUME 3

ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: January 27, 2011

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DIRECT TESTIMONY OF
THOMAS L. KIRKPATRICK
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: January 27, 2011

INDEX TO DIRECT TESTIMONY OF
THOMAS L. KIRKPATRICK

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
THOMAS L. KIRKPATRICK
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

PERSONAL DATA

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Thomas L. Kirkpatrick. My business address is 850 Tech Center Drive, Gahanna, OH 43230.

Q. BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Vice President of Distribution Operations for Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo), collectively known as AEP Ohio (AEP Ohio or the Companies). AEPSC is a subsidiary of the American Electric Power Company, Inc. (AEP) and provides technical and other services to AEP Ohio and other operating units within the AEP System.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I hold a Bachelor's Degree in Electrical Engineering from Gannon University with a focus on power systems. I am also a member of the Institute of Electrical and Electronics Engineers, a registered Professional Engineer in the State of Ohio, and have completed AEP's Management Development Program at The Ohio State University.

I began my career with AEP in 1980, where for more than 25 years, I held progressively responsible positions in a broad range of functional areas including vice president – Distribution Operations, vice president – Distribution Asset Management, and Distribution project lead in support of the merger of AEP and Central and Southwest Corporation. I have also worked outside of AEP at Patrick Engineering, Inc. as Vice President – Energy Practice and at Davies Consulting, Inc. as Senior Vice President – Energy Practice. I was named to my current position in September 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF DISTRIBUTION OPERATIONS FOR AEP OHIO?

A. I am responsible for overseeing the planning, construction, operation and maintenance of the distribution system. My duties include extension of service to new customers, the safe and reliable delivery of service to our customers and restoration of service when outages occur. My responsibilities also include all meter service related activities, including meter reading and the oversight of AEP Ohio's distribution system vegetation management program, asset management programs, reliability programs and major capacity programs.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain how AEP Ohio maintains the present distribution system, including the current vegetation management program. I propose that the Commission continue their support of the ongoing Enhanced Service Reliability Plan. I describe the current state of the AEP Ohio distribution system and the need for ongoing capital investment. Next, I will discuss some examples of the types of investments a Distribution Investment Rider (DIR) would provide, which will include the ongoing investment in the gridSMART® Program. Finally, I discuss the volatility associated with major storms in Ohio and the need to establish a Storm Damage Recovery Mechanism.

CURRENT DISTRIBUTION RELIABILITY PROGRAMS

Q. PLEASE BRIEFLY DESCRIBE AEP OHIO'S SERVICE TERRITORY.

A. AEP's distribution system in Ohio includes approximately 1,500 distribution circuits and approximately 32,000 miles of primary overhead distribution lines and approximately 6,500 miles of primary underground distribution lines operated at voltages from 4.16kV to 34.5kV. Residential and most commercial customers are served at secondary voltages via approximately 470,000 overhead and underground distribution transformers. AEP also operates and maintains approximately 520 distribution substations.

Q. HOW DOES AEP OHIO MAINTAIN AND IMPROVE RELIABILITY ON ITS DISTRIBUTION SYSTEM?

A. AEP Ohio uses various combinations of programs to maintain and improve its distribution infrastructure. These programs are designed to minimize the impact of service interruptions to customers and can be divided into four major categories:

- Distribution Asset Management Programs;
- Distribution Capacity Additions;
- Distribution Vegetation Management Program; and
- gridSMART® Program.

Q. PLEASE BRIEFLY DESCRIBE AEP OHIO'S DISTRIBUTION ASSET MANAGEMENT PROGRAMS.

A. The distribution asset management programs are designed to optimize expenditures and system performance. AEP Ohio executes a variety of ongoing Distribution Asset Management Programs. For example, some of these programs and their roles with respect to distribution system reliability are as follows:

- *Overhead Circuit Facilities Inspection and Maintenance Program:* Under this asset program, AEP Ohio visually inspects its overhead facilities to identify and correct conductor, hardware and equipment deficiencies and other potential problems before they cause service interruptions.

- *Pole Inspection and Maintenance Program:* The objective of this asset program is to maintain and prolong the structural integrity of AEP Ohio's wood poles. In order to maintain and extend where possible the useful life of these assets, AEP Ohio conducts a pole inspection and maintenance program designed to inspect, treat, reinforce and/or replace wood poles on a continual basis.

- *Pad-Mount Equipment Program:* The objective of this program is to visually inspect and perform any corrections required on the external, above-ground portions of underground distribution facilities (pad-mount transformers, pedestals, switchgear, etc.) on an ongoing basis.

- *Recloser Maintenance / Replacement Program:* The objective of this program is to inspect and test in-service recloser units for reliable operation and to maintain or replace, as needed, those units that are not operating properly or require maintenance.

- *Line Capacitor Program: A*EP Ohio has distribution line capacitor banks in service within the Company's service territory. AEP Ohio conducts an annual check of capacitor banks in service to ensure reliable and accurate operations.

- *Network System Program:* The objective of this program is to ensure reliable service to our network system customers through preventive maintenance, inspections and reactive maintenance of our urban underground networks and through capital replacement of equipment as necessary.

- *Underground Cable Program:* The objective of this program is to address underground cable deficiencies by restoring the integrity of the cable through either cable injection or cable replacement. This initiative targets high capacity underground cables in our distribution substations and circuits as well as underground residential cables such as those that serve residential subdivisions, thereby minimizing the likelihood of future service interruptions to our customers.

- *Cutout and Surge Arrestor Program:* This program targets replacement of known deficiencies present in selected aged, cutouts and surge arrestors on the distribution system.

Q. WHAT IS THE PURPOSE AND NEED OF THE SECOND PROGRAM CATEGORY OF DISTRIBUTION CAPACITY ADDITIONS?

A. Capacity additions represent new capital invested to meet the needs of growth due to expansion and increased load. AEP Ohio routinely completes capital investments to serve new load and prevent overloading of existing equipment.

Q. PLEASE DESCRIBE AEP OHIO'S THIRD MAJOR CATEGORY OF PROGRAMS, THE DISTRIBUTION VEGETATION MANAGEMENT PROGRAM.

A. AEP Ohio has approximately 32,000 miles of primary voltage overhead distribution lines that require varying levels of vegetation management. The Company's vegetation management program is a comprehensive, integrated program that employs a variety of practices such as mechanized trimming including aerial sawing; manual trimming including roping and hand climbing; brush mowing; and herbicide applications. These practices are conducted in accordance with standards established by the American National Standards Institute (ANSI), the Occupational Safety and Health Administration (OSHA), the International Society of Arboriculture (ISA) and the National Electrical Safety Code (NESC), as they relate to, among other things, the pruning and removal of trees (arboriculture), safety and worker protection, work clearances and training requirements, and safety clearance guidelines.

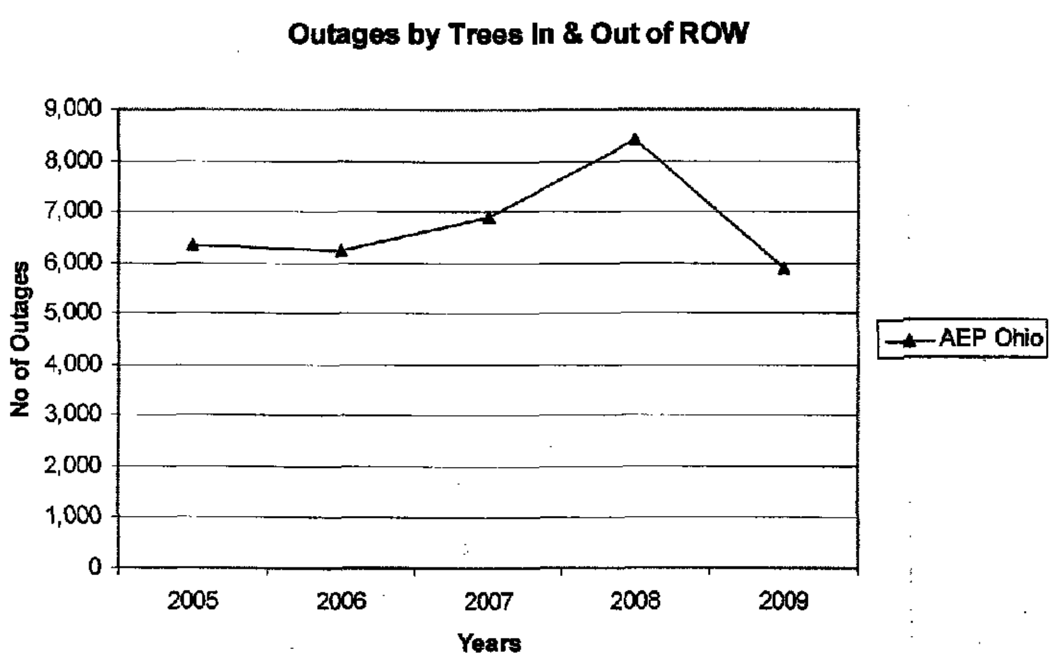
Previously, AEP Ohio's vegetation management program was a mix between a performance-based approach, which prioritized work on AEP Ohio's facilities after taking into consideration a number of input variables, and a cycle-based approach, which maintains every distribution circuit on a four-year cycle. Since the Commission approved movement to a cycle-based approach for AEP Ohio's distribution system in Case No. 08-917-EL-UNC and Case No. 08-918-EL-UNC, AEP Ohio has been migrating from a performance-based approach to a cycle-based approach under the Enhanced Service Reliability Rider (ESRR). Converting to a cycle-based approach, as previously approved by the Commission, was based on a five-year implementation program to convert all distribution circuits to a cycle-based four-year maintenance cycle. The ESP provided additional funding over base levels for the first three years of the five year transition to the cycle-based program.

The cycle-based approach has been shown to be more effective in reducing the frequency and duration of circuit outages, as was previously discussed in Case No. 08-917-EL-UNC and Case No. 08-918-EL-UNC.

Q. HAS AEP OHIO EXPERIENCED ANY BENEFITS BY INCREASING ITS SPENDING ON VEGETATION MANAGEMENT?

A. Yes. Increased spending since initiation of the ESRR in the 2008-2009 time period has led to reductions in tree-caused outages, resulting in improved reliability to the customer. Referring to Chart 1, AEP Ohio was experiencing a gradual increase in the number of tree related circuit outages[1] from 2005 – 2008. After initiation of the ESRR, there was a sharp decline in the number of outages caused by trees located in and out of the rights-of-way.

Chart 1



[1] Based on IEEE-1366 definitions for Major Storms.

In order to continually manage vegetation growth on the distribution system, AEP Ohio proposes to complete the Commission-approved Enhanced Service Reliability Plan, designed to move from a performance-based program to a four year cycle-based trimming program for all of the Company's distribution circuits. The Enhanced Vegetation Program will capture continued improvement in reliability due to reduced tree related interruptions.

Q. IS AEP OHIO REQUESTING THE ENHANCED SERVICE RELIABILITY PLAN BE CONTINUED IN THIS ESP FILING?

A. Yes. The Enhanced Service Reliability Plan as originally proposed by AEP Ohio and subsequently approved by the Commission was designed to be implemented over a five-year period. The previous ESP approved funding for the 2009-2011 period. Funding for the completion of the five-year implementation period (2012-2013), as shown in Chart 2, is required to complete the conversion from a performance-based approach to a cycle-based approach.

Chart 2

AEP Ohio - Enhanced Service Reliability Plan							
	Case No. s 08-917 & 08-918			**Case No. s** 11-346 & 11-348			
Period	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**Total**
O&M	$26M	$28M	$30M	$31M	$31M	TBD	$146M
Capital	$5 M	$7M	$8M	$6M	$5M	$0	$31M

The dollars in Chart 2 are incremental funding above the base. The O&M base, as established in Case No.s 08-917-EL-SSO and 08-918-EL-SSO, is approximately $24 million and the base capital is approximately $2.5 million on an annual basis.

Q. ONCE THE FIVE-YEAR IMPLEMENTATION PERIOD IS COMPLETE, WILL ADDITIONAL FUNDS ABOVE CURRENT BASE SPENDING LEVELS BE REQUIRED TO MAINTAIN THE CYCLE-BASED VEGETATION MANAGEMENT PROGRAM?

A. Even though the conversion to a four year cycle-based vegetation management program is expected to be completed at the end of 2013, an incremental amount above the current base level of O&M will be required to maintain the program going forward. This will be addressed in future regulatory filings.

Q. FINALLY, PLEASE DESCRIBE THE PROGRESS OF THE FOURTH CATEGORY, WHICH IS THE gridSMART® PROGRAM.

A. Company witness Sloneker describes the details of gridSMART® – Phase 1, which was designed to explore the gridSMART® technologies, develop the communication interfaces, and fine tune the details of the processes for operating the gridSMART® system. Going forward, it is the intent of AEP Ohio to expand elements of a gridSMART® program throughout the AEP Ohio service territory as part of normal business through the DIR. The vision is to have a gridSMART® program deployed system wide over a ten-year period.

It is also expected that the full implementation of gridSMART® will require the early retirement of the current meters. Because of the expected volume of meters to be displaced by smart meters, it is proposed that the remaining net book value (NBV) of the retired meters be set up as a regulatory asset and recovered in a future filing. In the current gridSMART® - Phase 1 program, the volume of retired meters is relatively small, and the lost value of the retired meters is recovered in the over/under accounting process approved for the non-FAC riders in the 2009 – 2011 ESP. Company witness Mitchell discusses the accounting proposal in more detail.

PROPOSED DIR

Q. PLEASE EXPLAIN THE PURPOSE OF THE AEP OHIO DIR.

A. The purpose of the AEP Ohio DIR is to provide capital funding for distribution assets detailed in the FERC Chart of Accounts, including, but not limited to:

- Support the distribution asset management programs described in this testimony;
- Provide for distribution capacity and infrastructure additions driven by customer demand; and
- Support the continued implementation of advanced technology and a gridSMART® program.

Q. WHY IS ADDITIONAL CAPITAL INVESTMENT REQUIRED TO SUPPORT DISTRIBUTION INVESTMENT?

A. The failure of aging infrastructure continues to be the primary cause of customer outages and reliability issues. This funding would allow AEP Ohio to move from a reactive response for equipment failures to a more proactive replacement strategy that identifies, replaces and/or refurbishes assets with a high likelihood of failure. Additionally, certain components of the aging distribution infrastructure do not support the advanced technologies of gridSMART®. Expansion of gridSMART® can be utilized to reduce customer outage duration and provide customers the tools to actively participate in energy management and lower utility costs.

Company witness Hamrock explains the need for a limited amount of ongoing capital investment and the need to reduce regulatory lag associated with this capital investment through the DIR. As I explained above, the need for capital investment on a system as large as that of AEP Ohio is continuous as assets reach the end of their expected lives. The DIR would provide a method to fund costs associated with needed investment on an ongoing basis, enable the continued investment in the distribution system, and minimize the regulatory lag associated with the traditional recovery methods.

Q. WILL ADDITIONAL O&M BE NEEDED TO SUPPORT INCREMENTAL CAPITAL INVESTMENT IN A DIR?

A. Yes. Any incremental capital investment will require additional O&M to implement and maintain the incremental capital. First, new capital investment requires O&M funds to support the physical installation of the new equipment. For instance, installation of a new transformer may first require an inspection of the transformer to determine the condition of the transformer and the surrounding infrastructure. This inspection requires O&M funds to complete. Second, new capital investment requires incremental O&M to support the ongoing maintenance of the new equipment installation. For example, the addition of a new distribution substation requires additional O&M funding to operate and maintain the equipment contained within the new substation.

Q. HOW IS IT PROPOSED THAT THIS INCREMENTAL O&M WILL BE FUNDED?

A. It is proposed that the Carrying Charge Rate for the capital investment be adjusted to include the needed O&M. This proposal will ensure that there is sufficient O&M to support new capital investment. Historically, AEP Ohio's O&M costs are approximately 7% of average net capital investment. This would indicate that O&M needs for incremental net capital are 7%. As it could be argued that new capital assets would need somewhat less O&M funds in the early years of installation than the average aged asset, AEP Ohio proposes that this incremental O&M be funded at a rate of 3.5% of net capital investment. Company witness Moore incorporates this O&M adjustment factor into her discussion of the Carrying Charge Rate in her testimony.

Q. HOW WILL AEP OHIO CHOOSE ASSETS FOR DISTRIBUTION INVESTMENT?

A. AEP Ohio will perform analyses of historical performance of AEP Ohio assets over time to predict future asset performance. This type of analysis will provide an indication of expected asset performance in the future so that targeted investment strategies can be developed proactively. While life cycle analysis provides guidance on when the probability for failure may occur, AEP Ohio will also use field diagnostics to determine whether specific assets should remain in service past their predicted life. These inspection programs include pole inspections, underground cable diagnostics, and detection of deterioration through Infra-red (IR) testing and measurement of electro-magnetic interference (EMI). Charts 3 and 4 below illustrate failure rates of distribution pole and transformer assets as they age.

Chart 3

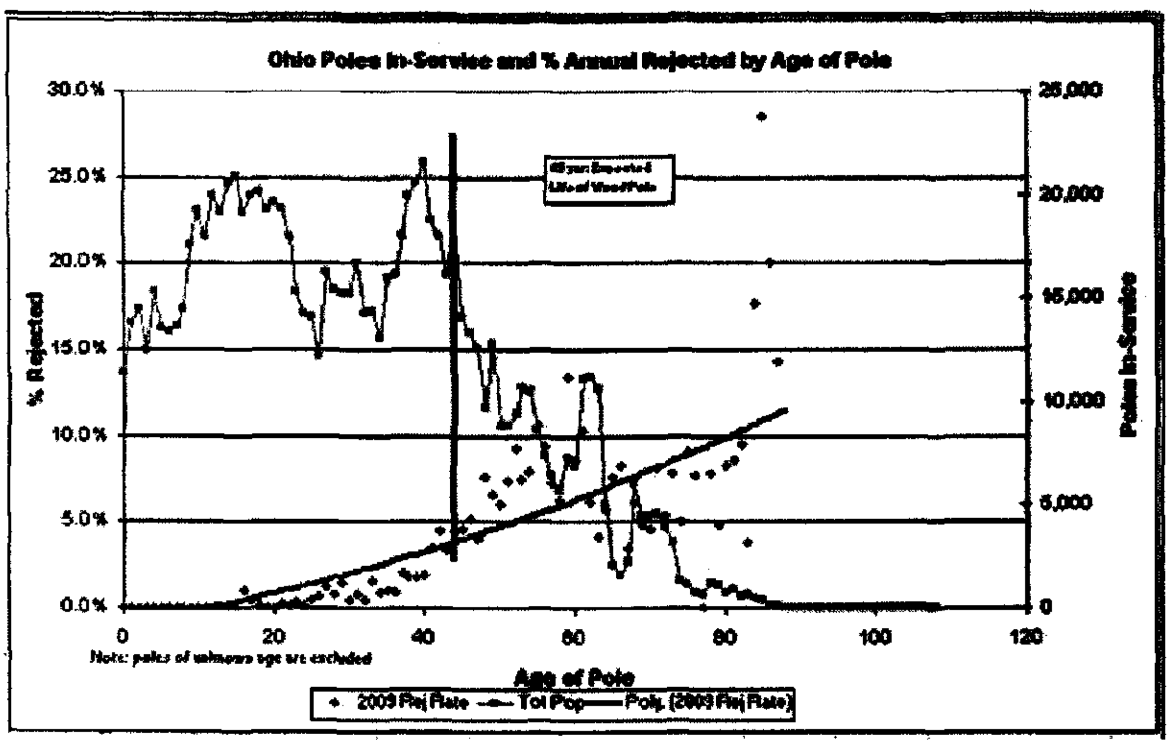
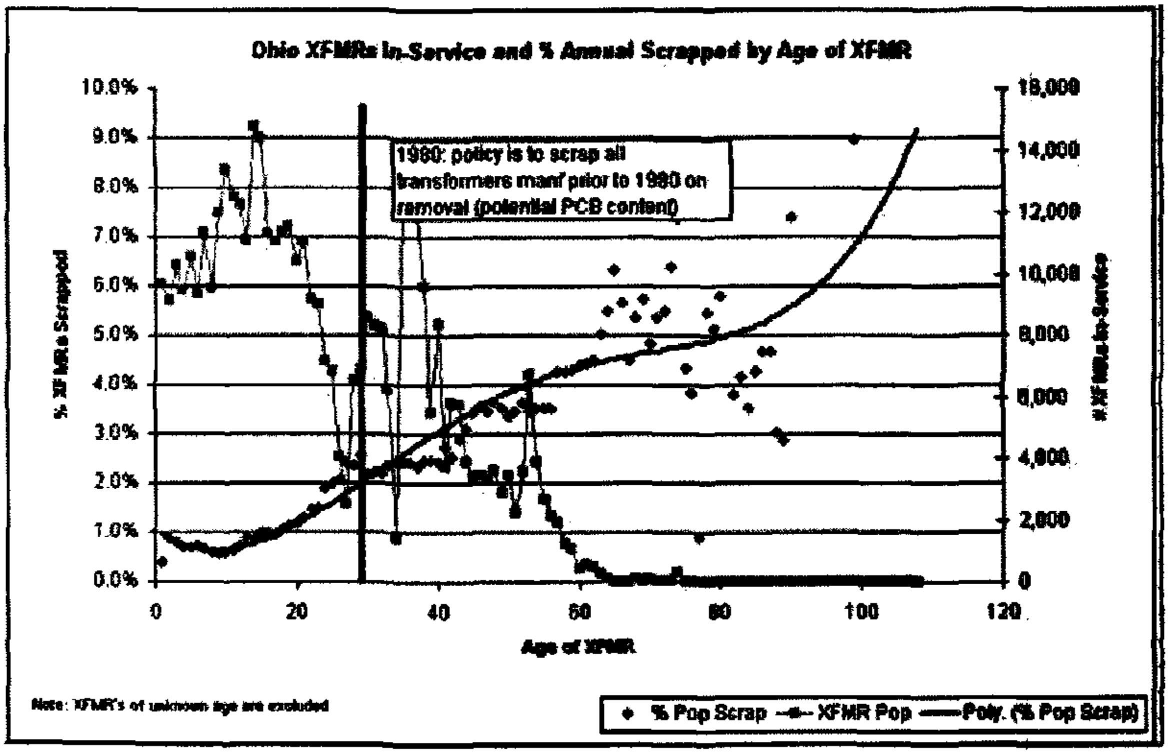


Chart 4



Life cycle analysis, such as this, provides impetus to look more deeply at these assets to determine whether proactive replacement programs are in order. While this provides guidance on when the probability for failure may occur, AEP Ohio will also use field diagnostics as discussed above to determine whether specific assets should remain in service past their predicted life. In addition, AEP will identify the impact of the performance of different types of assets utilized in the distribution system to target asset investment that will impact the largest number of customers.

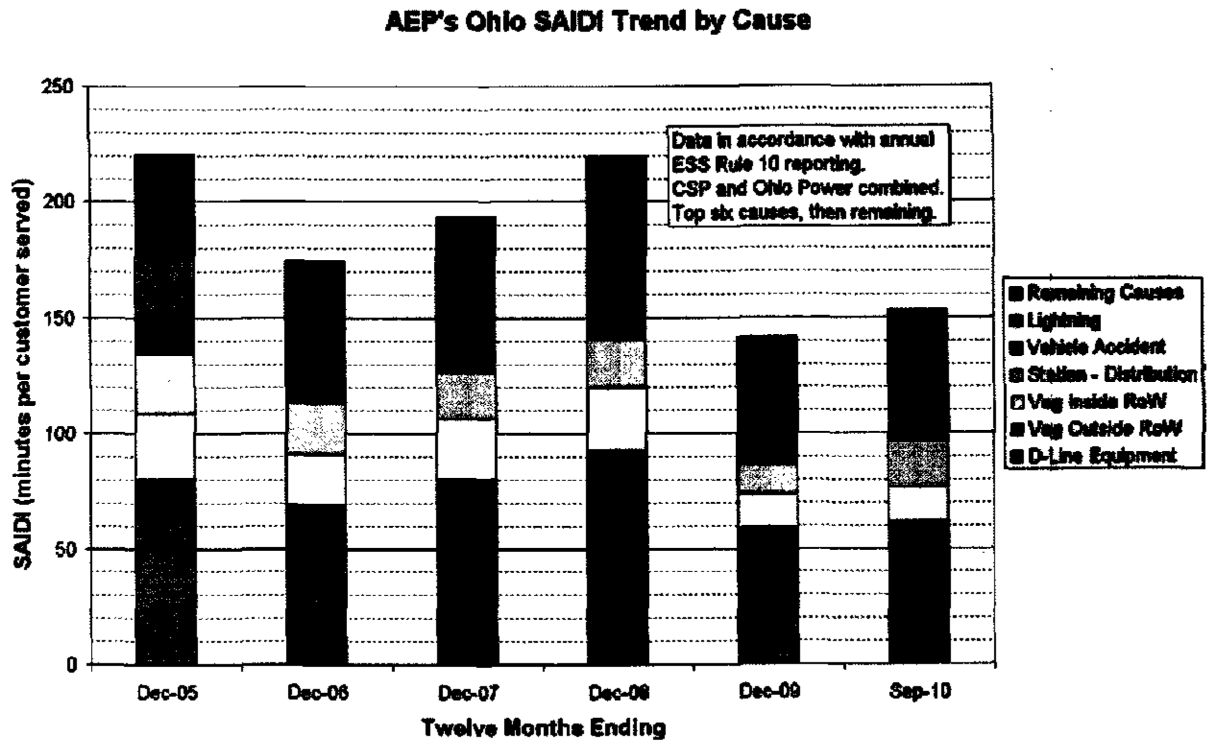
Q. CAN YOU GIVE AN EXAMPLE OF AN ASSET THAT WOULD PROVIDE SIGNIFICANT BENEFIT TO THE CUSTOMER IF IT WAS INCLUDED IN THE DIR?

A. Yes. Distribution substation circuit breakers that control the flow of electricity to each of the AEP distribution circuits are critical assets. Failures of these devices could result in long duration outages for entire feeders and in many cases may extend outages unnecessarily to other components of the substation. For example, there are 395 distribution circuit breakers in AEP Ohio over 40 years old. Many of these circuit breakers no longer have spare parts to facilitate maintenance and repair. By proactively replacing the assets prior to forecasted failure instead of waiting for these assets to fail, overall reliability of this asset type would improve as failures and subsequent customer interruptions can be avoided before they happen.

Q. WHAT IS THE CURRENT STATE OF THE ASSETS ON THE AEP OHIO DISTRIBUTION SYSTEM?

A. The AEP Ohio distribution system is comprised of assets ranging from new to equipment installed more than fifty years ago. Distribution substation and distribution line assets comprise the second highest cause of failure on the distribution system after tree related outages as seen in Chart 5 below.

Chart 5



Continuance of the ESSR will help address tree related outages. Additional investment in the distribution assets is needed to positively impact the equipment failure related causes of customer outages.

Q. WHY DOES AEP OHIO NEED A RIDER FOR DISTRIBUTION INVESTMENT VERSUS ONGOING REPLACEMENT THROUGH NORMAL PROCESSES?

A. The asset management and reinvestment programs described earlier are designed to address aging and deteriorating infrastructure, however are not funded at the level needed to sustain or improve the failure trends. As illustrated in Charts 3 and 4 failure rates will continue to rise as assets age, outpacing AEP Ohio's ability to keep up with replacements with current funding levels. In addition, customer survey results for 2009 show that 16% of residential respondents and 19% of commercial respondents believe their future reliability expectations would increase over the next five years. This translates to over 200,000 residential and 32,000 commercial AEP Ohio customers likely to have higher reliability expectations in the coming years. Significant investment for infrastructure is needed to fund reliability programs and technology upgrades to address this increasing failure profile. Funding this investment as a rider reduces regulatory lag. Company witness Hamrock discusses the benefits of this rider mechanism and the impact of reducing the regulatory lag associated with this type of capital investment.

OTHER INITIATIVES

Q. PLEASE DESCRIBE AEP OHIO'S REQUEST OF MAJOR EVENT DAMAGE RESTORATION O&M EXPENSE.

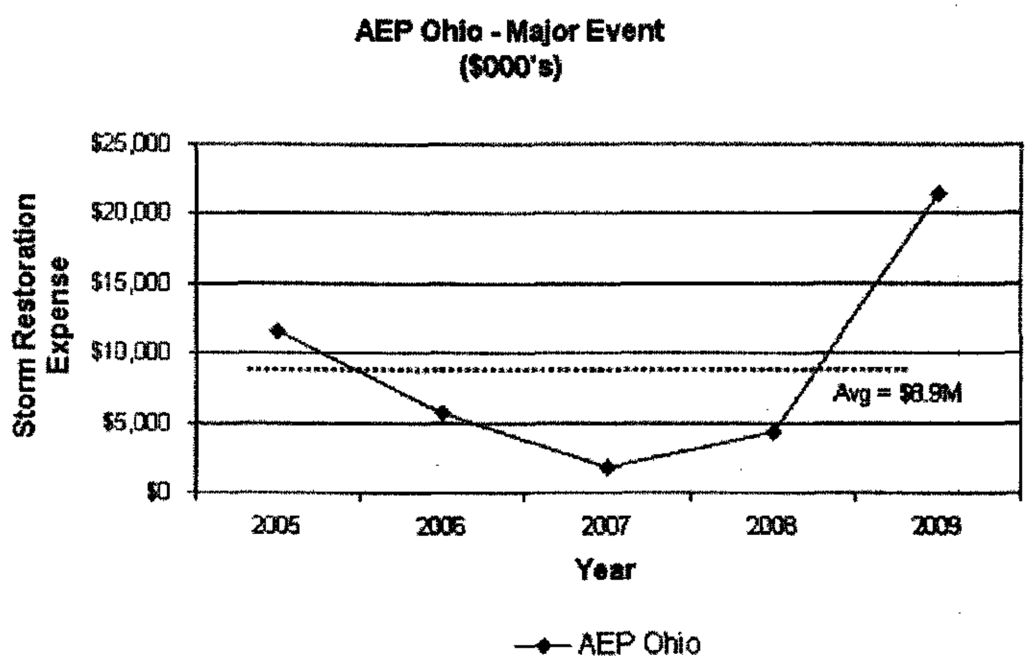
A. Major events are classified as a period of time when the electric delivery system is faced with challenges beyond its normal design criteria. Major storms are determined based on the methodology outlined in IEEE Standard 1366 - 2003, IEEE Guide for Electric Power Distribution Reliability Indices, as adopted by the Ohio Commission in the standards established in O.A.C 4901:1-10-10(B).

Q. WHY IS AEP OHIO PROPOSING A STORM DAMAGE RECOVERY MECHANISM?

A. Given the volatility of major storms and major storm damage restoration O&M expenses from year to year, AEP Ohio is proposing that a Storm Damage Recovery

Mechanism be created in the amount of $8.9 Million. See Chart 6 for the five-year historic expenses for major storms by year, excluding expenses associated with Hurricane Ike restoration activities. This mechanism is necessary to preserve forecasted O&M for planned maintenance activities. If funds are constantly diverted to cover the expense of major storms, it disrupts the completion of planned maintenance and ultimately has an impact on the reliability of the system. This mechanism is further discussed by Company witnesses Moore and Mitchell.

Chart 6



Note: Costs exclude Hurricane Ike.

Q. WOULD THE STORM DAMAGE RECOVERY MECHANISM INCLUDE CAPITAL COSTS INCURRED AS A RESULT OF A MAJOR STORM?

A. No. Capital costs would become a component of the DIR or would be included in rate base in the next distribution rate case.

SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my testimony, I discussed how AEP Ohio maintains the present distribution system, including vegetation management. I then proposed the continuation of the current ESSR to complete the Commission approved transition of the vegetation management program to a four-year cycle-based program. I then described the DIR and how it would provide a mechanism to continue to invest in a reliable distribution system. Finally, I discussed the volatility associated with major storms in Ohio and the need to establish a Storm Damage Recovery Mechanism.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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DIRECT TESTIMONY OF
KAREN L. SLONEKER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: January 27, 2011

INDEX TO DIRECT TESTIMONY OF
KAREN L. SLONEKER

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
KAREN L. SLONEKER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

PERSONAL DATA

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Karen L. Sloneker. My business address is 850 Tech Center Drive, Gahanna, OH 43230.

Q. BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Director of Customer Services and Marketing for Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo), collectively known as AEP Ohio or the Company. AEPSC is a subsidiary of the American Electric Power Company Inc. (AEP) and provides technical and other services to AEP Ohio and other operating units within the AEP System.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I earned a bachelor's degree in Electrical Engineering from The Ohio State University and completed AEP's Management Development Program as well. In addition, I completed professional development programs in Customer Relationship Management and Systems Thinking, and the Fundamentals of Accounting and Finance from The Ohio State University Fisher College of Business.

I have 28 years of electric utility experience and have held various positions in the areas of engineering, information technology, customer service and marketing. I began my career in 1982 as a Performance Engineer at CSP's Conesville Generating Station in Conesville, OH. In 1985, I became a Power Engineer for CSP in Columbus serving as a liaison between CSP and its large commercial and industrial customers.

Three years later, I was promoted to Energy Services Supervisor for the Columbus Division. In 1990, I joined AEPSC as Marketing and Customer Services Training Manager. I returned to CSP in 1993 when I was named Marketing and Customer Service General Office Manager. I was promoted to Ohio Key Accounts Manager/Commercial and Industrial Segment Manager in 1995. I joined the AEPSC IT organization in 1998 as IT Account Manager and was named Application Delivery Managing Director in 2003. In 2004, I was named to my current position as Customer Services and Marketing Director for AEP Ohio.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF CUSTOMER SERVICES AND MARKETING?

A. I am responsible for customer account management and energy efficiency and peak demand reduction in AEP Ohio's service territory, and I am the project director for AEP Ohio's gridSMART® Demonstration Project. I am responsible for the overall design, development, implementation, analysis, and administration of AEP Ohio's field customer services activities. I am also responsible for the resolution of customer inquires such as power quality, quality of service, and billing.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend the continuation of the Energy Efficiency/Peak Demand Response (EE/PDR) Rider and to continue working with a collaborative group to help AEP Ohio develop energy efficiency and demand response programs suitable for our customers. I also discuss and support the implementation of a new Plug-In Electric Vehicle (PEV) Tariff to position AEP Ohio for the broader use of electric vehicles. In addition, I discuss and support the continued implementation of AEP Ohio gridSMART® initiatives in CSP's service territory through the continuation of the Phase 1 gridSMART® rider.

<u>ENERGY EFFICIENCY/PEAK DEMAND RESPONSE (EE/PDR)</u>

Q. PLEASE DESCRIBE THE MANDATES DEFINED BY S.B. 221.

A. Beginning in 2009, AEP Ohio was required to implement energy efficiency programs that achieve specific annual energy savings by the end of 2025 and peak demand reduction programs designed to achieve specified peak demand reductions by 2018. According to S.B. 221, AEP Ohio was required to implement energy efficiency programs that achieve energy savings in 2009 of at least 0.3 percent of the total, annual average, and normalized kWh sales during the preceding three calendar years. This requirement increases 0.5 percent in 2010, 0.7 percent in 2011, 0.8 percent in 2012, 0.9 percent in 2013, 1 percent per year from 2014 to 2018, and 2 percent per year thereafter so as to achieve a cumulative energy savings of 22.2 percent by the end of 2025.

In addition, AEP Ohio must implement programs designed to reduce peak demand by 1 percent in 2009 and increase that reduction by an additional 0.75

percent each year through 2018 to achieve a cumulative total reduction of 7.75 percent through 2018.

Q. WHAT OVERALL BENEFITS IS AEP OHIO ACHIEVING WITH THE EE/PDR PROGRAMS?

A. AEP Ohio is achieving several benefits through its proposed EE/PDR strategy. These benefits include:

- Energy savings to meet S.B. 221 benchmarks.
- Reduction in peak electric demand to meet S.B. 221 benchmarks.
- Changes in customers' behaviors, attitudes, awareness and knowledge about energy use, energy savings and energy efficient technologies.

Q. HOW HAS AEP OHIO IMPLEMENTED EE/PDR REDUCTION REQUIREMENTS TO DATE?

A. In Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, the Company proposed that a collaborative process be used to identify and implement the specific EE/PDR programs proposed. In the Opinion and Order issued by the Commission in March of 2009, the Commission established the EE/PDR riders and confirmed the Company should proceed with the development of EE/PDR programs as justified by the market potential study and include the input of a collaborative of stakeholders.

Q. PLEASE DESCRIBE THE COLLABORATIVE PROCESS AND AEP OHIO'S PARTICIPATION?

A. In November 2009, AEP Ohio filed its 2009-2011 Portfolio Plan and Stipulation (Case No.s 09-1089-EL-POR and 09-1090-EL-POR), which was a compromise of interested parties to implement a portfolio of projects to meet or exceed EE/PDR targets over the 2009-2011 timeframe. The Signatory Parties recommended that the Commission approve the Stipulation and the Commission issued its Opinion and Order in accordance with the recommendations made in the Stipulation. AEP Ohio participated with the interested parties to develop programs that would benefit customers and be in the public's interest. In 2011, AEP Ohio will file its 2012-2014 Portfolio Plan of EE/PDR programs, inclusive of input from a collaborative group of stakeholders, for authorization and recovery through the existing EE/PDR mechanism.

Q. WHAT PROGRESS HAS BEEN MADE IN THE IMPLEMENTATION OF THE EE/PDR PROGRAMS IN THE PREVIOUSLY APPROVED ESP?

A. The Company's most recent EE/PDR update filing in March 2010, Case No. s 10-318-EL-EEC and 10-321-EL-EEC provides the details of the EE/PDR programs and the progress of the implementation. The Company achieved the S.B. 221 benchmark targets in 2009.

Q. IS AEP OHIO REQUESTING TO CONTINUE THE EE/PDR RIDER IN THIS ESP?

A. Yes. AEP Ohio is requesting the Commission approve the continuation of the EE/PDR Rider mechanism established in the 2009 ESP and subsequently updated in Case No.s 10-318-EL-EEC and 10-321-EL-EEC. For additional details on the rider regulatory mechanism, please see Company witness Moore.

<u>**PLUG-IN ELECTRIC VEHICLES (PEV)**</u>

Q. WHAT IS BEING PROPOSED BY AEP OHIO IN THE PEV TARIFF?

A. AEP Ohio is proposing an experimental PEV Tariff that will include a time-of-use (TOU) rate that will encourage AEP Ohio customers to charge Plug-in Electric Vehicles during off-peak hours at a discounted electricity rate. It is proposed that this tariff will be offered initially to approximately 200 customers across the AEP Ohio territory. To facilitate the implementation of this tariff, AEP Ohio is proposing, at its discretion, to install an additional TOU meter that would be dedicated to the PEV charging station. The customer agreement would provide for reimbursement of up to $2,500 to install a certified charging station and TOU meter on the customer's premises through a licensed contractor. To qualify for the tariff and reimbursement, the PEV must be registered and operable on public highways in the state of Ohio. This setup will allow AEP Ohio to implement the tariff and collect the necessary test data to determine if all AEP Ohio customers can benefit from a PEV Tariff.

Q. WHY IS THE PEV TARIFF NEEDED AND WHAT ARE THE BENEFITS?

A. It is anticipated that automobile manufacturers will begin offering PEVs en masse beginning in 2011. According to Michael Liebreich, chief executive of Bloomberg New Energy Finance, "2011 will see the launch of a large number of new plug-in hybrid and electric vehicle models around the world."[1] From an energy perspective, PEVs that use electricity are more environmentally friendly than traditional vehicles that use gasoline, and will reduce overall CO2 emission levels. PEVs are expected to reduce the nation's dependency on foreign oil, but PEVs will also have the potential to place a substantial burden on the nation's distribution grids and require

[1] Bloomberg New Energy Finance, Daily News Briefs, Nov 01, 2010, http://www.bnef.com

new infrastructure to meet the growth in electric demand for charging PEVs. The need for new infrastructure investment may be minimized by implementing programs, such as a PEV tariff that will incent customers to charge PEVs during off-peak hours, and customers will enjoy lower electric rates with the special PEV tariff if they utilize off-peak charging.

Q. HOW WILL THE PEV TARIFF BE IMPLEMENTED?

A. The mechanics of implementing the tariff and cost recovery are provided by Company witnesses Moore and Mitchell.

<u>gridSMART® – PHASE 1</u>

Q. WHAT HAS AEP OHIO ACHIEVED TO DATE THROUGH THE IMPLEMENTATION OF gridSMART® - PHASE 1?

A. Phase 1 has enabled AEP Ohio to gain data and experience to subsequently implement future installations throughout the rest of our Ohio service territory and address any unforeseen problems associated by deploying these technologies to a diverse customer base on a smaller scale. The Company believes that the experience gained during Phase 1 installations has prepared us for a more efficient and effective implementation to our broader customer base and service territory throughout Ohio.

In addition, AEP Ohio customers in the Phase 1 are expected to receive the following benefits:

1. Better information concerning their electricity usage, both on a near real-time and historical basis;
2. Greater control over their energy usage decisions allowing them to conserve energy, save money and help to protect the environment;

3. Improved meter reading accuracy; and
4. Fewer outages and shorter outage durations.

Through complete implementation of the Phase 1 goal, AEP Ohio expects to achieve:

1. Improved safety for our employees, reduced outage events and duration;
2. Real-time information for system operation purposes;
3. Enhanced system operation and outage restoration; and
4. Demand reduction through new tariff offerings and the education of customers regarding energy costs and technology benefits.

Q. CAN YOU OUTLINE THE gridSMART® – PHASE 1 PROGRAM COST?

A. In a previously filed case, Case No.s 08-917-EL-SSO and 08-918-EL-SSO, the Company estimated the cost of the gridSMART® – Phase 1 to be approximately $109 million. AEP Ohio's gridSMART® - Phase 1 originally included 110,000 smart meters and the associated communication system, 70 distribution automation circuits and 17 integrated volt-var control circuits, cyber security and interoperability, consumer education and up to 10,000 home area networks for customers on time differentiated rates. In the final order of this case, the Commission directed the Company to seek matching funds from the Department of Energy (DOE). In order to successfully compete for American Reinvestment Recovery Act (ARRA) Smart Grid Demonstration Project funding, AEP Ohio proposed additional initiatives under the guidance provided by the DOE that exceeded those included in the earlier ESP filing. AEP Ohio's gridSMART®

Demonstration Project was expanded to include a real-time pricing pilot with up to 1,000 Home Energy Management devices, a demand dispatch engine, 10 PEVs with smart chargers and 2 MW (80 units) of Community Energy Storage. Also included in the Demonstration Project is the increased data collection and reporting that will be required for the DOE beyond the data collection and reporting that was planned to meet Ohio Commission requirements. DOE Stimulus Funds cover half of the \$150.3M project costs with the remaining investment for the original scope of work being approximately \$54.5M, additional AEP work committed for the expanded scope of work being approximately \$9.8M and in-kind contributions of approximately \$11M from our partners on the project.

Chart 1 provides a summary of the Forecast Expenses, Actuals To-Date, and Future Expenses for the gridSMART® Demonstration Project including the matching dollars committed from the DOE and in-kind contributions.

Chart 1

AEP Ohio – gridSMART® Demonstration Project			
gridSMART®	**Forecast Expenses**	**Actuals To-Date**	**Future Expenses**
AEP OH	\$64M	\$51M	\$13M
In-Kind Contributions	\$11M	\$0M	\$11M
DOE	\$75M	\$14M	\$61M
TOTAL	**\$150M**	**\$65M**	**\$85M**

Q. WHAT DOES AEP OHIO EXPECT TO ACHIEVE WITH gridSMART® - PHASE 1 THROUGH THE END OF THE 2013 EVALUATION PERIOD?

A. AEP Ohio continues to make significant progress in the implementation and achievement of the gridSMART® – Phase 1 Program. More than 99 percent of the

110,000 advanced metering infrastructure (AMI) meters approved in the 2009 ESP have been deployed. This is important because it provides AEP Ohio the opportunity to work with a broad base of AMI meters in a "real world" environment. The Home Area Network (HAN), which is the interface between the AMI meter and the customer, is also progressing well. The preliminary design and engineering have been completed. A small number of deployments of the HAN technology are under development. The 2009 ESP also approved the installation of Distribution Automation (DA) on 70 circuits. DA is currently operational on 8 circuits and there are another 32 circuits with DA installed that are ready to be commissioned. Plans for DA to be installed on the remaining 30 circuits are under development.

Other initiatives being developed in gridSMART® – Phase 1 include the enhancements required by the DOE to successfully receive the matching funds. In addition to implementation of all the initiatives, the DOE requires 24 months of data collection and analysis which will occur in 2012 and 2013. It is expected that upon completion of the gridSMART® – Phase 1 Program, AEP Ohio will be in a position to implement gridSMART® to all of the AEP Ohio customers. Additionally, AEP Ohio will be positioned to evaluate the feasibility of implementing the additional DOE initiatives if the Demonstration Project shows them to be of value to AEP Ohio consumers.

Q. PLEASE DESCRIBE THE gridSMART® - PHASE 1 PLAN GOING FORWARD?

A. The Company is prepared to maintain the existing rider for the recovery of the cost of assets already installed or planned to be installed as part of the completion of gridSMART® – Phase 1 and the Demonstration Project. The rider is proposed to be continued through the completion of the gridSMART® Demonstration Project, which is expected to be completed December 31, 2013. Upon completion of the gridSMART® – Demonstration Project, the rider assets could be included in rate base in a future distribution rate case or other regulatory filing. Please see Company witness Moore for explanation of the existing gridSMART® rider recovery mechanism.

Q. PLEASE DESCRIBE THE IMPLEMENTATION PLAN FOR gridSMART® OVER THE NEXT TEN YEARS.

A. The long-term implementation of gridSMART® assets will be discussed by Company witness Kirkpatrick.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY OF
THOMAS E. MITCHELL
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed January 27, 2011

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THOMAS E. MITCHELL

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
THOMAS E. MITCHELL
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas E. Mitchell and my business address is 1 Riverside Plaza Columbus, Ohio 43215.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) or collectively referred to as AEP Ohio or the Company.

BUSINESS EXPERIENCE

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), as Managing Director of Regulatory Accounting Services. AEP is the parent company of CSP and OPCo.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF REGULATORY ACCOUNTING SERVICES?

A. My primary responsibilities include providing the AEP System operating subsidiaries, including CSP and OPCo, with accounting support for regulatory filings. This support includes the preparation of cost-of-service adjustments, accounting schedules, and accounting testimony. I direct a group of professionals who provide accounting expertise, compile necessary historical accounting schedules, present expert accounting testimony and respond to data requests in connection with rate filings with eleven regulatory commissions and the Federal Energy Regulatory Commission (FERC).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Accounting from Virginia Polytechnic Institute and State University (Virginia Tech) in 1977. I also hold a Master of Business Administration Degree from Virginia Tech and a Bachelor of Arts Degree in Government from the University of Notre Dame. I have been a Certified Public Accountant since 1978. I was first employed by Appalachian Power Company (APCo) in 1979, an affiliated operating company of CSP and OPCo and, except for employment with Norfolk Southern Corporation as an Assistant Accounting Manager (1984-1985), have held various positions in the Accounting Department continuously since that date. In 1998, I was promoted to Director, Accounting Policy & Research and in 2008, I was promoted to my present position as Managing Director of Regulatory Accounting Services. I have served as Chairman of the Accounting Standards Committee of the Edison Electric Institute (EEI) and am currently Chairman of the Joint Accounting Liaison Committee of the EEI which meets annually with the FERC Accounting Staff to discuss accounting issues of mutual interest to EEI and the FERC.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A COMMISSION?

A. Yes, I recently testified on behalf of CSP and OPCo before the Public Utilities Commission of Ohio (PUCO or the Commission) in the 2009 Significantly Excessive Earnings Test (SEET) proceedings, Case No. 10-1261-EL-UNC. In addition, I have filed accounting testimony and testified on behalf of APCo and Wheeling Power Company before the Public Service Commission of West Virginia, and on behalf of APCo before both the Virginia State Corporation Commission and the FERC. I have also filed accounting testimony on behalf of Indiana Michigan Power Company before the Indiana Utility Regulatory Commission.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the accounting related to the Fuel Adjustment Clause (FAC) for the phase-in deferred fuel balances applicable to the 2009 - 2011 (2009 - 2011) Electric Security Plan (ESP), the accounting for the FAC mechanism for the proposed 2012 - May 2014 (2012 - 2014) ESP, the recovery of regulatory assets in the 2009 - 2011 ESP which is proposed to be continued under the proposed 2012 - 2014 ESP and the over/under recovery accounting proposed in the 2012 - 2014 ESP. In addition, I provide comments on certain proposed deferrals for future recovery.

FAC ACCOUNTING FOR PHASE-IN DEFERRED FUEL BALANCES APPLICABLE TO THE 2009-2011 ESP

Q. AT AUGUST 31, 2010 WHAT ARE THE AMOUNTS TO BE COLLECTED FROM CUSTOMERS RELATED TO CSP'S AND OPCO'S DEFERRED UNRECOVERED FUEL APPLICABLE TO THE 2009 - 2011 ESP?

A. At August 31, 2010 CSP and OPCo have amounts to be collected from customers of $17 million and $439 million, respectively for the unrecovered fuel related to the 2009 - 2011 ESP. The unrecovered fuel amounts to be collected from customers for CSP and OPCo are projected to be approximately zero and $643 million at December 31, 2011, respectively, as discussed by Company witness Nelson regarding the Phase-In Recovery Rider (PIRR). See the tables below for the components of the current and projected FAC phase-in underrecovered costs which include carrying costs.

CSP: Description	Actual August 31, 2010 (Millions)	Projected December 31, 2011 (Millions)
Unrecovered Fuel Cost - OH	$14	$-
Carrying Charges - OH FAC	3	-
Total to be Collected	$17	$-

OPCO: Description	Actual August 31, 2010 (Millions)	December 31, 2011 (Millions)
Unrecovered Fuel Cost - OH	$400	$535
Carrying Charges - OH FAC	39	108
Total to be Collected	$439	$643

Q. ARE CSP AND OPCO CURRENTLY USING THE CARRYING COST RATE APPROVED IN THE 2009 – 2011 ESP?

A. Yes. CSP and OPCo use a Weighted Average Cost of Capital (WACC) rate which includes a Return on Equity and a monthly variable long-term debt rate applied to actual phase-in deferred balances.

Q. IF SECURITIZATION OF THIS BALANCE AS DISCUSSED BY COMPANY WITNESS HAWKINS IS APPROVED, HOW WOULD THE COMPANY ACCOUNT FOR THE SECURITIZATION?

A. If the Company securitizes its phased-in regulatory asset, the balance of the regulatory asset to be securitized (including carrying charges) at the time of securitization will become a securitization asset along with the cost of the securitization, and the securitized debt will be recorded as long-term debt. The securitization asset would be amortized to expense commensurate with its recovery from ratepayers over the approved recovery period to match the revenues collected from ratepayers. The equity would be recognized as the securitized debt is paid by ratepayers over the approved recovery period. The amounts collected from ratepayers would be applied to interest and principal payments due on the securitized debt. The need for a WACC carrying cost on the balance of the regulatory asset securitized would cease at the point of securitization because the securitized debt reimburses the Company for the phase-in deferral amounts.

Q. PLEASE EXPLAIN THE ACCOUNTING TO BE EMPLOYED IF SECURITIZATION BONDS ARE NOT ISSUED.

A. As indicated by Company witness Hawkins, the PUCO order in ESP Case Nos. 08-917-EL-SSO and 08-918-EL-SSO authorized the recovery of the deferred unrecovered fuel over the 2012 - 2018 period via a nonbypassable surcharge (PIRR discussed by Company witness Moore). Assuming the PUCO authorizes such recovery, OPCo would continue to record a WACC carrying cost including a monthly variable long-term debt rate and an ROE of 11.15% (refer to Company witness Hawkins' testimony) on the unrecovered balance of the regulatory asset from January 1, 2012 through December 31, 2018 and the regulatory asset will be amortized commensurate with the recovery via the PIRR of such phase-in deferred fuel costs over the seven year recovery period from 2012 through 2018.

FAC MECHANISM FOR THE 2012 - 2014 ESP

Q. WHAT IS THE COMPANY PROPOSING REGARDING AN ONGOING FUEL COST RECOVERY MECHANISM?

A. As discussed by Company witness Nelson, the Company is proposing the continuation of the on-going FAC true-up cost recovery mechanism approved in the current ESP case. In that regard, as discussed by Company witness Nelson, the Company is proposing to implement a FAC mechanism which will recover, beginning in January 2012, estimated incremental fuel costs including quarterly true-up of the recoveries to actual fuel costs.

Q. PLEASE SPECIFICALLY EXPLAIN WHAT YOU MEAN BY FUEL CLAUSE UNDER/OVER DEFERRAL TRUE-UP ACCOUNTING THAT THE COMPANY WILL EMPLOY STARTING IN 2012.

A. Specifically, under actual fuel clause under/over recovery true-up calculations and deferral accounting (over/under), any under recovery would be deferred in Account 182.3, Other Regulatory Assets, with a credit to fuel expense in Account 501, and recovered through the FAC over the next fuel clause period. Any over-recovery would be deferred as a regulatory liability in Account 254, Other Regulatory Liabilities, with a charge to fuel expense in Account 501, Fuel, and refunded to ratepayers through the FAC over the next fuel clause period. The Company is not proposing any carrying cost since the Company will be adjusting the fuel rates quarterly for the period beginning January 1, 2012

Q. ARE THERE ANY PROPOSED CHANGES THAT IMPACT THE ACCOUNTING FOR OVER/UNDER RECOVERY OF THE FAC MECHANISM?

A. Yes. Company witness Roush describes the Market Transition Rider (MTR) for which the over/under effect is proposed to be included in the FAC reconciliation. Also Company witness Nelson proposed the Alternative Energy Rider (AER) to capture Renewable Energy Credit costs that previously were recovered in the FAC.

<u>OVER/UNDER RECOVERY ACCOUNTING FOR NON-FAC RIDERS</u>

<u>OVERVIEW OF OVER/UNDER RECOVERY AND CARRYING CHARGES</u>

Q. SEVERAL OF THE COMPANY'S WITNESSES HAVE PROPOSED ESP RIDERS THAT WOULD INCLUDE OVER/UNDER ACCOUNTING. PLEASE SUMMARIZE THE BASIS FOR OVER/UNDER ACCOUNTING.

A. Statement of Financial Accounting Standards (SFAS) No. 71 [now known as Financial Accounting Standards Board's Accounting Standards Codification (FASB ASC) 980] requires deferral accounting when a regulatory commission requires future rates to be reduced to refund an over recovery and when a regulatory commission provides for the future recovery of incurred expenses or it is probable that a regulatory commission will provide for such future recovery of an incurred expense. Therefore, in order to record regulatory liabilities or regulatory assets and perform regulatory deferral over/under recovery true-up accounting, it must be probable that the regulatory liability will be refunded or that the regulatory asset will be recovered in the future.

Q. WHAT IS NEEDED TO ESTABLISH PROBABILITY AND THUS MEET THE ACCOUNTING CRITERIA FOR RECORDING A REGULATORY LIABILITY OR ASSET FOR THESE RIDERS?

A. In order to meet the probability standard, the final order in this proceeding should clearly provide for both the future recovery or the future refund in the next applicable filing of any difference between incurred expenses (plus a carrying cost where appropriate) compared with the actual revenues collected. The next applicable filing will typically be determined by the Commission setting the dates for annual true-ups.

Q. WHAT ACCOUNTING IS EMPLOYEED WHEN OPERATION AND MAINTENANCE (O&M) COSTS ARE PART OF OVER/UNDER ACCOUNTING?

A. If the monthly actual incurred O&M expenses are less than the monthly approved revenues, the Company will credit a regulatory liability and charge the appropriate O&M expense accounts. Similarly, if the monthly actual incurred O&M expenses are more than the monthly approved revenues, the Company will charge a regulatory asset while crediting the appropriate O&M expense accounts. These deferral entries ensure a zero impact on income.

Q. ARE CERTAIN RIDERS DESIGNED TO RECOVER COSTS OTHER THAN O&M?

A. Yes. Certain riders also include either a WACC or a carrying cost on capital assets. As discussed by Company witness Nelson, the carrying cost rate on the capital assets includes a WACC (discussed by Company witness Hawkins), a depreciation component, an income tax component, property and other taxes component and an administrative and general component. The next section of my testimony identifies the type of carrying cost for the Company's proposed non-FAC riders with over/under accounting.

<u>PROPOSED NON-FAC RIDERS WITH OVER/UNDER RECOVERY ACCOUNTING</u>

Q. WAS OVER/UNDER ACCOUNTING UTILIZED FOR RIDERS APPROVED IN THE 2009 - 2011 ESP PLAN AND IS OVER/UNDER ACCOUNTING PROPOSED TO BE CONTINUED IN THE 2012 - 2014 ESP?

A. Yes. In addition to the over/under recovery employed for the FAC discussed previously, over/under accounting was used for several riders in the 2009 - 2011 ESP. Generally the riders approved in the 2009 - 2011 ESP included over/under accounting applying FASB ASC 980 with the exception of the Environmental Investment Carrying Cost Rider (EICCR) and the Provider of Last Resort (POLR). The non-FAC riders approved in the 2009 - 2011 ESP with over/under recovery are summarized in the table below, including the Company witnesses who propose continuation of such riders in the 2012 - 2014 ESP.

Rider Description	Carrying Cost(CC) Type	Company Witness
gridSMART® Rider	Carrying Cost on Capital Assets	Sloneker, Moore
Enhanced Service Reliability Rider (ESRR)	Carrying Cost on Capital Assets	Kirkpatrick, Moore
Economic Development Rider (EDR)	Debt Carrying Cost on Unrecovered Balance	Moore
Transmission Cost Recovery Rider (TCRR)	Debt Carrying Cost on Unrecovered Balance	Hamrock, Moore
Energy Efficiency and Peak Demand Reduction (EE/PDR) Rider	None	Sloneker, Moore

Q. ARE THERE ADDITIONAL NON-FAC RIDERS PROPOSED BY THE COMPANY IN THE 2012 - 2014 ESP THAT INCLUDE OVER/UNDER ACCOUNTING?

A. Yes. In addition to continuing the over/under accounting for the non-FAC riders in the table above, the riders listed in the table below would employ over/under accounting.

Rider Description	Carrying Cost(CC) Type	Company Witness
Generation Resource Rider (GRR)	CC on Capital Asset	Nelson, Roush
EICCR	CC on Capital Asset	Nelson, Moore
Distribution Investment Rider (DIR)	WACC – Net Plant	Kirkpatrick, Moore
Facility Closure Cost Recovery Rider (FCCR)	WACC on Unrecovered Balance	Thomas, Moore
Generation NERC Compliance Cost Recovery Rider (NERCR)	CC on Capital Asset	Thomas, Moore
AER	None	Nelson

Rider Description	Carrying Cost(CC) Type	Company Witness
Carbon Capture and Sequestration Rider (CCSR)	CC on Capital Asset	Nelson

FACILITY CLOSURE COST RECOVERY

Q. COMPANY WITNESS THOMAS DISCUSSES THE PROPOSED RECOVERY OF CERTAIN COSTS THROUGH THE FCCR. WHAT ACCOUNTING WILL BE EMPLOYED FOR THE FCCR?

A. The Company will use regulatory accounting with over/under recovery to account for these costs similar to the other riders discussed previously in my testimony. This approach will ensure that the actual costs incurred are recovered, particularly since not all costs are known when the applicable assets are retired, due to future removal costs and salvage, as examples.

Q. IN REGARD TO THE FCCR, IF ONE OF THE COMPANY'S GENERATING FACILITIES IS SHUT DOWN AT AN EARLIER DATE THAN ITS CURRENT DEPRECIATION RETIREMENT DATE, WHAT WOULD BE THE ACCOUNTING IMPLICATIONS ABSENT ANY SPECIAL RATEMAKING/ACCOUNTING?

A. If an early unanticipated shut down of a generating facility occurs, there will be an undepreciated remaining investment in Account 101, Electric Plant In Service, which would have to be expensed absent regulatory recovery. For CSP, any unamortized deferred investment tax credit (DITC) balance would provide some offset to the expense, but for OPCo no DITC is available. Also there would be additional losses for related materials and supplies not able to be used at other facilities as well as asset retirement obligations (ARO) and other closure costs. The resultant net loss would be recognized as an expense absent any special ratemaking/accounting treatment.

DEFERRALS FOR FUTURE RECOVERY

Q. IS THE COMPANY SEEKING ADDITIONAL DEFERRAL ACCOUNTING TO RECORD REGULATORY ASSETS OR LIABILITIES FOR FUTURE RECOVERY/REFUND IN TARIFFS?

A. Yes. As requested by Company witnesses Kirkpatrick and Moore for the Storm Damage Recovery Mechanism and Company witnesses Moore and Sloneker for the Plug-In Electric Vehicle (PEV) Costs, the Company is proposing the deferral of certain costs. Also, Company witness Kirkpatrick requests deferral of the net-book value (NBV) of retired meters and recovery in a future filing associated with expansion of gridSMART®.

Q. WOULD THE DEFERRAL OF COSTS FOR FUTURE RECOVERY BE SUBJECT TO THE SAME FASB ASC 980 STANDARD DISCUSSED PREVIOUSLY?

A. Yes. Any new deferrals would need to be probable of recovery in order to be established.

Q. PLEASE SUMMARIZE THE ACCOUNTING FOR THE COMPANY'S PROPOSED STORM DAMAGE RECOVERY MECHANISM.

A. As discussed by Company witnesses Kirkpatrick and Moore, the Company is proposing to implement a Storm Damage Recovery Mechanism for distribution. If approved, the Company will defer the actual expense above or below the storm expense included in base level expenses for future recovery (see discussion by Company witnesses Kirkpatrick and Moore for base level expense calculation) beginning with the effective date of a final order in this case.

Q. PLEASE SUMMARIZE THE ACCOUNTING FOR THE COMPANY'S PROPOSED PEV DEFERRAL.

A. As discussed by Company witness Moore, the Company is proposing that the costs associated with the installation of infrastructure necessary to charge the PEV battery be deferred for future recovery. If the request is approved, the Company would record a regulatory asset for future recovery instead of expensing the Company's reimbursement to customers for a portion of their PEV costs.

Q. PLEASE SUMMARIZE THE ACCOUNTING FOR THE COMPANY'S PROPOSED DEFERRAL OF THE NBV OF RETIRED METERS ASSOCIATED WITH gridSMART®.

A. Typically the NBV of retired meters is charged to Account 108, Reserve for Accumulated Depreciation, along with the net removal cost (net of salvage) for cost-based regulated companies. This accounting provides for recovery of the undepreciated balances and the net cost of removal over the remaining life of the assets in the mass property accounts which would result in an increase in the on-going composite depreciation rates in the next depreciation study. However, a mass premature retirement to be replaced with smart meters is a significant retirement for which probability of recovery must be demonstrated as in effect, a regulatory asset has been established. As a result, Company witness Kirkpatrick has requested that the estimated remaining book value of the existing meters replaced and retired in mass together with the net removal costs associated with gridSMART® be deferred for future recovery.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY
OF
ANDREA E. MOORE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: January 27, 2011

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ANDREA E. MOORE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
ANDREA E MOORE
ON BEHALF OF
COLUMBUS SOUTHERN POWER
AND
OHIO POWER COMPANY

PERSONAL DATA

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Andrea E. Moore and my business address is 850 Tech Center Drive, Gahanna, Ohio 43230.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation as Manager, Regulated Pricing and Analysis for Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo), collectively known as AEP Ohio or the Company. AEPSC is a subsidiary of the American Electric Power Company Inc. (AEP) and provides technical and other services to AEP Ohio and other operating units within the AEP System. In 2009, I began focusing solely on AEP Ohio's regulated pricing matters.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER – REGULATED PRICING AND ANALYSIS?

A. I am responsible for directing the preparation and presentation of regulatory matters to management as well as regulatory bodies. I plan, organize and direct team activities to develop and support pricing structures, rider and true-up filings, maintenance of tariffs, pilot programs, special contracts and other pricing initiatives depending on assigned function.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received my Bachelor of Science in Accounting degree from the University of Rio Grande. I completed the Basic Concepts of Rate Making class through New Mexico State University. I earned a Master of Business Administration degree from Franklin University. I joined AEPSC in 2001 as an Accountant and joined the Regulatory Tariffs department as a Regulatory Analyst III in 2004. I progressed through various positions before being promoted to my current position of Manager – Regulated Pricing and Analysis. My duties within the regulatory department have included preparing cost-of-service studies for regulatory filings, preparing cost based formula rates for wholesale customers, preparing rider filings and rate designs, maintaining tariff books as well as other projects related to regulatory issues and proceeding, individual customer requests and general rate matters.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN A REGULATORY PROCEEDING?

A. Yes. I have filed testimony before the Virginia State Corporation Commission.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's proposal for a new Plug-In Electric Vehicle (PEV) tariff and a storm damage recovery mechanism.

In addition, I am supporting the continuation of some current riders, an updated collection method of other current riders and proposed collection methods of new riders:

<u>Current Rider Modifications</u>

- Provider of Last Resort (POLR) – Modification supported by Company witness Thomas
- Fuel Adjustment Clause (FAC) – Modification supported by Company witness Nelson
- Environmental Investment Carrying Cost Rider (EICCR) – Modification supported by Company witness Nelson
- Transmission Cost Recovery Rider (TCCR) – No Modification requested

<u>Current Rider Proposed Rate Change</u>

- Energy Efficiency and Peak Demand Reduction Rider (EE/PDR) – Rate change to calculate one AEP Ohio rate
- Enhanced Service Reliability Rider (ESRR) – Rate change to calculate one AEP Ohio Rate
- gridSMART® Rider – Rate change to calculate one AEP Ohio rate
- Economic Development Rider (EDR) - Rate change to calculate one AEP Ohio rate
- Universal Service Fund (USF) – Rate change to calculate one AEP Ohio Rate

<u>Proposed Rider Rate Design</u>

- Distribution Investment Rider (DIR)

- Facility Closure Cost Recovery Rider (FCCRR)
- North American Electric Reliability Corporation (NERC) Compliance Cost Recovery Rider (NERCR)
- Alternative Energy Rider (AER)
- Phase-In Recovery Rider (PIR)

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring Exhibits AEM-1 through AEM-4.

Exhibit AEM-1 - Calculation of EICRR

Exhibit AEM-2 - Calculation of gridSMART®, ESRR, EDR and EE/PDR rates

Exhibit AEM-3 - Calculation of USF Rider

Exhibit AEM-4 - Calculation of Distribution Investment Rider

NEW PLUG-IN ELECTRIC VEHICLE TARIFF

Q. PLEASE EXPLAIN THE PLUG-IN ELECTRIC VEHICLE (PEV) TARIFF.

A. The Company is prosing to implement a tariff for PEVs. The Company would like to offer reimbursements to customers for installing charging infrastructure that would support vehicle charging during the off-peak hours. The Company requests the costs associated with these reimbursements be deferred at a weighted average cost of capital (WACC) for collection in a future proceeding. Company witness Hawkins supports the calculation of the WACC. The Company requests that the kilowatt hour (kWh) associated with any PEV load not be counted towards the baseline in the energy calculation for energy efficiency mandates. The PEV tariff is further discussed in Company witness Sloneker's testimony.

Q. WHAT CONDITIONS AND COSTS WOULD BE ASSOCIATED WITH THE PEV CHARGING INFRASTRUCTURE?

A. The PEV must be registered and operable on public highways in the state of Ohio. The Company will reimburse the customer up to $2,500 for the equipment and installation of the infrastructure necessary to charge the PEV battery. A time-of-use (TOU) or AMI meter will be installed at the Company's discretion at no cost to the customer.

Q. WHY IS A SEPARATE TIME-OF-USE OR AMI METER REQUIRED?

A. A TOU or AMI meter is required in order to measure energy consumption during the on-peak and off-peak billing periods. If the customer does not choose to meter the entire premises on a time-differentiated rate, they may continue receiving service of their general-use load through a standard residential meter on Schedule Residential Service (RS) and have the TOU meter installed to require only the vehicle charging to be subject to time-differentiated rates. The additional meter will separately meter this load and the applicable rates of the PEV tariff will be charged.

Q. WHAT ARE THE TARIFF PROVISIONS FOR THE PEV?

A. The Company will limit the participation to the first 200 residential customers that apply for the tariff. The rate structure for the PEV tariff will be the same as the current residential energy storage tariff that offers a discount on kWh used during the off-peak period. Because the outlet for the PEV will be separately metered, this should encourage customers with PEV to charge the batteries in the off-peak hours. Additional provisions have been made to the residential service tariff to incorporate the inclusion of PEVs to the time-of-day metered accounts.

STORM DAMAGE RECOVERY MECHANISM

Q. PLEASE EXPLAIN THE STORM DAMAGE RECOVERY MECHANISM.

A. The Storm Damage Recovery Mechanism is necessary for the Company to efficiently fund Operating and Maintenance (O&M) expenses as they relate to major storm events, as described by Company witness Kirkpatrick. The Company is proposing an over/under recovery mechanism that will be used to collect the O&M cost of major storms that is currently not included in rates. The five year average of O&M storm expense, excluding costs associated with Hurricane Ike is $8.9 million. On a monthly basis the Company will measure the amounts spent for O&M on major storm restoration against the major storm baseline cost. If the Company spends more than the baseline amount, the difference will be recorded as a regulatory asset in that month. If the Company spends less than the baseline amount the difference will be recorded as a regulatory liability in that month. Company witness Mitchell discusses the accounting if this proposal.

Q. IS THE MONEY BEING COLLECTED FOR THE STORM DAMAGE RECOVERY MECHANISM GOING TO BE MAINTAINED IN A SEPARATE FUND?

A. No. This is simply an accounting mechanism.

CONTINUATION OF COMPANY RIDERS

Q. IS THE COMPANY REQUESTING THE CONTINUATION OF ANY RIDERS?

A. Yes. The Company is requesting that all riders approved in the previous Electric Security Plan (ESP) continue. These riders include the Provider of Last Resort (POLR) Rider, Transmission Cost Recovery Rider (TCRR), Fuel Adjustment Clause (FAC), Energy Efficiency and Peak Demand Reduction (EE/PDR), Economic Development Rider (EDR), Enhanced Service Reliability Rider (ESRR), gridSMART® rider and the Environmental Investment Carrying Cost Rider (EICCR).

Q. IS THE COMPANY PROPOSING ANY MODIFICATION TO THE ENVIRONMENTAL INVESTMENT CARRYING COST RIDER (EICCR)?

A. Yes. The Company is requesting a change in the EICCR. The Company is recommending that the environmental capital expenditures spent to date, including future capital expenditures, be maintained in this EICCR. The capital environmental expenditures spent in 2009 were designed to be collected through the end of the 2009-2011 ESP period or December, 2011. The current rider is designed to collect in 2011 environmental capital costs spent in 2010 and to collect in 2012 environmental capital costs spent in 2011. The Company is requesting that beginning with the 2012 filing, a forecast of spending be incorporated into the rider to eliminate the lag between expenditures and recovery. The filing will be trued up annually which will allow the compounding carrying costs currently implemented to be excluded with this new mechanism to reflect current recovery. The Company is also requesting that beginning January 2012, the environmental rider will include environmental O&M. Company witness Nelson discusses this rider.

Q. IS THE COMPANY RECOMMENDING A CHANGE IN THE CURRENT EICCR RATE?

A. Yes. The Company is proposing that the environmental rider rate be calculated to reflect one rate for AEP Ohio. In addition, the Company is proposing to change the collection method from an overall percentage of base generation charge to a per kWh charge by class. To compute the rate for each class, the EICCR revenue requirement will be allocated based on the class percentage of base generation revenue in relation to total base generation revenue. A rate per kWh for each class will be calculated based upon class generation kWh. Finally, all rates will be scaled down to reflect the difference between total metered kWh and total generation kWh. The resultant rates will apply to all kWh of each class, shopping and non-shopping. Exhibit AEM-1 reflects this change and shows the calculation based on 2009 through 2011 expenditures, as well as a forecast of 2012 expected expenditures. Because the Company is expecting this rate to become effective in January 2012, the first true up filing for the new EICRR will be in February, 2013. Exhibit AEM-1 shows the calculation of the new EICCR rate for each class.

Q. IS THE COMPANY REQUESTING ANY MODIFICATION TO THE GRIDSMART® RIDER?

A. No. The Company is only requesting to update the amount of expenditures for gridSMART® Phase I. These forecast expenditures will be included in the Company's annual gridSMART® true-up filing. The Company is proposing the prudence of these costs to continue to be determined as part of the annual true-up filing in February each year. Company witnesses Sloneker and Kirkpatrick discuss the gridSMART® program.

Q. IS THE COMPANY PROPOSING A CHANGE IN THE CURRENT GRIDSMART® RIDER RATE?

A. Yes. The Company is proposing to reflect one rate for AEP Ohio. Exhibit AEM-2 reflects this change and results in the AEP Ohio gridSMART® rider being $0.27 per residential bill and $1.00 per non-residential bill, as of the date of this filing. This is simply the result of spreading the same level of costs over a larger number of customers.

Q. IS THE COMPANY REQUESTING ANY MODIFICATION TO THE ENHANCED SERVICE RELIABILITY RIDER (ESRR)?

A. No. The Company is only requesting to update the amount of expenditures for the ESRR in years 2012, 2013 and 2014. As described by Company witness Kirkpatrick, the transition to a cycle based vegetation management program is expected to take 5 years. The Company is requesting to add the costs associated with the final two years of the original 5 year plan as well as a maintenance level for 2014. The prudence of these new costs as well as the old costs will continue to be determined as part of the annual true-up filing in February each year. Company witness Kirkpatrick discusses this rider.

Q. IS THE COMPANY PROPOSING A CHANGE IN THE CURRENT ESSR RATE?

A. Yes. The Company is proposing to reflect one rate for AEP Ohio. Exhibit AEM-2 reflects this change and results in the AEP Ohio ESRR rate being 4.58062% of base distribution revenues, as of the date of this filing.

Q. IS THE COMPANY PROPOSING A MODIFICATION IN THE CURRENT ECONOMIC DEVELOPMENT RIDER (EDR)?

A. No. The company is requesting that the Economic Development rider continue as is and be updated biannually as ordered by the Commission.

Q. IS THE COMPANY PROPOSING A CHANGE IN THE CURRENT EDR RATE?

A. Yes. The Company is proposing to reflect one rate for AEP Ohio. Exhibit AEM-2 reflects this change and results in the AEP Ohio EDR rate being 9.63500% of base distribution revenues, as of the date of this filing.

Q. IS THE COMPANY PROPOSING A MODIFICATION IN THE CURRENT ENERGY EFFICIENCY/PEAK DEMAND REDUCTION RIDER (EE/PDR)?

A. No. The Company is requesting that the EE/PDR rider continue to be set through a separate filing as done currently and be updated annually each year as ordered by the Commission. During 2011, the Company will be filing a new program portfolio plan (POR) to update its plan for 2012 through 2014.

Q. IS THE COMPANY PROPOSING A CHANGE IN THE CURRENT EE/PDR RATE?

A. Yes. The Company is proposing to reflect one rate for AEP Ohio. Exhibit AEM-2 reflects this change and results in the AEP Ohio EE/PDR rate being

0.28902¢/kWh for residential customers, 0.03845¢/kWh for GS-4 and Interruptible customers, and 0.26773¢/kWh for all other customers, as of the date of this filing.

Q. IS THE COMPANY PROPOSING ANY MODIFICATION TO THE TRANSMISSION COST RECOVERY RIDER (TCRR)?

A. No. The Company is requesting that the TCRR continue to be in effect during the ESP and that the rate be updated through an annual filing. The proposal of one rate for AEP Ohio will be addressed in the 2011 TCRR filing.

Q. IS THE COMPANY PROPOSING A MODIFICATION IN THE CURRENT UNIVERSAL SERVICE FUND (USF) RIDER?

A. No. This rider is administered by the Ohio Department of Development and will continue to be filed and proposed by that organization.

Q. IS THE COMPANY PROPOSING A CHANGE IN THE CURRENT USF RATE?

A. Yes. The Company is proposing to reflect one rate for AEP Ohio. Exhibit AEM-3 reflects this change and results in the AEP Ohio USF rate being 0.24312¢/kWh for the first 833,000 kWh consumed and 0.038451731¢/kWh for all kWh consumed in excess of 833,000.

<u>ADDITIONAL RIDERS</u>

Q. IS THE COMPANY REQUESTING ANY ADDITIONAL RIDERS?

A. Yes. In addition to keeping the above mentioned riders in place, the Company is requesting the approval of a Distribution Investment Rider, Facility Closure Cost

Recovery Rider, Generation NERC Compliance Cost Recovery Rider, Alternative Energy Rider, and Phase-In Recovery Rider.

Q. PLEASE EXPLAIN THE DISTRIBUTION INVESTMENT RIDER (DIR).

A. The Company is requesting the approval of a rider that will allow carrying costs on incremental distribution plant to be recovered each year using a Pre-tax WACC as well as an O&M component as sponsored by Company witness Kirkpatrick.

Q. WILL THIS DIR BE REQUIRED IF THE COMPANY HAS A DISTRIBUTION BASE RATE CASE APPROVED PRIOR TO THE START OF THE PROPOSED 2012-2014 ESP?

A. No. The Company is requesting a similar DIR in its 2011 distribution rate case. Depending on the timing of the outcome of that case, the Company is proposing an interim recovery mechanism to account for the net plant increase that has occurred since the Company first set unbundled distribution rates in 2000.

Q. PLEASE DESCRIBE THE INTERIM DIR MECHANISM.

A. Exhibit AEM-4 shows the methodology for calculating the revenue requirement for the DIR. In Case Nos. 05-842-EL-ATA and 05-843-EL-ATA, the Company received an increase in base distribution rates and offsetting decrease in transmission rates. The distribution revenue increase associated with these cases will be removed from the current distribution revenue requirement. Also deducted will be the revenue requirement related to distribution capital expenditures already established through the ESRR. The net plant of the solar panels for both the Newark and Athens Distribution centers as well as the net plant for gridSMART® will be removed to reflect collection of these costs through other riders. Company witness Kirkpatrick testifies to the need for investment in distribution assets for the future. The Company is proposing to update this rider quarterly based on the incremental increase in the net plant balance as shown on Form 3Q, which is filed quarterly with the Federal Energy Regulatory Commission (FERC). The adjustments associated with ESRR will be calculated annually, after the audit for the ESRR has taken place. The adjustment for the solar panels and gridSMART® assets will be updated quarterly with the DIR filing. This rider will be subject to over/under recovery. Because the costs are directly related to the Company infrastructure, the rider will be collected as a percentage of base distribution revenue. The initial rate, if necessary, will be set in a separate proceeding before this Commission.

Q. PLEASE EXPLAIN THE FACILITY CLOSURE COST RECOVERY RIDER.

A. The details of the costs to be recovered through the Facility Closure Cost Recovery Rider are explained in Company witness Thomas' testimony. These costs will be multiplied by the pre-tax WACC in calculating the revenue requirement. The rider will be structured as a nonbypassable per kWh rider. To compute the rate for each class, the facility closure revenue requirement will be allocated based on the class percentage of base generation revenue in relation to total base generation revenue. A rate per kWh for each class will be calculated based upon class generation kWh. Finally, all rates will be scaled down to reflect the difference between total metered kWh and total generation kWh. The resultant rates will apply to all kWh of each class, shopping and non-shopping.

Q. PLEASE EXPLAIN THE GENERATION NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC) COMPLIANCE COST RECOVERY RIDER.

A. The details of the costs to be recovered through the Generation NERC Compliance Cost Recovery Rider are explained in Company witness Thomas' testimony. The Costs associated with NERC Compliance will be subject to a levelized carrying charge as shown in Exhibit PJN-2. The rider will be structured as a nonbypassable per kWh rider. To compute the rate for each class, the facility closure revenue requirement will be allocated based on the class percentage of base generation revenue in relation to total base generation revenue. A rate per kWh for each class will be calculated based upon class generation kWh. Finally, all rates will be scaled down to reflect the difference between total metered kWh and total generation kWh. The resultant rates will apply to all kWh of each class, shopping and non-shopping.

Q. PLEASE EXPLAIN THE ALTERNATIVE ENERGY RIDER.

A. As Company witness Nelson describes, the Alternative Energy Rider (AER) will include Renewable Energy Credits (RECs). This rider will be a bypassable per kWh rider and will be adjusted quarterly along with the FAC.

Q. PLEASE EXPLAIN THE PHASE-IN RECOVERY RIDER.

A. As Company witness Nelson describes, the deferred fuel balance will be recovered as a uniform per kWh nonbypassable charge over a 7-year period as approved in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO. However, the potential benefits of securitization are described by Company witness Hawkins.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Estimate of 2012 Environmental Investment Carrying Charge Rider

In Thousands

Line No.	Description	CSP	OPCo	AEP Ohio
1	2009 Actual	$ 73,838	$ 148,928	$ 222,766
2	2010 Estimate	$ 76,620	$ 67,463	$ 144,083
3	2011 Estimate	$ 20,614	$ 49,443	$ 70,057
4	2012 Estimate	$ 18,841	$ 30,115	$ 24,478 *
5	Total Capital Expenditures	$ 189,913	$ 295,949	$ 461,384
6	Levelized Carrying Cost Rate			14.11%
7	Total Capital Carrying Cost			$ 65,101
8	Estimated Annual O&M Expense			$ 28,000
9	Total Annual Revenue Requirement			$ 93,101
10	Capacity Allocation (Estimated)			80.00%
11	Retail & Firm Wholesale Annual Revenue Requirement			$ 74,481
12	Retail Allocation Factor			95.60%
13	Retail Annual Revenue Requirement			$ 71,204

* Represents a half-year convention

1 Actual Environmental Capital Expenditures from Case No. 10-0155
2 Estimated Environmental Capital Expenditures for 2010
3 Estimated Environmental Capital Expenditures for 2011
4 Estimated Environmental Capital Expenditures for 2012
5 Sum of Lines 1 through 4
6 25 Yr rate from PJN-2, Adjusted to Remove Property Taxes
7 Line 5 Times Line 6
8 Estimated O&M Associated with Post 2008 Environmental Equipment Excluding FAC Expenses
9 Line 7 Plus Line 8
10 Estimated Pool Capacity Allocation to Other Pool Members
11 Line 9 Times Line 10
12 Estimated Retail Allocation Factor
13 Line 11 Times Line 12

Estimate of 2012 Environmental Investment Carrying Charge Rider

Line No.			Residential	GS-1	GS-2	Area Lighting	Street Lighting	Total
1	Base Generation Revenue By Class	CSP	$ 157,701,619	$ 16,702,179	$ 257,014,597	$ 1,575,773	$ 752,158	
2		OPCo	$ 183,332,199	$ 12,989,914	$ 358,279,723	$ 2,983,986	$ 2,815,603	
3		Total	$ 341,033,818	$ 29,692,093	$ 615,294,320	$ 4,559,759	$ 3,567,761	$994,147,751
4	Metered MWh (Excluding Shopping)	CSP	7,732,918	361,627	12,081,391	54,496	41,682	
5		OPCo	7,608,228	380,254	17,751,678	58,883	64,925	
6		Total	15,341,146	741,881	29,833,069	113,380	106,607	46,136,083
7			34.30%	2.99%	61.89%	0.46%	0.36%	
8	Class Allocation of EICC Revenue Requirement		$ 24,425,919	$ 2,126,641	$ 44,069,321	$ 326,584	$ 255,534	$ 71,204,000
9	EICC Rate ¢/kWh		0.15922	0.28666	0.14772	0.28805	0.23970	
10	Scaled EICC Rate ¢/kWh		0.15707	0.28279	0.14573	0.28416	0.23646	
11	All MWh	CSP	7,732,957	366,411	12,705,699	54,593	41,682	
12		OPCo	7,608,260	380,345	17,753,314	58,886	64,925	
13		Total	15,341,217	746,756	30,459,013	113,479	106,607	46,767,071
14	Collection		$ 24,096,450	$ 2,111,751	$ 44,387,919	$ 322,462	$ 252,083	$ 71,170,665
	Revenue Verification							$ 33,335

Line 1 - 12 Months Ending December 2010 Base Generation Revenue for Columbus Southern Power Company
Line 2 - 12 Months Ending December 2010 Base Generatioı
Line 3 - Line 1 Plus Line 2
Line 4 - Non-shopping metered MWh January - December 2010 Columbus Southern Power Company
Line 5 - Non-shopping metered MWh January - December 2010 Ohio Power Company
Line 6 - Line 4 Plus Line 5
Line 7 - Class Base Generation (Line 3) Divided by Total Base Generation
Line 8 - EICC Revenue Requirement Exhibit AEM-1 Page 1 Line 13 Times Line 7
Line 9 - Line 8 Divided by Line 6 Divided by 10
Line 10 - Line 8 Times Line 6 Total Divided by Line 13 Total
Line 11 - Total metered MWh January - December 2010 Columbus Southern Power Company
Line 12 - Total metered MWh January - December 2010 Ohio Power Company
Line 13 - Line 11 Plus Line 12
Line 14 Line 10 Times Line 13

AEP Ohio gridSMART Rider Rate*

Residential Revenue Requirement		$	4,160,503
Non-Res Revenue Requirement		$	2,233,585
Residential Customers	1,270,439	$	3.27
Non-Residential Customers	185,431	$	12.05
Residential Customers	Monthly Rate	$	0.27
Non-Residential Customers	Monthly Rate	$	1.00

* Revenue Requirement from gridSMART Rider filing as revised in Case No. 10-0164.
Ohio Power number of customers added

AEP Ohio Enhanced Service Reliability Rider Rate*

Total Revenue Requirement	$ 29,362,141
Base Distribution Revenues	$ 641,008,112
AEP Ohio ESRR	4.58062%

* Data from CSP and OPCo Schedules as revised in Case No. 10-0163

AEP Ohio Economic Development Rider Rate*

Total Revenue Requirement	$ 61,761,133
Base Distribution Revenues	$ 641,008,112
AEP Ohio ESRR	9.63500%

* Data from CSP and OPCo Schedule 1 in Case No. 10-154 & 10-1072 and Schedule 2 in Case No. 09-1095

Calculation of Energy Efficiency and Peak Demand Reduction Rider *

Tariffs	Program Costs ($)	Net Lost Distribution Revenue ($)	Shared Savings ($)	Total ($)	Allocation on Distribution Revenue ($)	Allocated Total ($)	Forecasted Metered Energy (kWh)	EE&PDR ($/kWh)
RS	67,555,061	1,577,570	734,241	69,866,872		69,866,872	24,173,461,862	0.0028902
All Other C&I					208,952,732	87,925,480	32,840,756,551	0.0026773
GS4/IRP					21,866,022	9,201,031	23,932,355,885	0.0003845
Total C&I	94,389,422	865,296	1,871,793	97,126,511	230,818,754	97,126,511	56,773,112,437	
Total	161,944,484	2,442,866	2,606,034	166,993,383		166,993,383	80,946,574,299	

* Amounts calculated based on Case Nos. 09-1089 and 09-1090

Adjustment to Universal Service Fund Rider to reflect one AEP Ohio Rate

		CSP		OPCo		AEP Ohio*
	10-99 USF Rider		0.0001830		0.0001681	0.0001731
	Exhibit DAS REV29 Filed In Case No. 10-725-EL-USF on 11/23/10 as supplemental testimony					
1	10/99 USF Rider		0.0001830		0.0001681	0.0001731
2	USF Rider Revenue Requirement	$	38,312,674.02	$	45,159,420.54	$ 83,472,094.56
3	Total kWh Used in Calculation		20,990,164,712		26,017,840,799	47,008,005,511
4	Uniform per Kwh Rate		0.0018253		0.0017357	0.0017757
5	Accounts with Annual kWh Greater than 10,000,000 kWh		118		180	298
6	Total kWh of Accounts Over 10,000,000 kWh Annually		5,753,329,672		10,872,541,304	16,625,870,976
7	First Block Annual kWh (833,334 Monthly)		10,000,000		10,000,000	10,000,000
8	Total kWh in First Block (5) x (7)		1,180,000,000		1,800,000,000	2,980,000,000
9	Revenue First Block Rate x (8)	$	2,693,661.14	$	4,635,019.14	$ 7,244,973.57
10	Total Second Block kWh (6) - (8)		4,573,329,672		9,072,541,304	13,645,870,976
11	Lower of 10/99 Rate (1) or Uniform per kWh rate		0.0001830		0.0001681	0.0001731
12	Second Block Revenue (11) x (10)	$	836,919.33	$	1,525,094.19	$ 2,362,100.27
13	Total First and Second Block Revenue (9) + (12)	$	3,530,580.47	$	6,160,113.33	$ 9,607,073.84
14	Revenue @ ODOD Proposed Rate (6) x (4)	$	10,501,552.65	$	18,871,469.94	$ 29,522,559.09
15	Revenue shortfall (13) - (14)	$	(6,970,972.18)	$	(12,711,356.61)	$ (19,915,485.25)
16	Adjusted Cost	$	34,782,094	$	38,999,307	$ 73,865,021
17	Adjusted kWh		15,236,835,040		15,145,299,495	30,382,134,535
18	Adjusted First Block Rate		0.0022828		0.0025750	0.0024312

* Weighted CSP and OPCo 1999 Rates based on line 10

AEP Ohio Proposed Distribution Investment Rider

Line		CSP	OPCo	AEP Ohio
1	2000 Distribution Net Plant			
2	Distribution Plant - Form 1 Page 207 Line 69	$ 1,094,289,026	$ 1,040,916,689	$ 2,135,205,715
3	Accumulated Depreciation - Form 1 Page 219 Line 24	$ 451,885,982	$ 309,699,840	$ 761,585,822
4=2-3	Net Distribution Plant	$ 642,403,044	$ 731,216,849	$ 1,373,619,893
5				
6	2011 Distribution Net Plant			
7	Distribution Plant - Form 1 Page 207 Line XX	TBD	TBD	TBD
8	Accumulated Depreciation - Form 1 Page 219 Line XX	TBD	TBD	TBD
9=7-8	Net Distribution Plant			
10				
11=9-4	Change in Distribution Net Plant			
12				
13	Solar Panel Net Plant Adjustment (Recovered through FAC)			
14				
15	gridSMART Net Plant Adjustment (Recovered through GS Rider)			
16				
17=11-13-15	Adjusted Distribution Net Plant			
18				
19	Carrying Charge Rate (Grossed up WACC Plus 3.5% O&M Adder)			15.10%
20				
21=17*19	Rider Revenue			
22				
23	2006 Distribution Increase Case Nos. 05-842 & 05-843	$ 7,976,901	$ 11,907,391	$ 19,884,292
24				
25=21-23	Revised Rider Revenue			
26				
27	Capital Revenue Requirement for Veg Mgmt			
28				
29=25-27	Fully Adjusted Rider Revenue			
30				
31	Annual Base Distribution Revenue			
32				
33=29/31	AEP Ohio Percentage of Base Distribution Rate			%

Exhibit AEM-4
Page 1 of 1

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY
OF
DAVID M. ROUSH
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: January 27, 2011

INDEX TO DIRECT TESTIMONY OF
DAVID M. ROUSH

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
DAVID M. ROUSH
ON BEHALF OF
COLUMBUS SOUTHERN POWER
AND
OHIO POWER COMPANY

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Director - Regulated Pricing and Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo), referred to collectively as AEP Ohio or the Company.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from The Ohio State University (OSU) in 1989 with a Bachelor of Science degree in mathematics with a computer and information science minor. In 1999, I earned a Master of Business Administration degree from The University of Dayton. I have completed both the EEI Electric Rate Fundamentals and Advanced Courses. In 2003, I completed the AEP/OSU Strategic Leadership Program.

In 1989, I joined AEPSC as a Rate Assistant. Since that time I have progressed through various positions and was promoted to my current position of Director – Regulated Pricing and Analysis in June 2010. My responsibilities include the oversight of the preparation of cost-of-service and rate design analyses for the AEP System operating companies, and oversight of the preparation of special contracts and pricing for customers.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before the Public Utilities Commission of Ohio (Commission), the Indiana Utility Regulatory Commission, the Michigan Public Service Commission, the Public Service Commission of Kentucky and the Public Service Commission of West Virginia regarding cost-of-service, rate design and other rates and tariff related issues.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss certain features of AEP Ohio's Electric Security Plan (ESP) filing pursuant to Am. Sub S. B. No. 221 (S.B. 221). Specifically, I summarize AEP Ohio's requested rate relief as supported by a number of the Company witnesses, describe the required modifications to the Company's Tariffs and Terms and Conditions of Service, explain the design of the Company's proposed rates and certain riders, and provide the resulting rate impacts on CSP and OPCo customers.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following exhibits:

Exhibit DMR-1	Summary of Requested Rate Increase
Exhibit DMR-2	Calculation of Standard Offer Generation Service Rider
Exhibit DMR-3	Market Transition Rider
Exhibit DMR-4	Summary of ESP Rate Mechanisms
Exhibit DMR-5	Redlined CSP Tariffs (provided in separate volume)
Exhibit DMR-6	Redlined OPCo Tariffs (provided in separate volume)
Exhibit DMR-7	Typical Bills

REQUESTED RATE RELIEF

Q. HAVE YOU PREPARED A SUMMARY OF AEP OHIO'S REQUESTED RATE INCREASES UNDER THE ELECTRIC SECURITY PLAN?

A. Yes. Exhibit DMR-1 summarizes each component of AEP Ohio's request based upon the information provided to me by Company witnesses. Exhibit DMR-1 shows the proposed annual change in base generation rates and the decrease in Provider of Last Resort (POLR) charges. Exhibit DMR-1 does not show any estimate of the potential changes in costs recovered through the FAC and the Environmental Investment Carrying Cost Rider (EICCR), nor any estimate of future changes in the level of the existing Transmission Cost Recovery Rider (TCRR), base distribution rates and distribution-related riders. Each of these components of the ESP will be discussed later in my testimony.

MODIFICATIONS TO THE TARIFFS, TERMS AND CONDITIONS OF SERVICE

Q. IS AEP OHIO PROPOSING CHANGES TO THE TERMS AND CONDITIONS OF SERVICE?

A. AEP Ohio is maintaining the current provisions concerning the process by which customers can switch to a Competitive Retail Electric Service (CRES) provider and return from a CRES provider to the standard offer service. This includes continuing its existing Commission-approved switching rules, switching charges and minimum stay provisions. Company witness Thomas discusses specific provisions regarding the ability of customers to relinquish their ability to return to standard offer service and avoid the otherwise nonbypassable POLR charges.

Q. HOW DID AEP OHIO ADJUST THE POLR CHARGE RIDER?

A. Based upon the proposed level of POLR costs as provided to me by Company witness Thomas, the proposed POLR charge is a uniform per kWh charge.

Q. IS AEP OHIO PROPOSING ANY CHANGES TO THE TCRR?

A. No. The TCRR will continue to operate as it currently does. AEP Ohio submits annual update and reconciliation filings in mid-April of each year as required pursuant to Case No. 08-777-EL-ORD. The April 2011 filing will present rates for the merged Company in addition to the rates for CSP and OPCo.

Q. PLEASE EXPLAIN AEP OHIO'S CHANGES TO ITS STANDARD SERVICE OFFER TARIFFS.

A. In this case, AEP Ohio is proposing to remove all base generation charges from its Standard Service Offer tariffs and relocate the charges to a single Standard Offer Generation Service Rider (GSR). The GSR includes the same rates and charges for CSP and OPCo customers consistent with the pending merger of the

Companies. This Rider will apply to all customers that are not receiving service from CRES providers, except those customers that have elected to not pay POLR charges and have returned at market-based rates.

Q. PLEASE EXPLAIN AEP OHIO'S CHANGES TO ITS INTERRUPTIBLE SERVICE OFFERINGS.

A. In this case, AEP Ohio is proposing to restructure its existing interruptible service offerings. In today's environment, interruptible service is more typically represented as an offset or modifier to firm service rates rather than as a separate and distinct rate. As such, AEP Ohio is proposing to entirely replace Schedule Interruptible Power – Discretionary (IRP-D), Rider Emergency Curtailable Service (ECS) and eliminate Rider Price Curtailable Service (PCS). Rider IRP-D and the new Rider ECS offer customers the opportunity to select the combination of interruptible services which best fit their needs. These offerings are intrinsically linked to AEP Ohio's obligations under the Fixed Resource Requirement alternative under the Reliability Assurance Agreement of PJM Interconnection, LLC. Therefore, AEP Ohio's proposed compensation to customers for being willing to interrupt is based upon the same capacity rates charged to CRES providers for their use of the Company's capacity resources. This proposed credit rate will be updated periodically to reflect changes in that rate.

For customers taking service under Schedule IRP-D as of December 2011, a modified Rider IRP-D will be made available to them or such customers may elect to take service under proposed Rider ECS. No new customers will be permitted to enroll in Rider IRP-D.

Q. ARE THERE ANY OTHER ISSUES RELATED TO INTERRUPTIBLE SERVICE?

A. Yes. On March 19, 2010, in Case Nos. 10-343-EL-ATA and 10-344-EL-ATA, AEP Ohio has pending before the Commission proposed changes to Rider ECS. AEP Ohio has included that proposed Rider ECS in this filing adjusted to reflect the capacity rate described above.

Q. HOW DO THESE CHANGES AFFECT INTERRUPTIBLE CUSTOMERS?

A. These changes have the potential to be beneficial to interruptible customers, as the compensation for being willing to interrupt would be based upon the outcome of the issues pending in Case No. 10-2929-EL-UNC. Further, the changes bring AEP Ohio's interruptible service offerings into better alignment with the PJM wholesale program.

Q. ARE THERE OTHER CHANGES THAT AEP OHIO IS PROPOSING IN ITS TARIFFS?

A. Yes. AEP Ohio is proposing two voluntary options for customers. The first is the option to purchase a higher percentage of usage from renewable resources. The second option provides the customer with greater certainty regarding base generation prices during the three-year period following the term of this ESP.

Q. PLEASE DESCRIBE THE VOLUNTARY RENEWABLE RESOURCE OPTION.

A. AEP Ohio is proposing a voluntary option for customers that wish to purchase a larger proportion of their electricity from renewable resources than the levels required under S.B. 221. The Green Power Portfolio Rider (GPPR) gives customers the option to purchase 25%, 50%, 75% or 100% of their energy usage from renewable resources. Customers that elect this option would be exempt from the Alternative Energy Rider (AER). All amounts collected under the GPPR would offset the costs paid by all other customers through the AER. Pricing for the GPPR will be updated no more frequently than once a year based upon the difference in cost of renewable resources.

Q. PLEASE DESCRIBE THE RATE SECURITY RIDER (RSR).

A. As discussed by Company witness Hamrock, AEP Ohio is proposing a voluntary option for customers that are willing to commit to SSO service from AEP Ohio for the period January 2012 through May 2017. This option is available to certain commercial and industrial customers having annual peak demands of greater than 200 kW and is limited to aggregate annual usage of 2,500 GWh. To enroll in this option, customers must commit to AEP Ohio during November 2011 through March 2012. Requests will be honored in the order they are received. Upon making such an election, the Company would enter into a standardized agreement with that customer and that customer would be eligible to receive the discount that would be administered through the RSR.

Under this option, customers will continue to pay all rates, charges and riders of the applicable SSO rate schedule. During the term of the ESP, the customer will receive a 15% discount on their base generation rate billing under the Standard Offer Generation Service Rider. For June 2014 through May 2015, base generation rate billing for customers electing this option will be at a 10% discount from the May 2014 base generation rates. For June 2015 through May 2016, base generation rate billing for customers electing this option will be at a 5% discount from the May 2014 base generation rates. For June 2016 through May 2017, base generation rate billing for customers electing this option will be at no discount from the May 2014 base generation rates. The following table summarizes the rate provisions of this option:

Period	Base Generation Rate	Base Generation Discount	All Other Charges
January 2012 through December 2012	2012 SSO Rate	15%	SSO Rate Schedule & Riders
January 2013 through May 2014	2013/2014 SSO Rate	15%	SSO Rate Schedule & Riders
June 2014 through May 2015	May 2014 SSO Rate	10%	SSO Rate Schedule & Riders
June 2015 through May 2016	May 2014 SSO Rate	5%	SSO Rate Schedule & Riders
June 2016 through May 2017	May 2014 SSO Rate	0%	SSO Rate Schedule & Riders

<u>DESIGN OF THE PROPOSED RATES AND RIDERS</u>

Q. HOW WERE AEP OHIO'S PROPOSED BASE GENERATION RATES AS SHOWN IN THE STANDARD OFFER GENERATION SERVICE RIDER DESIGNED?

A. The first step in the design of the proposed base generation rates was to determine the market-based price relationship for the various types of customer usage. This was accomplished by applying the methodology used by Company witness Thomas to develop the competitive benchmark price to the specific customer class load shapes. Once this relationship was determined, the proposed total generation rates were designed to maintain these relationships and produce AEP Ohio's requested average generation price.

The next step in the design of the proposed base generation rates was to deduct the projected 2011 full costs for both the Fuel Adjustment Clause (FAC) and Environmental Investment Carrying Cost Rider (EICCR) to arrive at the 2012 base generation rates. The base generation rates for January 2013 to May 2014 were calculated by uniformly increasing the 2012 base generation rates to achieve AEP Ohio's proposed average generation price. These calculations are shown in Exhibit DMR-2.

It is important to note that only the relative market price relationships are used in developing the proposed rates. In other words, it is the pricing relationships that are being established in this manner, not the overall level of the price.

Q. WHY DID AEP OHIO DESIGN GENERATION RATES BASED UPON MARKET PRICE RELATIONSHIPS?

A. CSP and OPCo's last rate cases were in the early 1990's. Since that time the Company's rates have been unbundled into generation, transmission and distribution components and subsequently adjusted based upon percentage adjustments to the then current unbundled rates. As such, the generation rates reflect an amalgamation of very old cost relationships, including any historical levels of cross-subsidization among tariff classes. In addition, CSP and OPCo are proposing a merger and the post-merger Company is what is reflected in the proposed ESP rates. For these reasons, AEP Ohio's proposal in this proceeding is to rationalize the rate relationships based upon the manner in which the market would price such loads using the same methodology used by Company witness Thomas to develop the competitive benchmark price and applying it to the class load shapes. This realignment of rates with market should provide all customers with equivalent opportunities to shop. Further, since the design eliminates explicit demand charges, it should make it easier for customers to evaluate competitive offers.

Q. BASED UPON THE PROPOSED BASE GENERATION RATES, DID YOU PREPARE MARKET COMPARABLE GENERATION PRICES FOR COMPANY WITNESS THOMAS?

A. Yes. I provided Company witness Thomas with proposed ESP generation prices that are comparable to market generation prices for the comparison of AEP Ohio's ESP to an MRO. To prepare these values, I added the proposed base generation prices, 2011 full cost FAC and EICCR. Finally, I adjusted the ESP generation prices to reflect the fact that certain generation costs included in AEP Ohio's TCRR must be included to be comparable to the market generation prices used by Company witness Thomas.

Q. IS AEP OHIO PROPOSING TO IMPLEMENT ANY NEW RIDERS?

A. Yes. I am supporting AEP Ohio's proposal to implement a Generation Resource Rider (GRR) and a Market Transition Rider (MTR).

As discussed by Company witness Nelson, the GRR is a nonbypassable rider designed to collect the costs associated with AEP Ohio investment in generating facilities in accordance with Section 4928.143 (B) (2) (c). Since AEP Ohio has no such costs at this time, the rider is simply a placeholder until such time as the Commission approves costs to be recovered. The Turning Point Solar Project, as discussed by Company witnesses Godfrey and Nelson, is anticipated to be the first project included in the GRR.

The MTR is designed to facilitate the transition from CSP and OPCo's current generation rates to the market-based SSO Generation Service rates discussed above. The MTR is a nonbypassable rider designed to limit the first and second year changes for any customer classes to uniformly transition any above or below average changes in three steps. Any revenue shortfall that is produced by limiting the increases for certain customer classes is collected from those classes whose decreases are limited.

On an annual basis, the sum of the credits provided and charges collected under the MTR should be zero (0). However, since actual customer usage by customer class will vary, the net of actual credits and charges could be greater than or less than zero (0). Since the intent of the MTR is to facilitate the rebalancing of rates in a revenue neutral fashion and thus neither to increase nor to decrease AEP Ohio's revenues, the Company proposes to include over- or under-recoveries in the quarterly FAC reconciliation. At the beginning of 2013, both the credits and the charges under the MTR would be reduced by approximately one-half. At the beginning of 2014, all credits and charges under the MTR would end. In this manner, the rate rebalancing would be complete by the end of the ESP and AEP Ohio's rates would better reflect today's competitive market pricing structures. The credits and charges for each year are shown in Exhibit DMR-3.

Q. PLEASE SUMMARIZE THE RATE MECHANISMS PROPOSED IN THE AEP OHIO'S ESP.

A. Exhibit DMR-4 is a comprehensive schedule of the proposed ESP rate mechanisms that are sponsored by various Company witnesses in this proceeding.

<u>IMPLEMENTATION AND CUSTOMER BILL IMPACTS</u>

Q. WHEN WILL AEP OHIO FILE AND IMPLEMENT THE PROPOSED ESP RATES?

A. Upon approval of the proposed ESP by the Commission, AEP Ohio will file compliance tariffs to be effective for bills rendered beginning with the first billing cycle of January 2012. For January 2012, the first billing cycle is December 30, 2011. A redline of the complete tariffs are provided in Exhibit DMR-5 for CSP and Exhibit DMR-6 for OPCo.

Q. WHAT HAPPENS IF THE PROPOSED ESP IS NOT APPROVED PRIOR TO DECEMBER 30, 2011?

A. Ideally, the tariff changes will be filed after the Commission issues a final order approving the ESP without modification in this proceeding. Should that approval not be received by December 30, 2011, AEP Ohio proposes that CSP and OPCo continue billing under the current ESP base generation rates, and that the FAC and EICCR continue to operate and adjust without any "cap". This approach is more straightforward than implementing the ESP rates and subsequently reconciling to the Commission's final order. Once a final order in this proceeding is issued, a one-time rider would be implemented in conjunction with the ultimately approved ESP rates. This one-time rider would be designed to prospectively collect the difference between the approved ESP rates and the actual rates charged to customers during the period between the end of the December 2011 billing month and the effective date of the approved ESP rates. This one-time rider would be designed to collect such amounts over the remainder of the 2012 billing months, with a true-up, if necessary, in the first quarter of 2013.

Q. WHAT HAPPENS IF THE ESP IS APPROVED BUT THE PROPOSED MERGER OF CSP AND OPCO IS NOT CLOSED?

A. If the merger is not closed by December 31, 2011, AEP Ohio proposes to apply the proposed ESP base generation rates for both CSP and OPCo. The FAC and EICCR Riders would continue to operate separately for CSP and OPCo and the MTR would not apply because the MTR was designed to provide a transition to market-based SSO generation rates for the merged Company. However, if the merger is not closed by June 30, 2012 AEP Ohio will file appropriate amendments to provide separate rate plans for each of the Companies.

Q. WHAT IMPACT WILL AEP OHIO'S ESP HAVE ON CUSTOMER BILLS?

A. Upon implementation, residential customers using 1,000 kWh of electricity per month would see a monthly rate increase of $1.83 for CSP and $5.50 for OPCo in 2012. Exhibit DMR-7 shows the percentage increases at various "typical" usage levels for each major tariff schedules.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

AEP Ohio
Summary of ESP Generation Rate Increases

Customer Class	Unmitigated 2012 Increase	Market Transition Plan 2012 Increase	2013 Increase	2014 Increase	Total Increase
RS	7.2%	5.0%	3.9%	1.0%	10.2%
GS1	(20.0%)	(6.4%)	(5.2%)	(7.8%)	(18.1%)
GS2	(20.0%)	(5.3%)	(5.5%)	(8.2%)	(17.8%)
GS3	(3.7%)	(0.3%)	1.0%	(1.8%)	(1.2%)
GS4/IRP	12.2%	2.3%	7.7%	4.7%	15.3%
AL	(13.9%)	0.2%	(5.9%)	(8.6%)	(13.9%)
SL	(13.1%)	(0.7%)	(5.1%)	(7.8%)	(13.1%)
SBS	3.3%	1.4%	4.3%	1.4%	7.2%
Total CSP	2.2%	2.2%	2.7%	0.0%	5.0%
RS	6.6%	6.0%	3.1%	0.3%	9.7%
GS1	(9.8%)	1.5%	(3.3%)	(6.1%)	(7.8%)
GS2	(6.8%)	0.1%	(0.7%)	(3.5%)	(4.1%)
GS3	(0.6%)	(0.7%)	2.8%	(0.0%)	2.0%
GS4/IRP	(0.8%)	(6.6%)	5.8%	3.0%	1.7%
EHG	10.0%	5.1%	5.0%	2.2%	12.8%
EHS	44.0%	3.9%	21.2%	18.2%	48.8%
SS	(0.4%)	1.1%	2.0%	(0.7%)	2.4%
FL	22.7%	7.2%	9.7%	6.9%	25.7%
OL	(32.4%)	(3.5%)	(14.9%)	(17.6%)	(32.4%)
SL	(38.5%)	(8.1%)	(16.9%)	(19.5%)	(38.5%)
SBS	45.5%	21.6%	14.2%	11.3%	54.7%
Total OP	0.4%	0.4%	2.7%	0.0%	3.1%
AEP Ohio	1.4%	1.4%	2.7%	0.0%	4.2%

AEP Ohio

Summary of ESP Rate Increases with Market Transition Rider

2012 Rates before ESP*

	Total Gen.	Current Trans.	Current Dist.	POLR	Phase-In Rider	Total
CSP						
RS	5.77	0.82	4.00	0.57		**11.16**
GS1	8.47	0.70	3.63	0.49		**13.29**
GS2	8.29	0.75	2.41	0.50		**11.95**
GS3	5.92	0.58	1.59	0.39		**8.48**
GS4/IRP	4.45	0.70	0.28	0.33		**5.76**
AL	6.70	0.22	13.66	0.16		**20.75**
SL	5.55	0.22	7.38	0.19		**13.34**
SBS	6.40	1.72	0.34	0.40		**8.87**
Subtotal	5.73	0.72	2.46	0.46		**9.37**
OP						
RS	5.66	0.65	3.41	0.23	0.52	**10.67**
GS1	6.70	0.70	4.04	0.26	0.52	**12.22**
GS2	6.29	0.60	2.10	0.27	0.52	**9.78**
GS3	5.21	0.59	1.49	0.19	0.51	**7.99**
GS4/IRP	4.57	0.56	0.25	0.16	0.49	**6.03**
EHG	4.71	1.03	2.81	0.29	0.52	**9.36**
EHS	3.16	0.65	0.81	0.37	0.52	**5.52**
SS	5.71	0.65	2.15	0.29	0.52	**9.33**
FL	3.60	0.60	2.71	0.27	0.52	**7.70**
OL	10.32	0.27	10.19	0.06	0.52	**21.36**
SL	10.79	0.27	7.51	0.06	0.52	**19.16**
SBS	50.32	19.77	41.27	0.19	0.49	**112.04**
Subtotal	5.31	0.65	1.77	0.20	0.51	**8.45**
AEP Ohio	**6.48**	**0.68**	**2.05**	**0.31**	**0.28**	**8.80**
Percentage Increase						

2012 Rates with ESP

	Total Gen.	Current Trans.	Current Dist.	POLR	Phase-In Rider	Transition Rider	Total
CSP							
RS	6.57	0.82	4.00	0.28	0.29	(0.245)	**11.72**
GS1	5.73	0.70	3.63	0.28	0.29	1.811	**12.44**
GS2	5.83	0.75	2.41	0.28	0.29	1.753	**11.32**
GS3	5.42	0.58	1.59	0.28	0.29	0.291	**8.46**
GS4/IRP	4.92	0.70	0.28	0.28	0.27	(0.567)	**5.89**
AL	3.41	0.22	13.66	0.28	0.29	2.913	**20.78**
SL	3.42	0.22	7.38	0.28	0.29	1.657	**13.25**
SBS	6.53	1.72	0.34	0.28	0.27	(0.163)	**8.99**
Subtotal	5.83	0.72	2.46	0.28	0.28	(0.000)	**9.58**
OP							
RS	6.54	0.85	3.41	0.28	0.29	(0.058)	**11.32**
GS1	5.71	0.70	4.04	0.28	0.29	1.380	**12.41**
GS2	5.84	0.60	2.10	0.28	0.29	0.671	**9.78**
GS3	5.30	0.59	1.49	0.28	0.28	(0.006)	**7.94**
GS4/IRP	4.61	0.56	0.25	0.28	0.27	(0.352)	**5.63**
EHG	5.88	1.03	2.81	0.28	0.29	(0.459)	**9.84**
EHS	5.92	0.65	0.81	0.28	0.29	(2.215)	**5.74**
SS	5.92	0.65	2.15	0.28	0.29	0.145	**9.44**
FL	5.57	0.60	2.71	0.28	0.29	(1.192)	**8.26**
OL	3.41	0.27	10.19	0.28	0.29	6.166	**20.61**
SL	3.42	0.27	7.51	0.28	0.29	5.828	**17.60**
SBS	101.40	19.77	41.27	0.28	0.27	(26.719)	**136.28**
Subtotal	5.49	0.65	1.77	0.28	0.28	(0.000)	**8.49**
AEP Ohio	**5.63**	**0.68**	**2.05**	**0.28**	**0.28**	**(0.00)**	**8.93**
Percentage Increase							**1.46%**

2013 Rates

	Total Gen.	Current Trans.	Current Dist.	POLR	Phase-In Rider	Transition Rider	Total
CSP							
RS	6.91	0.82	4.00	0.28	0.29	(0.124)	**12.18**
GS1	5.98	0.70	3.63	0.28	0.29	0.923	**11.80**
GS2	6.09	0.75	2.41	0.28	0.29	0.873	**10.69**
GS3	5.64	0.58	1.59	0.28	0.29	0.155	**8.54**
GS4/IRP	5.11	0.70	0.28	0.28	0.27	(0.297)	**6.34**
AL	3.42	0.22	13.66	0.28	0.29	1.675	**19.55**
SL	3.42	0.22	7.38	0.28	0.29	0.976	**12.57**
SBS	6.89	1.72	0.34	0.28	0.27	(0.131)	**9.38**
Subtotal	6.09	0.72	2.46	0.28	0.28	(0.000)	**9.84**
OP							
RS	6.87	0.85	3.41	0.28	0.29	(0.037)	**11.67**
GS1	5.96	0.70	4.04	0.28	0.29	0.726	**12.00**
GS2	6.10	0.60	2.10	0.28	0.29	0.339	**9.71**
GS3	5.51	0.59	1.49	0.28	0.28	0.003	**8.16**
GS4/IRP	4.76	0.56	0.25	0.28	0.27	(0.176)	**5.96**
EHG	6.15	1.03	2.81	0.28	0.29	(0.228)	**10.33**
EHS	6.18	0.65	0.81	0.28	0.29	(1.267)	**6.95**
SS	6.18	0.65	2.15	0.28	0.29	0.072	**9.63**
FL	5.80	0.60	2.71	0.28	0.29	(0.621)	**9.06**
OL	3.42	0.27	10.19	0.28	0.29	3.084	**17.53**
SL	3.42	0.27	7.51	0.28	0.29	2.855	**14.64**
SBS	111.71	19.77	41.27	0.28	0.27	(17.655)	**155.65**
Subtotal	5.72	0.65	1.77	0.28	0.28	(0.000)	**8.72**
AEP Ohio	**5.87**	**0.68**	**2.05**	**0.28**	**0.28**	**(0.00)**	**9.17**
Percentage Increase							**2.72%**

January - May 2014 Rates

	Total Gen.	Current Trans.	Current Dist.	POLR	Phase-In Rider	Total
CSP						
RS	6.91	0.82	4.00	0.28	0.29	**12.30**
GS1	5.98	0.70	3.63	0.28	0.29	**10.88**
GS2	6.09	0.75	2.41	0.28	0.29	**9.82**
GS3	5.64	0.58	1.59	0.28	0.29	**8.38**
GS4/IRP	5.11	0.70	0.28	0.28	0.27	**6.64**
AL	3.42	0.22	13.66	0.28	0.29	**17.88**
SL	3.42	0.22	7.38	0.28	0.29	**11.60**
SBS	6.89	1.72	0.34	0.28	0.27	**9.51**
Subtotal	6.09	0.72	2.46	0.28	0.28	**9.84**
OP						
RS	6.87	0.85	3.41	0.28	0.29	**11.71**
GS1	5.96	0.70	4.04	0.28	0.29	**11.27**
GS2	6.10	0.60	2.10	0.28	0.29	**9.37**
GS3	5.51	0.59	1.49	0.28	0.28	**8.15**
GS4/IRP	4.76	0.56	0.25	0.28	0.27	**6.13**
EHG	6.15	1.03	2.81	0.28	0.29	**10.56**
EHS	6.18	0.65	0.81	0.28	0.29	**8.22**
SS	6.18	0.65	2.15	0.28	0.29	**9.56**
FL	5.80	0.60	2.71	0.28	0.29	**9.68**
OL	3.42	0.27	10.19	0.28	0.29	**14.45**
SL	3.42	0.27	7.51	0.28	0.29	**11.78**
SBS	111.71	19.77	41.27	0.28	0.27	**173.31**
Subtotal	5.72	0.65	1.77	0.28	0.28	**8.72**
AEP Ohio	**5.87**	**0.68**	**2.05**	**0.28**	**0.28**	**9.17**
Percentage Increase						**0.00%**

*Note: Reflects full cost 2011 FAC and Environmental Investment Carrying Cost Rider and implementation of Phase-In Rider

Calculation of Standard Offer
Generation Service Rider

AEP Ohio			All Hours			On-Peak Hours			Off-Peak Hours		
			Annual	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter
Scalars			1.00	1.07	0.96	1.15	1.28	1.08	0.83	0.83	0.84
Market Shaped Rates											
Residential			90.25	96.71	86.67	103.89	115.38	97.04	75.19	74.77	75.41
GS-1			79.64	85.34	76.39	91.68	101.81	85.63	68.34	65.98	66.54
AL			48.92	52.42	46.92	56.31	62.53	52.60	40.75	40.53	40.87
SL			49.05	52.56	47.05	56.46	62.70	52.74	40.86	40.64	40.98
Demand Metered	LF	All kWh Price									
First 100 kWh/kW	14%	84.43	84.43	90.47	80.99	97.19	107.93	90.78	70.33	69.95	70.54
100 - 200 kWh/kW	27%	83.86	83.29	89.25	79.89	95.86	106.47	89.55	69.38	69.00	69.59
200 - 300 kWh/kW	41%	82.23	78.96	84.61	75.74	90.89	100.93	84.90	65.77	65.41	65.97
300 - 400 kWh/kW	55%	79.53	71.44	76.55	68.52	82.23	91.32	76.81	59.51	59.18	59.69
400 - 500 kWh/kW	68%	75.77	60.72	65.07	58.25	69.90	77.63	65.29	50.59	50.31	50.74
500 - 600 kWh/kW	82%	70.94	46.82	50.17	44.91	53.90	59.86	50.35	39.01	38.79	39.12
Over 600 kWh/kW	96%	65.06	29.73	31.86	28.52	34.23	38.01	31.97	24.77	24.63	24.84
Transmission Adjustment											
Residential			-2.2055								
GS-1			-2.6681								
AL			-2.4898								
SL			-2.5388								
Demand Metered			-2.1251								
Market Shaped Rates Adjusted for Transmission											
Residential			88.05	94.51	84.37	101.69	113.17	94.84	72.98	72.57	73.20
GS-1			76.97	82.67	73.73	89.01	99.14	82.96	63.68	63.31	63.88
AL			46.43	49.93	44.43	53.82	60.04	50.11	38.26	38.04	38.38
SL			46.51	50.02	44.51	53.92	60.16	50.20	38.32	38.10	38.44
Demand Metered											
First 100 kWh/kW			82.31	88.35	78.86	95.07	105.81	88.66	66.21	67.82	68.42
100 - 200 kWh/kW			81.16	87.12	77.77	93.75	104.35	87.43	67.26	66.86	67.46
200 - 300 kWh/kW			76.83	82.48	73.61	88.77	98.61	82.77	63.65	63.29	63.85
300 - 400 kWh/kW			69.31	74.42	66.40	80.11	89.19	74.68	57.39	57.06	57.56
400 - 500 kWh/kW			58.60	62.94	56.12	67.78	75.50	63.17	48.46	48.18	48.61
500 - 600 kWh/kW			44.70	48.05	42.79	51.77	57.73	48.22	36.88	36.67	37.00
Over 600 kWh/kW			27.61	29.73	26.39	32.10	35.86	29.84	22.64	22.51	22.72
Ratio to Meet Proposed Increase											
Current Base G Revenues			914,297,802								
Proposed Base G Increase			65,255,250								
Target 2012 Base G Revenues			979,553,052			**2011 Full Environmental Revenues**			39,196,016		
Base G Revenues Produced			979,526,334			**Proposed Environmental Revenues**			39,195,942		
Difference			26,718	**76%**		**Difference**			74		**4.00152%**
Second Year Increase %			**10.77729%**								
Tariff Total Generation Rates (1st Year)											
Residential			$0.0673335	$0.0722719	$0.0645188	$0.0777656	$0.0865457	$0.0725256	$0.0568109	$0.0554943	$0.0559816
GS-1			$0.0588646	$0.0632222	$0.0563809	$0.0680699	$0.0758175	$0.0634462	$0.0486966	$0.0484177	$0.0488477
AL			$0.0355038	$0.0381803	$0.0339783	$0.0411579	$0.0459168	$0.0383179	$0.0292585	$0.0290872	$0.0293513
SL			$0.0355684	$0.0382522	$0.0340388	$0.0412379	$0.0460095	$0.0383902	$0.0293061	$0.0291343	$0.0293991
Demand Metered											
First 100 kWh/kW			$0.0629421	$0.0675618	$0.0603089	$0.0727011	$0.0809148	$0.0677992	$0.0521824	$0.0518667	$0.0523225
100 - 200 kWh/kW			$0.0620687	$0.0666259	$0.0594712	$0.0716957	$0.0797983	$0.0668601	$0.0514349	$0.0511431	$0.0515926
200 - 300 kWh/kW			$0.0587560	$0.0630762	$0.0562936	$0.0678824	$0.0755635	$0.0632982	$0.0486762	$0.0483986	$0.0488260
300 - 400 kWh/kW			$0.0530040	$0.0569127	$0.0507762	$0.0612610	$0.0682104	$0.0571136	$0.0438836	$0.0436333	$0.0440190
400 - 500 kWh/kW			$0.0448127	$0.0481353	$0.0429189	$0.0518316	$0.0577390	$0.0483061	$0.0370598	$0.0368471	$0.0371750
500 - 600 kWh/kW			$0.0341822	$0.0367442	$0.0327219	$0.0395943	$0.0441494	$0.0368758	$0.0282041	$0.0280400	$0.0282929
Over 600 kWh/kW			$0.0211123	$0.0227391	$0.0201850	$0.0245490	$0.0274414	$0.0228227	$0.0173162	$0.0172121	$0.0173726
Less: Fuel			$0.0335561								
Less: Environmental			4.00152%								

Calculation of Standard Offer Generation Service Rider

	All Hours			On-Peak Hours			Off-Peak Hours		
2012 Base Generation Rates	Annual	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter
Residential		$0.03582	$0.02838		$0.04953	$0.03607		$0.01972	$0.02019
GS-1		$0.02714	$0.02057		$0.03923	$0.02735		$0.01292	$0.01334
AL	$0.00053								
SL	$0.00059								
Demand Metered - Secondary									
First 100 kWh/kW		$0.03130	$0.02434						
100 - 200 kWh/kW		$0.03040	$0.02354						
200 - 300 kWh/kW		$0.02700	$0.02048						
300 - 400 kWh/kW		$0.02108	$0.01519						
400 - 500 kWh/kW		$0.01265	$0.00765						
500 - 600 kWh/kW		$0.00172	$0.00000						
Over 600 kWh/kW		$0.00000	$0.00000						
Losses:	0.9653092								
Demand Metered - Primary									
First 100 kWh/kW		$0.03021	$0.02350						
100 - 200 kWh/kW		$0.02935	$0.02272						
200 - 300 kWh/kW		$0.02606	$0.01977						
300 - 400 kWh/kW		$0.02035	$0.01466						
400 - 500 kWh/kW		$0.01221	$0.00738						
500 - 600 kWh/kW		$0.00166	$0.00000						
Over 600 kWh/kW		$0.00000	$0.00000						
Losses:	0.9460784								
Demand Metered - Subtransmission/Transmission									
First 100 kWh/kW		$0.02961	$0.02303						
100 - 200 kWh/kW		$0.02876	$0.02227						
200 - 300 kWh/kW		$0.02554	$0.01938						
300 - 400 kWh/kW		$0.01994	$0.01437						
400 - 500 kWh/kW		$0.01197	$0.00724						
500 - 600 kWh/kW		$0.00163	$0.00000						
Over 600 kWh/kW		$0.00000	$0.00000						

	All Hours			On-Peak Hours			Off-Peak Hours		
2013 Base Generation Rates	Annual	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter
Residential		$0.03868	$0.03144		$0.05487	$0.03996		$0.02185	$0.02237
GS-1		$0.03008	$0.02279		$0.04346	$0.03030		$0.01431	$0.01478
AL	$0.00059								
SL	$0.00065								
Demand Metered - Secondary									
First 100 kWh/kW		$0.03467	$0.02696						
100 - 200 kWh/kW		$0.03368	$0.02608						
200 - 300 kWh/kW		$0.02991	$0.02269						
300 - 400 kWh/kW		$0.02335	$0.01683						
400 - 500 kWh/kW		$0.01401	$0.00847						
500 - 600 kWh/kW		$0.00191	$0.00000						
Over 600 kWh/kW		$0.00000	$0.00000						
Demand Metered - Primary									
First 100 kWh/kW		$0.03347	$0.02603						
100 - 200 kWh/kW		$0.03251	$0.02517						
200 - 300 kWh/kW		$0.02887	$0.02190						
300 - 400 kWh/kW		$0.02254	$0.01624						
400 - 500 kWh/kW		$0.01353	$0.00818						
500 - 600 kWh/kW		$0.00184	$0.00000						
Over 600 kWh/kW		$0.00000	$0.00000						
Demand Metered - Subtransmission/Transmission									
First 100 kWh/kW		$0.03280	$0.02551						
100 - 200 kWh/kW		$0.03186	$0.02467						
200 - 300 kWh/kW		$0.02829	$0.02147						
300 - 400 kWh/kW		$0.02209	$0.01592						
400 - 500 kWh/kW		$0.01326	$0.00802						
500 - 600 kWh/kW		$0.00181	$0.00000						
Over 600 kWh/kW		$0.00000	$0.00000						

Exhibit DMR-3

Market Transition Rider

Line No.	Company	Class/ Descript. (A)	2012 Transition Rider (B)	2013 Transition Rider (C)
1	CSP	Residential Service	($0.00245)	($0.00124)
2				
3	CSP	General Service - Small	$0.01811	$0.00923
4				
5	CSP	General Service - Low Load Factor	$0.01753	$0.00873
6				
7	CSP	General Service - Medium Load Factor	$0.00291	$0.00155
8				
9	CSP	General Service - Large / Interruptible Power - Discretionary	($0.00567)	($0.00297)
10				
11	CSP	Area Lighting	$0.02913	$0.01675
12				
13	CSP	Street Lighting	$0.01657	$0.00976
14				
15	CSP	Standby Service	($0.00163)	($0.00131)
16				
17	OPCo	Residential Service	($0.00058)	($0.00037)
18				
19	OPCo	General Service - Non-Demand Metered	$0.01380	$0.00726
20				
21	OPCo	General Service - Low Load Factor	$0.00671	$0.00339
22				
23	OPCo	General Service - Medium/High Load Factor	($0.00006)	$0.00003
24				
25	OPCo	General Service - Large / Interruptible Power - Discretionary	($0.00352)	($0.00176)
26				
27	OPCo	Electric Heating General	($0.00459)	($0.00228)
28				
29	OPCo	Electric Heating Schools	($0.02215)	($0.01267)
30				
31	OPCo	School Service	$0.00145	$0.00072
32				
33	OPCo	Flood Pumping	($0.01192)	($0.00621)
34				
35	OPCo	Outdoor Lighting	$0.06166	$0.03084
36				
37	OPCo	Street Lighting	$0.05828	$0.02855
38				
39	OPCo	Standby Service	($0.26719)	($0.17655)

Exhibit DMR-4

Summary of ESP Rate Mechanisms

Line	Rate Mechanism	Abbreviation	Bypassable	Distribution	Notes
1	**Current Riders**				
2	Universal Service Fund Rider	USF	--	Yes	
3	Advanced Energy Fund Rider	AEF	--	Yes	Expired 12/31/2010
4	kWh Tax Rider	kWh Tax	--		May be self-assessed under specific terms
5	Provider of Last Resort Charge	POLR	No		Option to avoid under specific terms
6	Monongahela Power Litigation Termination Rider	Mon Power	--	Yes	Expires once amount collected
7	Transmission Cost Recovery Rider	TCRR	Yes		
8	Fuel Adjustment Clause Rider	FAC	Yes		
9	Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	EE/PDR	--	Yes	
10	Economic Development Cost Recovery Rider	EDR	--	Yes	
11	Enhanced Service Reliability Rider	ESRR	--	Yes	
12	gridSMART® Rider	gridSMART®	--	Yes	
13	Environmental Investment Carrying Cost Rider	EICCR	No		
14					
15	**Proposed Riders**				
16	Standard Offer Generation Service Rider	GSR	Yes		Relocation of base generation rates
17	Generation Resource Rider	GRR	No		Capital/solar investment
18	Alternative Energy Rider	AER	Yes		Relocation of RECs from FAC
19	Phase-In Recovery Rider	PIRR	--	Yes	Previous ESP deferrals, possibility of securitization
20	Distribution Investment Rider	DIR	--	Yes	
21	Market Transition Rider	MTR	--	Yes	
22	Generation NERC Compliance Cost Recovery Rider	NERCR	No		
23	Facility Closure Cost Recovery Rider	FCCR	No		
24	Carbon Capture and Sequestration Rider	CCSR	No		
25					
26	**Other Provisions**				
27	Green Power Portfolio Rider	GPPR	--		Voluntary
28	Rate Security Rider	RSR	--		Voluntary
29	Plug-In Electric Vehicle Tariff / Costs	PEV	--	Yes	Voluntary, Deferral of Costs
30	Emergency Curtailable Service Rider	ECS	--		Voluntary, pending
31	Storm Damage Recovery Mechanism		--	Yes	Reconciliation of storm experience to funding level
32	Pool Termination or Modification Provision		Yes		
33	PIPP Uncollectibles	PIPP	--	Yes	

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)
R-R-1						
Summer		0 kWh	5.68	5.68	(0.00)	0.00%
		30 kWh	9.06	9.36	0.30	3.29%
		70 kWh	13.56	14.27	0.71	5.23%
		120 kWh	19.20	20.41	1.21	6.29%
		200 kWh	28.21	30.23	2.02	7.16%
		300 kWh	39.48	42.51	3.03	7.67%
		500 kWh	62.01	67.06	5.05	8.15%
		700 kWh	84.55	91.62	7.07	8.36%
R-R-1						
Winter		0 kWh	5.68	5.68	(0.00)	0.00%
		30 kWh	9.06	9.13	0.07	0.73%
		70 kWh	13.56	13.73	0.17	1.23%
		120 kWh	19.20	19.48	0.28	1.45%
		200 kWh	28.21	28.68	0.47	1.67%
		300 kWh	39.48	40.19	0.71	1.79%
		500 kWh	62.01	63.19	1.18	1.91%
		700 kWh	84.55	86.20	1.65	1.95%
		800 kWh	95.82	97.70	1.88	1.96%
		1,000 kWh	109.03	115.75	6.72	6.17%
		1,250 kWh	125.54	138.32	12.78	10.18%
		1,500 kWh	142.05	160.88	18.83	13.26%
		2,000 kWh	175.08	206.01	30.93	17.67%
		4,000 kWh	306.26	385.61	79.35	25.91%
		5,000 kWh	371.84	475.41	103.57	27.85%
RR						
Summer		0 kWh	5.68	5.68	(0.00)	0.00%
		30 kWh	9.35	9.44	0.09	0.99%
		70 kWh	14.25	14.47	0.22	1.51%
		120 kWh	20.37	20.74	0.37	1.84%
		200 kWh	30.16	30.79	0.63	2.09%
		300 kWh	42.41	43.35	0.94	2.22%
		500 kWh	66.89	68.47	1.58	2.36%
		800 kWh	103.63	106.14	2.51	2.42%
		1,000 kWh	128.11	131.26	3.15	2.46%
		1,200 kWh	152.60	156.37	3.77	2.47%
		1,500 kWh	189.33	194.05	4.72	2.49%
		2,000 kWh	250.55	256.84	6.29	2.51%
		4,000 kWh	494.51	507.08	12.57	2.54%
		5,000 kWh	616.49	632.20	15.71	2.55%
		8,000 kWh	982.42	1,007.56	25.14	2.56%
		10,000 kWh	1,226.38	1,257.81	31.43	2.56%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
RR						
Winter		0	5.68	5.68	(0.00)	0.00%
		30	9.35	9.21	(0.14)	-1.49%
		70	14.25	13.92	(0.33)	-2.29%
		120	20.37	19.82	(0.55)	-2.72%
		200	30.16	29.24	(0.92)	-3.04%
		300	42.41	41.03	(1.38)	-3.26%
		500	66.89	64.60	(2.29)	-3.43%
		800	103.63	99.95	(3.68)	-3.55%
		1,000	116.84	118.00	1.16	0.99%
		1,200	130.05	136.05	6.00	4.62%
		1,500	149.86	163.13	13.27	8.86%
		2,000	182.88	208.26	25.38	13.88%
		4,000	314.06	387.86	73.80	23.50%
		5,000	379.65	477.65	98.00	25.81%
		8,000	576.42	747.05	170.63	29.60%
		10,000	707.60	926.64	219.04	30.96%
RR						
(SWH)	80 gal.	500	52.07	53.35	1.28	2.45%
Summer	80 gal.	800	88.80	91.02	2.22	2.50%
	80 gal.	1,000	113.29	116.14	2.85	2.51%
	80 gal.	1,500	174.51	178.93	4.42	2.53%
	80 gal.	2,000	235.73	241.72	5.99	2.54%
	80 gal.	4,000	479.68	491.96	12.28	2.56%
	80 gal.	6,000	723.64	742.20	18.56	2.57%
	80 gal.	8,000	967.60	992.44	24.84	2.57%
	100 gal.	500	52.07	53.35	1.28	2.45%
	100 gal.	800	83.86	85.98	2.12	2.53%
	100 gal.	1,000	108.34	111.10	2.76	2.54%
	100 gal.	1,500	169.56	173.89	4.33	2.55%
	100 gal.	2,000	230.78	236.68	5.90	2.56%
	100 gal.	4,000	474.74	486.92	12.18	2.57%
	100 gal.	6,000	718.70	737.16	18.46	2.57%
	100 gal.	8,000	962.65	987.40	24.75	2.57%
	120 gal.	500	52.07	53.35	1.28	2.45%
	120 gal.	800	78.91	80.94	2.03	2.57%
	120 gal.	1,000	103.40	106.06	2.66	2.57%
	120 gal.	1,500	164.62	168.85	4.23	2.57%
	120 gal.	2,000	225.84	231.64	5.80	2.57%
	120 gal.	4,000	469.80	481.88	12.08	2.57%
	120 gal.	6,000	713.75	732.12	18.37	2.57%
	120 gal.	8,000	957.71	982.36	24.65	2.57%
	120 gal.	10,000	1,201.67	1,232.61	30.94	2.57%
RR						
(SWH)	80 gal.	500	52.07	51.94	(0.13)	-0.24%
Winter	80 gal.	800	88.80	87.30	(1.50)	-1.69%
	80 gal.	1,000	113.29	110.87	(2.42)	-2.14%
	80 gal.	1,500	151.30	158.10	6.80	4.50%
	80 gal.	2,000	184.32	203.23	18.91	10.26%
	80 gal.	4,000	315.50	382.83	67.33	21.34%
	80 gal.	6,000	446.68	562.43	115.75	25.91%
	80 gal.	8,000	577.86	742.02	164.16	28.41%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
RR	100 gal.	500	52.07	51.94	(0.13)	-0.24%
(SWH)	100 gal.	800	83.86	83.08	(0.78)	-0.93%
Winter	100 gal.	1,000	108.34	106.65	(1.69)	-1.56%
	100 gal.	1,500	152.65	157.30	4.65	3.04%
	100 gal.	2,000	185.67	202.42	16.75	9.02%
	100 gal.	4,000	316.85	382.02	65.17	20.57%
	100 gal.	6,000	448.03	561.62	113.59	25.35%
	100 gal.	8,000	579.21	741.21	162.00	27.97%
	120 gal.	500	52.07	51.94	(0.13)	-0.24%
	120 gal.	800	78.91	78.86	(0.05)	-0.06%
	120 gal.	1,000	103.40	102.43	(0.97)	-0.94%
	120 gal.	1,500	153.34	155.84	2.50	1.63%
	120 gal.	2,000	186.37	200.97	14.60	7.83%
	120 gal.	4,000	317.55	380.56	63.01	19.84%
	120 gal.	6,000	448.72	560.16	111.44	24.83%
	120 gal.	8,000	579.90	739.75	159.85	27.57%
	120 gal.	10,000	711.08	919.35	208.27	29.29%
RLM						
Summer	5	500	69.04	72.69	3.65	5.29%
	5	1,500	160.65	173.65	13.00	8.10%
	5	2,500	242.31	265.35	23.04	9.51%
	10	1,000	128.47	136.08	7.61	5.92%
	10	3,000	309.31	336.24	26.93	8.71%
	10	5,000	472.17	519.17	47.00	9.95%
	20	2,000	245.41	261.55	16.14	6.58%
	20	6,000	606.18	660.96	54.78	9.04%
	20	10,000	931.89	1,026.82	94.93	10.19%
	30	3,000	361.89	386.56	24.67	6.82%
	30	9,000	903.04	985.67	82.63	9.15%
	30	15,000	1,391.61	1,534.47	142.86	10.27%
	40	4,000	478.37	511.57	33.20	6.94%
	40	12,000	1,199.90	1,310.39	110.49	9.21%
	40	20,000	1,848.53	2,039.31	190.78	10.32%
	50	5,000	594.85	636.58	41.73	7.02%
	50	15,000	1,496.76	1,635.10	138.34	9.24%
	50	25,000	2,305.44	2,544.16	238.72	10.35%
RLM						
Winter	5	500	69.04	68.82	(0.22)	-0.32%
	5	1,500	155.92	162.05	6.13	3.93%
	5	2,500	231.27	246.01	14.74	6.37%
	10	1,000	120.63	123.02	2.39	1.98%
	10	3,000	276.32	297.06	20.74	7.51%
	10	5,000	426.56	464.51	37.95	8.90%
	20	2,000	206.20	219.46	13.26	6.43%
	20	6,000	516.67	566.62	49.95	9.67%
	20	10,000	817.14	901.53	84.39	10.33%
	30	3,000	291.31	315.44	24.13	8.28%
	30	9,000	757.01	836.18	79.17	10.46%
	30	15,000	1,207.73	1,338.55	130.82	10.83%
	40	4,000	376.42	411.41	34.99	9.30%
	40	12,000	997.35	1,105.74	108.39	10.87%
	40	20,000	1,595.51	1,772.77	177.26	11.11%
	50	5,000	461.53	507.39	45.86	9.94%
	50	15,000	1,237.70	1,375.30	137.60	11.12%
	50	25,000	1,983.29	2,206.98	223.69	11.28%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
RS-ES						
Peak - 13%		1,000	93.28	95.30	2.02	2.17%
Off Peak - 87%		2,000	177.91	181.95	4.04	2.27%
		3,000	262.08	268.14	6.06	2.31%
		4,000	346.25	354.33	8.08	2.33%
		5,000	430.42	440.53	10.11	2.35%
		6,000	514.60	526.72	12.12	2.36%
		7,000	598.77	612.91	14.14	2.36%
		8,000	682.94	699.10	16.16	2.37%
RS-ES						
Peak - 18%		1,000	97.75	99.59	1.84	1.88%
Off Peak - 82%		2,000	186.85	190.52	3.67	1.97%
		3,000	275.48	281.00	5.52	2.00%
		4,000	364.12	371.48	7.36	2.02%
		5,000	452.76	461.95	9.19	2.03%
		6,000	541.40	552.43	11.03	2.04%
		7,000	630.03	642.91	12.88	2.04%
		8,000	718.67	733.38	14.71	2.05%
RS-ES						
Peak - 30%		1,000	108.47	109.87	1.40	1.29%
Off Peak - 70%		2,000	208.29	211.10	2.81	1.35%
		3,000	307.65	311.86	4.21	1.37%
		4,000	407.00	412.62	5.62	1.38%
		5,000	506.36	513.39	7.03	1.39%
		6,000	605.72	614.15	8.43	1.39%
		7,000	705.08	714.91	9.83	1.39%
		8,000	804.44	815.67	11.23	1.40%
GS-1						
Unmetered		50	11.74	11.15	(0.59)	-5.04%
		100	16.77	16.85	0.08	0.47%
		150	21.79	22.55	0.76	3.48%
		200	26.82	28.25	1.43	5.33%
		400	46.91	51.05	4.14	8.83%
		700	77.06	85.25	8.19	10.63%
		1,000	107.20	119.45	12.25	11.43%
		1,500	157.45	176.46	19.01	12.07%
		2,000	207.69	233.46	25.77	12.41%
		4,000	407.74	460.55	52.81	12.95%
GS-1		200	36.39	31.18	(5.21)	-14.32%
		400	63.14	53.98	(9.16)	-14.51%
		600	89.89	76.78	(13.11)	-14.58%
		800	116.63	99.58	(17.05)	-14.62%
		1,000	143.38	122.38	(21.00)	-14.64%
		1,200	163.55	145.19	(18.36)	-11.23%
		1,600	203.89	190.79	(13.10)	-6.43%
		1,800	224.06	213.59	(10.47)	-4.67%
		2,000	244.24	236.39	(7.85)	-3.21%
		2,400	284.40	281.81	(2.59)	-0.91%
		3,000	344.63	349.94	5.31	1.54%
		3,200	364.71	372.65	7.94	2.18%
		4,000	445.03	463.48	18.45	4.15%

COLUMBUS SOUTHERN POWER COMPANY
Case Nos. 11-346-EL-SSO and 11-348-EL-SSO
Typical Bill Comparison
(Annualized)

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-2	10	2,500	315.25	301.70	(13.55)	-4.30%
Secondary	10	3,000	365.61	348.11	(17.50)	-4.79%
	50	12,500	1,522.24	1,459.59	(62.65)	-4.12%
	50	15,000	1,774.03	1,691.64	(82.39)	-4.64%
	100	25,000	3,025.37	2,901.35	(124.02)	-4.10%
	100	30,000	3,526.16	3,362.65	(163.51)	-4.64%
	250	62,500	7,530.58	7,222.42	(308.16)	-4.09%
	250	75,000	8,782.54	8,375.67	(406.87)	-4.63%
	500	125,000	15,039.25	14,424.21	(615.04)	-4.09%
	500	150,000	17,543.18	16,730.71	(812.47)	-4.63%
	750	187,500	22,547.93	21,626.00	(921.93)	-4.09%
	750	225,000	26,303.83	25,085.75	(1,218.08)	-4.63%
	1,000	250,000	30,056.61	28,827.78	(1,228.83)	-4.09%
	1,000	300,000	35,064.47	33,440.79	(1,623.68)	-4.63%
	2,000	500,000	60,091.31	57,634.94	(2,456.37)	-4.09%
	2,000	600,000	70,107.03	66,860.94	(3,246.09)	-4.63%
GS-2						
Primary	50	5,000	822.83	801.85	(20.98)	-2.55%
	50	8,750	1,192.64	1,153.73	(38.91)	-3.26%
	50	12,500	1,562.44	1,497.65	(64.79)	-4.15%
	100	10,000	1,510.98	1,470.30	(40.68)	-2.69%
	100	17,500	2,249.19	2,172.66	(76.53)	-3.40%
	100	25,000	2,984.60	2,856.29	(128.31)	-4.30%
	250	25,000	3,569.85	3,470.04	(99.81)	-2.80%
	250	43,750	5,408.37	5,218.94	(189.43)	-3.50%
	250	62,500	7,246.90	6,928.01	(318.89)	-4.40%
	500	50,000	6,996.61	6,798.28	(198.33)	-2.83%
	500	87,500	10,673.66	10,296.06	(377.60)	-3.54%
	500	125,000	14,350.71	13,714.20	(636.51)	-4.44%
	1,000	100,000	13,850.15	13,454.74	(395.41)	-2.85%
	1,000	175,000	21,204.25	20,450.32	(753.93)	-3.56%
	1,000	250,000	28,558.35	27,286.60	(1,271.75)	-4.45%
	1,500	150,000	20,703.68	20,111.21	(592.47)	-2.86%
	1,500	262,500	31,734.83	30,604.57	(1,130.26)	-3.56%
	1,500	375,000	42,765.98	40,858.99	(1,906.99)	-4.46%
	2,000	200,000	27,557.22	26,767.68	(789.54)	-2.87%
	2,000	350,000	42,265.42	40,758.83	(1,506.59)	-3.56%
	2,000	500,000	56,973.62	54,431.39	(2,542.23)	-4.46%
	3,000	300,000	41,264.29	40,080.61	(1,183.68)	-2.87%
	3,000	525,000	63,326.59	61,067.34	(2,259.25)	-3.57%
	3,000	750,000	85,388.89	81,576.18	(3,812.71)	-4.47%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-3						
Secondary	50	17,500	1,838.30	1,776.02	(62.28)	-3.39%
	50	22,500	2,096.37	2,111.94	15.57	0.74%
	50	27,500	2,354.45	2,404.75	50.30	2.14%
	100	35,000	3,529.24	3,405.96	(123.28)	-3.49%
	100	45,000	4,045.39	4,077.80	32.41	0.80%
	100	55,000	4,561.54	4,663.42	101.88	2.23%
	250	87,500	8,602.06	8,295.78	(306.28)	-3.56%
	250	112,500	9,892.44	9,975.37	82.93	0.84%
	250	137,500	11,182.83	11,439.43	256.60	2.29%
	500	175,000	17,056.77	16,445.47	(611.30)	-3.58%
	500	225,000	19,637.53	19,804.66	167.13	0.85%
	500	275,000	22,218.30	22,732.77	514.47	2.32%
	1,000	350,000	33,966.18	32,744.86	(1,221.32)	-3.60%
	1,000	450,000	39,127.71	39,463.24	335.53	0.86%
	1,000	550,000	44,289.25	45,319.46	1,030.21	2.33%
	2,000	700,000	67,785.00	65,343.63	(2,441.37)	-3.60%
	2,000	900,000	77,967.38	78,639.71	672.33	0.86%
	2,000	1,100,000	87,870.49	89,932.18	2,061.69	2.35%
	3,000	1,050,000	101,148.16	97,486.74	(3,661.42)	-3.62%
	3,000	1,350,000	116,002.83	117,011.96	1,009.13	0.87%
	3,000	1,650,000	130,857.50	133,950.66	3,093.16	2.36%
	4,500	1,575,000	150,774.00	145,282.50	(5,491.50)	-3.64%
	4,500	2,025,000	173,056.00	174,570.33	1,514.33	0.88%
	4,500	2,475,000	195,338.00	199,978.39	4,640.39	2.38%
GS-3						
Primary	50	17,500	1,919.59	1,856.84	(62.75)	-3.27%
	50	22,500	2,171.76	2,183.70	11.94	0.55%
	50	27,500	2,423.94	2,468.94	45.00	1.86%
	100	35,000	3,525.02	3,400.79	(124.23)	-3.52%
	100	45,000	4,029.37	4,054.51	25.14	0.62%
	100	55,000	4,533.73	4,625.01	91.28	2.01%
	250	87,500	8,341.33	8,032.65	(308.68)	-3.70%
	250	112,500	9,602.21	9,666.95	64.74	0.67%
	250	137,500	10,863.09	11,093.20	230.11	2.12%
	500	175,000	16,368.51	15,752.42	(616.09)	-3.76%
	500	225,000	18,890.27	19,021.01	130.74	0.69%
	500	275,000	21,412.02	21,873.51	461.49	2.16%
	1,000	350,000	32,422.86	31,191.96	(1,230.90)	-3.80%
	1,000	450,000	37,466.38	37,729.14	262.76	0.70%
	1,000	550,000	42,509.90	43,434.14	924.24	2.17%
	2,000	700,000	64,531.58	62,071.04	(2,460.54)	-3.81%
	2,000	900,000	74,477.92	75,004.72	526.80	0.71%
	2,000	1,100,000	84,145.00	85,994.75	1,849.75	2.20%
	4,000	1,400,000	127,558.41	122,638.61	(4,919.80)	-3.86%
	4,000	1,800,000	146,892.56	147,947.42	1,054.86	0.72%
	4,000	2,200,000	166,226.70	169,927.48	3,700.78	2.23%
	8,000	2,800,000	253,053.54	243,215.20	(9,838.34)	-3.89%
	8,000	3,600,000	291,721.83	293,832.83	2,111.00	0.72%
	8,000	4,400,000	330,390.12	337,792.95	7,402.83	2.24%
	10,000	3,500,000	315,801.10	303,503.50	(12,297.60)	-3.89%
	10,000	4,500,000	364,136.47	366,775.54	2,639.07	0.72%
	10,000	5,500,000	412,471.83	421,725.69	9,253.86	2.24%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-4	3,000	600,000	70,325.91	50,269.07	(20,056.84)	-28.52%
	3,000	1,200,000	97,413.43	85,362.27	(12,051.16)	-12.37%
	3,000	1,800,000	124,011.71	111,136.49	(12,875.22)	-10.38%
	5,000	1,000,000	104,058.74	82,881.81	(21,176.93)	-20.35%
	5,000	2,000,000	148,389.20	140,555.06	(7,834.14)	-5.28%
	5,000	3,000,000	192,719.66	183,512.09	(9,207.57)	-4.78%
	8,000	1,600,000	153,924.11	131,067.04	(22,857.07)	-14.85%
	8,000	3,200,000	224,852.84	223,344.23	(1,508.61)	-0.67%
	8,000	4,800,000	295,781.58	292,075.48	(3,706.10)	-1.25%
	10,000	2,000,000	187,167.69	163,190.53	(23,977.16)	-12.81%
	10,000	4,000,000	275,828.60	278,537.02	2,708.42	0.98%
	10,000	6,000,000	364,489.52	364,451.08	(38.44)	-0.01%
	15,000	3,000,000	270,276.64	243,499.24	(26,777.40)	-9.91%
	15,000	6,000,000	403,268.01	416,518.98	13,250.97	3.29%
	15,000	9,000,000	536,259.39	545,390.07	9,130.68	1.70%
	20,000	4,000,000	353,385.58	323,807.96	(29,577.62)	-8.37%
	20,000	8,000,000	530,707.42	554,500.94	23,793.52	4.48%
	20,000	12,000,000	708,029.25	726,329.06	18,299.81	2.58%
	30,000	6,000,000	519,603.48	484,425.39	(35,178.09)	-6.77%
	30,000	12,000,000	785,586.23	830,464.86	44,878.63	5.71%
	30,000	18,000,000	1,051,568.99	1,088,207.04	36,638.05	3.48%
AL	Lamp Size					
	Mercury Vapor					
	100 WATT	43	9.21	10.09	0.88	9.51%
	175 WATT	72	10.66	12.89	2.23	20.88%
	400 WATT	158	18.57	23.00	4.43	23.85%
	POST TOP 175 WATT	72	16.96	19.18	2.22	13.10%
	High Pressure Sodium					
	100 WATT	40	8.97	9.16	0.19	2.07%
	150 WATT	59	10.69	11.12	0.43	4.01%
	200 WATT	84	13.99	14.46	0.47	3.37%
	250 WATT	103	15.34	16.18	0.84	5.50%
	400 WATT	167	20.20	22.97	2.77	13.72%
	POST TOP 100 WATT	40	17.05	16.04	(1.01)	-5.90%
	POST TOP 150 WATT	59	18.90	18.02	(0.88)	-4.66%
	CUT OFF 100 WATT	40	12.49	12.67	0.18	1.43%
	CUT OFF 250 WATT	103	21.43	20.96	(0.47)	-2.18%
	CUT OFF 400 WATT	167	23.34	27.42	4.08	17.48%
	FLOODLIGHT					
	High Pressure Sodium					
	100 WATT	40	9.56	9.59	0.03	0.31%
	250 WATT	103	17.39	16.40	(0.99)	-5.69%
	400 WATT	167	24.21	22.74	(1.47)	-6.06%
	1,000 WATT	378	61.68	42.67	(19.01)	-30.82%
	Metal Halide					
	250 WATT	100	18.24	17.34	(0.90)	-4.93%
	400 WATT	158	23.88	22.73	(1.15)	-4.84%
	1,000 WATT	378	61.62	42.62	(19.00)	-30.84%
	FACILITY CHARGES					
	Mast Arm					
	8 FT.	0	0.65	0.65	0.00	0.00%
	12 FT.	0	1.14	1.14	0.00	0.00%
	16 FT.	0	1.52	1.52	(0.00)	0.00%
	20 FT.	0	2.86	2.86	(0.00)	0.00%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
AL	Poles					
	Wood	0	2.50	2.50	(0.00)	0.00%
	Aluminum	0	13.67	13.67	0.00	0.00%
	Fiberglass	0	20.39	20.39	0.00	0.00%
	Each additional 150 foot overhead wire span	0	0.81	0.81	(0.00)	0.00%
	Each additional riser pole connection	0	4.01	4.01	0.00	0.00%
	Each underground lateral not over 50 feet	0	1.20	1.20	(0.00)	0.00%
SL	High Pressure Sodium					
	100 WATT	40	11.66	11.12	(0.54)	-4.67%
	150 WATT	59	13.58	13.38	(0.20)	-1.50%
	200 WATT	84	17.19	17.45	0.26	1.49%
	250 WATT	103	19.22	19.82	0.60	3.12%
	400 WATT	167	23.78	25.55	1.77	7.42%
	CUT OFF 100 WATT	40	14.92	14.38	(0.54)	-3.63%
	CUT OFF 250 WATT	103	24.42	25.02	0.60	2.46%
	CUT OFF 400 WATT	167	32.24	34.01	1.77	5.48%
	Mercury Vapor					
	100 WATT	43	11.15	10.66	(0.49)	-4.37%
	175 WATT	72	13.54	13.58	0.04	0.29%
	400 WATT	158	22.50	24.10	1.60	7.11%
	FACILITY CHARGES					
	Mast Arm					
	12 FT.	0	1.14	1.14	0.00	0.00%
	16 FT.	0	1.52	1.52	(0.00)	0.00%
	20 FT.	0	2.66	2.66	(0.00)	0.00%
	Poles					
	Wood	0	1.30	1.30	0.00	0.00%
	Aluminum	0	13.50	13.50	0.00	0.00%
	Fiberglass	0	20.13	20.13	(0.00)	0.00%
	Each additional 150 foot overhead wire span	0	0.76	0.76	0.00	0.00%
	Each additional riser pole connection	0	3.90	3.90	0.00	0.00%
	Each underground lateral not over 50 feet	0	1.24	1.24	0.00	0.00%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
RS		0	4.37	4.37	-	0.00%
		30	7.70	7.84	0.14	1.79%
		70	12.15	12.47	0.32	2.64%
		120	17.71	18.26	0.55	3.11%
		200	26.60	27.52	0.92	3.45%
		300	37.72	39.09	1.38	3.65%
		500	59.95	62.24	2.29	3.83%
		800	93.30	96.97	3.67	3.93%
		1,000	113.13	118.65	5.51	4.87%
		1,200	132.96	140.32	7.36	5.53%
		1,500	162.71	172.84	10.12	6.22%
		2,000	212.29	227.03	14.73	6.94%
		4,000	409.69	442.87	33.17	8.10%
		5,000	508.40	550.79	42.39	8.34%
		8,000	804.50	874.55	70.06	8.71%
		10,000	1,001.90	1,090.40	88.50	8.83%
		12,000	1,199.30	1,306.24	106.94	8.92%
		15,000	1,495.41	1,630.00	134.60	9.00%
RS						
SWH	80 gal.	500	49.51	52.79	3.29	6.64%
	80 gal.	800	82.85	87.52	4.66	5.63%
	80 gal.	1,000	105.09	110.67	5.58	5.31%
	80 gal.	1,500	155.27	165.23	9.96	6.41%
	80 gal.	2,000	204.85	219.42	14.57	7.11%
	80 gal.	4,000	402.25	435.26	33.01	8.21%
	80 gal.	6,000	599.65	651.10	51.45	8.58%
	80 gal.	8,000	797.05	866.94	69.89	8.77%
RS						
SWH	100 gal.	500	46.24	48.82	2.58	5.57%
	100 gal.	800	78.68	83.74	5.06	6.43%
	100 gal.	1,000	100.91	106.88	5.98	5.92%
	100 gal.	1,500	152.29	162.18	9.89	6.49%
	100 gal.	2,000	201.87	216.37	14.50	7.18%
	100 gal.	4,000	399.27	432.21	32.94	8.25%
	100 gal.	6,000	596.67	648.06	51.38	8.61%
	100 gal.	8,000	794.08	863.90	69.82	8.79%
	120 gal.	500	46.24	48.82	2.58	5.57%
	120 gal.	800	74.50	79.95	5.45	7.32%
	120 gal.	1,000	96.73	103.10	6.37	6.59%
	120 gal.	1,500	149.31	159.14	9.82	6.58%
	120 gal.	2,000	198.89	213.33	14.43	7.26%
	120 gal.	4,000	396.29	429.17	32.87	8.30%
	120 gal.	6,000	593.70	645.01	51.31	8.64%
	120 gal.	8,000	791.10	860.85	69.76	8.82%
	120 gal.	10,000	988.50	1,076.70	88.20	8.92%
RS-TOD						
On - Peak	25%	1,000	99.49	105.64	6.15	6.18%
Off-Peak	75%	2,000	190.24	202.54	12.30	6.47%
		3,000	280.53	298.98	18.45	6.58%
		4,000	370.81	395.41	24.60	6.63%
		5,000	461.10	491.85	30.75	6.67%
		6,000	551.39	588.29	36.90	6.69%
		7,000	641.68	684.73	43.05	6.71%
		8,000	731.97	781.17	49.20	6.72%

OHIO POWER COMPANY
Case Nos. 11-346-EL-SSO and 11-348-EL-SSO
Typical Bill Comparison
(Annualized)

Rate Code		Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
RS-TOD							
On - Peak	30%		1,000	103.76	109.43	5.67	5.46%
Off-Peak	70%		2,000	198.78	210.12	11.34	5.70%
			3,000	293.34	310.35	17.01	5.80%
			4,000	387.91	410.58	22.68	5.85%
			5,000	482.47	510.81	28.35	5.88%
			6,000	577.03	611.04	34.02	5.90%
			7,000	671.59	711.28	39.69	5.91%
			8,000	766.15	811.51	45.36	5.92%
RS-TOD							
On - Peak	35%		1,000	108.03	113.22	5.19	4.80%
Off-Peak	65%		2,000	207.33	217.71	10.38	5.01%
			3,000	306.16	321.73	15.57	5.08%
			4,000	405.00	425.75	20.76	5.12%
			5,000	503.83	529.78	25.94	5.15%
			6,000	602.67	633.80	31.13	5.17%
			7,000	701.50	737.82	36.32	5.18%
			8,000	800.33	841.84	41.51	5.19%
RS-ES							
On - Peak	15%		1,000	90.94	98.05	7.11	7.82%
Off-Peak	85%		2,000	173.14	187.37	14.22	8.21%
			3,000	254.89	276.22	21.33	8.37%
			4,000	336.63	365.08	28.44	8.45%
			5,000	418.37	453.93	35.56	8.50%
			6,000	500.12	542.78	42.67	8.53%
			7,000	581.86	631.64	49.78	8.55%
			8,000	663.60	720.49	56.89	8.57%
RS-ES							
On - Peak	20%		1,000	95.21	101.85	6.63	6.96%
Off-Peak	80%		2,000	181.69	194.95	13.26	7.30%
			3,000	267.71	287.60	19.89	7.43%
			4,000	353.72	380.24	26.52	7.50%
			5,000	439.74	472.89	33.15	7.54%
			6,000	525.75	565.54	39.78	7.57%
			7,000	611.77	658.18	46.41	7.59%
			8,000	697.79	750.83	53.04	7.60%
RS-ES							
On - Peak	25%		1,000	99.49	105.64	6.15	6.18%
Off-Peak	75%		2,000	190.24	202.54	12.30	6.47%
			3,000	280.53	298.98	18.45	6.58%
			4,000	370.81	395.41	24.60	6.63%
			5,000	461.10	491.85	30.75	6.67%
			6,000	551.39	588.29	36.90	6.69%
			7,000	641.68	684.73	43.05	6.71%
			8,000	731.97	781.17	49.20	6.72%

Rate Code		Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-1							
Unmetered			50	13.12	14.22	1.10	8.37%
			100	17.84	19.04	1.20	6.71%
			150	22.56	23.86	1.30	5.74%
			200	27.28	28.67	1.39	5.11%
			400	46.15	47.93	1.79	3.87%
			700	74.45	76.83	2.38	3.19%
			1,000	102.75	105.72	2.97	2.89%
			1,500	149.93	153.88	3.95	2.64%
			2,000	197.10	202.04	4.94	2.51%
			4,000	384.88	393.76	8.88	2.31%
			8,000	760.43	777.18	16.75	2.20%
			10,000	948.20	968.89	20.69	2.18%
			15,000	1,417.64	1,448.17	30.53	2.15%
			25,000	2,350.91	2,401.13	50.22	2.14%
GS-1-ES							
On-Peak	10%		500	54.19	61.26	7.07	13.05%
Off-Peak	90%		1,000	91.13	104.27	13.14	14.42%
			2,000	165.01	190.29	25.28	15.32%
			4,000	311.84	361.40	49.56	15.89%
			6,000	458.68	532.52	73.84	16.10%
			8,000	605.52	703.63	98.12	16.20%
On-Peak	15%		500	55.46	61.87	6.41	11.56%
Off-Peak	85%		1,000	93.66	105.49	11.83	12.63%
			2,000	170.08	192.73	22.65	13.32%
			4,000	321.99	366.29	44.30	13.76%
			6,000	473.90	539.85	65.95	13.92%
			8,000	625.81	713.42	87.61	14.00%
On-Peak	20%		500	56.73	62.48	5.76	10.15%
Off-Peak	80%		1,000	96.20	106.71	10.51	10.93%
			2,000	175.15	195.18	20.02	11.43%
			4,000	332.14	371.18	39.05	11.76%
			6,000	489.12	547.19	58.07	11.87%
			8,000	646.10	723.20	77.10	11.93%
GS-1							
			600	71.67	73.85	2.18	3.04%
			700	81.11	83.49	2.38	2.93%
			800	90.54	93.12	2.58	2.84%
			900	99.98	102.75	2.77	2.77%
			1,200	128.28	131.64	3.36	2.62%
			1,400	147.15	150.91	3.76	2.55%
			1,600	166.02	170.17	4.15	2.50%
			1,800	184.89	189.43	4.54	2.46%
			2,100	213.15	218.28	5.13	2.41%
			2,400	241.31	247.04	5.73	2.37%
			2,700	269.48	275.80	6.32	2.34%
			2,800	278.87	285.38	6.51	2.34%
			3,000	297.65	304.55	6.91	2.32%
			3,200	316.42	323.72	7.30	2.31%
			3,500	344.59	352.48	7.89	2.29%
			3,600	353.98	362.07	8.09	2.28%
			4,000	391.53	400.41	8.88	2.27%
			4,500	438.48	448.34	9.86	2.25%

OHIO POWER COMPANY
Case Nos. 11-346-EL-SSO and 11-348-EL-SSO
Typical Bill Comparison
(Annualized)

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-2-						
Rec. Lighting		50	24.70	25.69	0.99	3.99%
		100	29.69	30.66	0.97	3.27%
		150	34.68	35.64	0.96	2.76%
		200	39.67	40.62	0.94	2.38%
		400	59.64	60.52	0.89	1.49%
		700	89.59	90.39	0.80	0.89%
		1,000	119.53	120.26	0.72	0.60%
		1,500	169.44	170.02	0.57	0.34%
		2,000	219.36	219.79	0.43	0.20%
		4,000	418.08	417.95	(0.14)	-0.03%
		8,000	815.54	814.26	(1.27)	-0.16%
		10,000	1,014.26	1,012.42	(1.84)	-0.18%
		15,000	1,511.08	1,507.82	(3.26)	-0.22%
		25,000	2,499.12	2,493.01	(6.10)	-0.24%
GS-2						
Secondary	10	1,000	149.78	153.17	3.39	2.26%
	10	2,000	233.59	238.51	4.91	2.10%
	10	3,000	316.95	320.08	3.14	0.99%
	25	2,500	334.90	341.88	6.98	2.08%
	25	5,000	543.29	554.08	10.79	1.99%
	25	7,500	751.67	758.02	6.35	0.84%
	50	5,000	642.68	655.63	12.95	2.02%
	50	10,000	1,059.45	1,080.02	20.57	1.94%
	50	15,000	1,476.22	1,487.91	11.69	0.79%
	75	7,500	950.46	969.39	18.93	1.99%
	75	15,000	1,575.61	1,605.97	30.36	1.93%
	75	22,500	2,196.57	2,213.61	17.04	0.78%
	100	10,000	1,258.23	1,283.14	24.91	1.98%
	100	20,000	2,088.97	2,129.12	40.15	1.92%
	100	30,000	2,916.92	2,939.30	22.39	0.77%
	200	20,000	2,486.54	2,535.36	48.82	1.96%
	200	40,000	4,142.42	4,221.72	79.30	1.91%
	200	60,000	5,798.31	5,842.08	43.77	0.75%
	500	50,000	6,163.06	6,283.60	120.54	1.96%
	500	100,000	10,302.77	10,499.51	196.74	1.91%
	500	150,000	14,442.48	14,550.41	107.93	0.75%
	1,000	100,000	12,290.60	12,530.67	240.08	1.95%
	1,000	200,000	20,570.01	20,962.50	392.49	1.91%
	1,000	300,000	28,849.43	29,064.29	214.86	0.74%
	3,000	300,000	36,800.73	37,518.96	718.23	1.95%
	3,000	600,000	61,638.99	62,814.45	1,175.46	1.91%
	3,000	900,000	86,315.98	86,958.56	642.58	0.74%
	7,000	700,000	85,821.01	87,495.54	1,674.53	1.95%
	7,000	1,400,000	142,412.22	145,153.63	2,741.41	1.92%
	7,000	2,100,000	198,683.32	200,181.33	1,498.02	0.75%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-2						
Primary	10	1,000	221.84	224.76	2.91	1.31%
	10	2,000	303.83	307.82	3.99	1.31%
	10	3,000	385.36	387.24	1.88	0.49%
	25	2,500	390.57	396.35	5.79	1.48%
	25	5,000	594.38	602.86	8.48	1.43%
	25	7,500	798.20	801.40	3.20	0.40%
	50	5,000	671.01	681.58	10.57	1.58%
	50	10,000	1,078.64	1,094.60	15.95	1.48%
	50	15,000	1,486.28	1,491.68	5.40	0.36%
	75	7,500	951.45	966.81	15.36	1.61%
	75	15,000	1,562.90	1,586.33	23.43	1.50%
	75	22,500	2,170.16	2,177.76	7.61	0.35%
	100	10,000	1,231.89	1,252.04	20.15	1.64%
	100	20,000	2,044.36	2,075.27	30.91	1.51%
	100	30,000	2,854.04	2,863.84	9.81	0.34%
	200	20,000	2,350.85	2,390.15	39.30	1.67%
	200	40,000	3,970.20	4,031.01	60.81	1.53%
	200	60,000	5,589.55	5,608.16	18.61	0.33%
	500	50,000	5,699.33	5,796.07	96.74	1.70%
	500	100,000	9,747.70	9,898.24	150.54	1.54%
	500	150,000	13,796.07	13,841.11	45.04	0.33%
	1,000	100,000	11,280.14	11,472.62	192.49	1.71%
	1,000	200,000	19,376.88	19,676.95	300.07	1.55%
	1,000	300,000	27,473.62	27,562.70	89.07	0.32%
	3,000	300,000	33,603.36	34,178.82	575.46	1.71%
	3,000	600,000	57,893.59	58,791.81	898.22	1.55%
	3,000	900,000	82,022.56	82,287.78	265.22	0.32%
	7,000	700,000	78,249.81	79,591.21	1,341.40	1.71%
	7,000	1,400,000	133,562.30	135,656.81	2,094.51	1.57%
	7,000	2,100,000	188,554.67	189,172.18	617.51	0.33%
GS-2						
Subtransmission	10	1,000	418.14	420.96	2.81	0.67%
	10	2,000	498.95	502.75	3.80	0.76%
	10	3,000	579.29	580.97	1.67	0.29%
	25	2,500	578.27	583.80	5.53	0.96%
	25	5,000	779.13	787.14	8.01	1.03%
	25	7,500	980.00	982.68	2.68	0.27%
	50	5,000	844.39	854.45	10.06	1.19%
	50	10,000	1,246.11	1,261.13	15.01	1.20%
	50	15,000	1,647.84	1,652.20	4.37	0.26%
	75	7,500	1,110.51	1,125.10	14.59	1.31%
	75	15,000	1,713.09	1,735.11	22.02	1.29%
	75	22,500	2,311.48	2,317.53	6.05	0.26%
	100	10,000	1,376.62	1,395.74	19.12	1.39%
	100	20,000	2,177.27	2,206.30	29.03	1.33%
	100	30,000	2,975.12	2,982.85	7.73	0.26%
	200	20,000	2,438.29	2,475.53	37.24	1.53%
	200	40,000	4,033.98	4,091.04	57.05	1.41%
	200	60,000	5,629.68	5,644.14	14.46	0.26%
	500	50,000	5,614.89	5,706.50	91.61	1.63%
	500	100,000	9,604.12	9,745.26	141.13	1.47%
	500	150,000	13,593.36	13,628.02	34.66	0.25%
	1,000	100,000	10,909.22	11,091.44	182.21	1.67%
	1,000	200,000	18,887.69	19,168.96	281.27	1.49%
	1,000	300,000	26,866.16	26,934.48	68.32	0.25%
	3,000	300,000	32,086.56	32,631.20	544.64	1.70%
	3,000	600,000	56,021.97	56,863.77	841.81	1.50%
	3,000	900,000	79,796.11	79,999.06	202.95	0.25%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
GS-2	7,000	700,000	74,441.22	75,710.73	1,269.50	1.71%
Subtransmission	7,000	1,400,000	128,925.80	130,888.68	1,962.88	1.52%
	7,000	2,100,000	183,090.25	183,562.48	472.22	0.26%
GS-3						
Secondary	10	3,500	369.19	358.21	(10.98)	-2.97%
	10	4,500	421.07	422.97	1.91	0.45%
	10	5,500	472.94	479.11	6.17	1.30%
	25	8,750	882.29	853.34	(28.94)	-3.28%
	25	11,250	1,011.98	1,015.24	3.26	0.32%
	25	13,750	1,141.67	1,155.58	13.92	1.22%
	50	17,500	1,736.05	1,677.16	(58.88)	-3.39%
	50	22,500	1,992.63	1,998.16	5.53	0.28%
	50	27,500	2,249.21	2,276.04	26.83	1.19%
	75	26,250	2,586.31	2,497.48	(88.82)	-3.43%
	75	33,750	2,971.18	2,978.97	7.79	0.26%
	75	41,250	3,356.05	3,395.80	39.75	1.18%
	100	35,000	3,436.56	3,317.80	(118.77)	-3.46%
	100	45,000	3,949.73	3,959.78	10.06	0.25%
	100	55,000	4,462.89	4,515.55	52.66	1.18%
	200	70,000	6,837.60	6,599.07	(238.53)	-3.49%
	200	90,000	7,863.93	7,883.04	19.11	0.24%
	200	110,000	8,890.26	8,994.58	104.32	1.17%
	500	175,000	17,040.72	16,442.89	(597.83)	-3.51%
	500	225,000	19,606.53	19,652.82	46.28	0.24%
	500	275,000	22,172.35	22,431.66	259.31	1.17%
	1,000	350,000	34,045.91	32,849.26	(1,196.66)	-3.51%
	1,000	450,000	39,177.64	39,269.11	91.57	0.23%
	1,000	550,000	44,309.17	44,826.79	517.62	1.17%
	3,000	1,050,000	101,544.39	97,952.42	(3,591.97)	-3.54%
	3,000	1,350,000	116,217.21	116,489.91	272.70	0.23%
	3,000	1,650,000	130,890.03	132,440.88	1,550.85	1.18%
	7,000	2,450,000	234,216.27	225,833.68	(8,382.59)	-3.58%
	7,000	3,150,000	268,452.86	269,087.82	634.96	0.24%
	7,000	3,850,000	302,689.45	306,306.77	3,617.32	1.20%
GS-3						
Primary	10	3,500	436.30	423.55	(12.76)	-2.92%
	10	4,500	487.41	486.49	(0.92)	-0.19%
	10	5,500	538.51	541.11	2.60	0.48%
	25	8,750	925.57	892.18	(33.40)	-3.61%
	25	11,250	1,053.33	1,049.54	(3.80)	-0.36%
	25	13,750	1,181.10	1,186.10	5.00	0.42%
	50	17,500	1,739.62	1,671.83	(67.79)	-3.90%
	50	22,500	1,992.34	1,983.75	(8.59)	-0.43%
	50	27,500	2,245.07	2,254.07	9.00	0.40%
	75	26,250	2,550.17	2,447.98	(102.19)	-4.01%
	75	33,750	2,929.25	2,915.87	(13.39)	-0.46%
	75	41,250	3,308.34	3,321.34	13.00	0.39%
	100	35,000	3,360.71	3,224.13	(136.58)	-4.06%
	100	45,000	3,866.16	3,847.98	(18.18)	-0.47%
	100	55,000	4,371.61	4,388.61	17.00	0.39%
	200	70,000	6,602.90	6,328.73	(274.17)	-4.15%
	200	90,000	7,613.80	7,576.43	(37.36)	-0.49%
	200	110,000	8,624.69	8,657.70	33.01	0.38%
	500	175,000	16,329.46	15,642.54	(686.92)	-4.21%
	500	225,000	18,856.70	18,761.80	(94.90)	-0.50%
	500	275,000	21,383.94	21,464.96	81.02	0.38%
	1,000	350,000	32,540.39	31,165.55	(1,374.84)	-4.23%
	1,000	450,000	37,594.87	37,404.07	(190.81)	-0.51%

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GS-3	1,000	550,000	42,649.36	42,810.40	161.04	0.38%
Primary	3,000	1,050,000	96,861.82	92,735.29	(4,126.53)	-4.26%
	3,000	1,350,000	111,303.20	110,728.78	(574.42)	-0.52%
	3,000	1,650,000	125,744.59	126,225.71	481.12	0.38%
	7,000	2,450,000	223,179.61	213,549.71	(9,629.90)	-4.31%
	7,000	3,150,000	256,876.18	255,534.53	(1,341.65)	-0.52%
	7,000	3,850,000	290,572.75	291,694.02	1,121.27	0.39%
GS-3						
Subtransmission	10	3,500	629.10	616.55	(12.55)	-2.00%
	10	4,500	679.66	678.48	(1.18)	-0.17%
	10	5,500	730.22	732.27	2.04	0.28%
	25	8,750	1,104.52	1,071.63	(32.88)	-2.98%
	25	11,250	1,230.92	1,226.48	(4.44)	-0.36%
	25	13,750	1,357.32	1,360.93	3.61	0.27%
	50	17,500	1,895.48	1,828.71	(66.77)	-3.52%
	50	22,500	2,145.48	2,135.60	(9.88)	-0.46%
	50	27,500	2,395.49	2,401.71	6.22	0.26%
	75	26,250	2,682.94	2,582.29	(100.65)	-3.75%
	75	33,750	3,057.94	3,042.62	(15.32)	-0.50%
	75	41,250	3,432.95	3,441.79	8.83	0.26%
	100	35,000	3,470.40	3,335.88	(134.53)	-3.88%
	100	45,000	3,970.41	3,949.64	(20.77)	-0.52%
	100	55,000	4,470.42	4,481.86	11.45	0.26%
	200	70,000	6,620.23	6,350.17	(270.06)	-4.08%
	200	90,000	7,620.26	7,577.73	(42.53)	-0.56%
	200	110,000	8,620.28	8,642.17	21.89	0.25%
	500	175,000	16,069.75	15,393.09	(676.66)	-4.21%
	500	225,000	18,569.81	18,461.98	(107.83)	-0.58%
	500	275,000	21,069.87	21,123.09	53.23	0.25%
	1,000	350,000	31,818.95	30,464.62	(1,354.32)	-4.26%
	1,000	450,000	36,819.06	36,602.40	(216.66)	-0.59%
	1,000	550,000	41,819.18	41,924.63	105.46	0.25%
	3,000	1,050,000	94,293.43	90,228.46	(4,064.97)	-4.31%
	3,000	1,350,000	108,571.71	107,919.73	(651.98)	-0.60%
	3,000	1,650,000	122,849.98	123,164.35	314.37	0.26%
	7,000	2,450,000	216,917.34	207,431.07	(9,486.27)	-4.37%
	7,000	3,150,000	250,233.31	248,710.69	(1,522.62)	-0.61%
	7,000	3,850,000	283,549.28	284,281.47	732.19	0.26%
GS-4						
Primary	3,000	1,200,000	100,425.38	98,776.58	(1,648.80)	-1.64%
	3,000	1,500,000	113,520.48	114,917.53	1,397.05	1.23%
	3,000	1,800,000	126,615.58	128,426.19	1,810.61	1.43%
	5,000	2,000,000	165,909.02	163,160.35	(2,748.67)	-1.66%
	5,000	2,500,000	187,734.18	190,061.93	2,327.75	1.24%
	5,000	3,000,000	209,559.35	212,576.37	3,017.02	1.44%
	8,000	3,200,000	264,134.48	259,736.01	(4,398.47)	-1.67%
	8,000	4,000,000	299,054.74	302,778.54	3,723.80	1.25%
	8,000	4,800,000	333,975.01	338,801.63	4,826.63	1.45%
	20,000	8,000,000	657,036.31	646,038.64	(10,997.67)	-1.67%
	20,000	10,000,000	744,336.98	753,644.97	9,307.99	1.25%
	20,000	12,000,000	831,637.64	843,702.71	12,065.07	1.45%
	50,000	20,000,000	1,639,290.91	1,611,795.23	(27,495.68)	-1.68%
	50,000	25,000,000	1,857,542.57	1,880,811.05	23,268.49	1.25%
	50,000	30,000,000	2,075,794.23	2,105,955.40	30,161.17	1.45%
	125,000	50,000,000	4,094,927.39	4,026,186.69	(68,740.70)	-1.68%
	125,000	62,500,000	4,640,556.54	4,698,726.25	58,169.71	1.25%
	125,000	75,000,000	5,186,185.69	5,261,587.11	75,401.42	1.45%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)
GS-4						
Subtransmission	3,000	1,200,000	93,694.72	91,925.31	(1,769.41)	-1.89%
	3,000	1,500,000	106,651.89	107,788.57	1,136.68	1.07%
	3,000	1,800,000	119,609.06	121,070.49	1,461.43	1.22%
	5,000	2,000,000	154,487.40	151,537.72	(2,949.68)	-1.91%
	5,000	2,500,000	176,082.68	177,976.49	1,893.81	1.08%
	5,000	3,000,000	197,677.96	200,113.02	2,435.06	1.23%
	8,000	3,200,000	245,676.42	240,956.34	(4,720.08)	-1.92%
	8,000	4,000,000	280,228.87	283,258.36	3,029.49	1.08%
	8,000	4,800,000	314,781.32	318,676.82	3,895.49	1.24%
	20,000	8,000,000	610,432.50	598,630.79	(11,801.70)	-1.93%
	20,000	10,000,000	696,813.63	704,385.85	7,572.22	1.09%
	20,000	12,000,000	783,194.76	792,931.99	9,737.23	1.24%
	50,000	20,000,000	1,522,322.69	1,492,816.94	(29,505.76)	-1.94%
	50,000	25,000,000	1,738,275.53	1,757,204.59	18,929.06	1.09%
	50,000	30,000,000	1,954,228.36	1,978,569.93	24,341.57	1.25%
	125,000	50,000,000	3,802,048.19	3,728,282.29	(73,765.90)	-1.94%
	125,000	62,500,000	4,341,930.27	4,389,251.42	47,321.15	1.09%
	125,000	75,000,000	4,881,812.35	4,942,664.78	60,852.42	1.25%
GS-4						
Transmission	3,000	1,200,000	90,765.61	89,574.66	(1,190.95)	-1.31%
	3,000	1,500,000	103,710.00	105,437.92	1,727.92	1.67%
	3,000	1,800,000	116,654.39	118,719.84	2,065.45	1.77%
	5,000	2,000,000	149,525.47	147,539.90	(1,985.58)	-1.33%
	5,000	2,500,000	171,099.46	173,978.66	2,879.20	1.68%
	5,000	3,000,000	192,673.44	196,115.20	3,441.76	1.79%
	8,000	3,200,000	237,665.27	234,487.74	(3,177.53)	-1.34%
	8,000	4,000,000	272,183.64	276,789.77	4,606.13	1.69%
	8,000	4,800,000	306,702.02	312,208.22	5,506.21	1.80%
	20,000	8,000,000	590,224.45	582,279.14	(7,945.31)	-1.35%
	20,000	10,000,000	676,520.38	688,034.20	11,513.82	1.70%
	20,000	12,000,000	762,816.31	776,580.33	13,764.02	1.80%
	50,000	20,000,000	1,471,622.40	1,451,757.61	(19,864.78)	-1.35%
	50,000	25,000,000	1,687,362.23	1,716,145.27	28,783.04	1.71%
	50,000	30,000,000	1,903,102.06	1,937,510.61	34,408.55	1.81%
	125,000	50,000,000	3,675,117.27	3,625,453.81	(49,663.46)	-1.35%
	125,000	62,500,000	4,214,466.84	4,286,422.94	71,956.10	1.71%
	125,000	75,000,000	4,753,816.42	4,839,836.30	86,019.88	1.81%
EHG						
	30	100	34.10	35.83	1.73	5.07%
	30	500	70.03	74.67	4.65	6.64%
	30	1,000	114.93	123.23	8.29	7.22%
	30	3,000	294.10	316.98	22.88	7.78%
	30	4,500	428.13	460.65	32.52	7.60%
	30	6,000	562.16	604.32	42.16	7.50%
	30	9,000	830.22	881.76	51.54	6.21%
	30	12,000	1,098.28	1,142.04	43.76	3.98%
	30	15,000	1,366.34	1,377.87	11.52	0.84%
	30	20,000	1,810.31	1,721.45	(88.86)	-4.91%
	50	5,000	539.72	537.27	(2.45)	-0.45%
	50	7,500	763.10	776.72	13.62	1.78%
	50	10,000	986.48	1,016.17	29.69	3.01%
	50	15,000	1,433.25	1,478.57	45.32	3.16%
	50	20,000	1,877.22	1,909.57	32.35	1.72%
	50	25,000	2,321.19	2,299.81	(21.37)	-0.92%
	100	10,000	1,153.75	1,087.99	(65.76)	-5.70%
	100	15,000	1,600.52	1,566.89	(33.63)	-2.10%
	100	20,000	2,044.49	2,042.99	(1.50)	-0.07%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
EHG	100	30,000	2,932.43	2,962.19	29.76	1.01%
	100	40,000	3,820.36	3,824.19	3.82	0.10%
	200	20,000	2,379.03	2,186.64	(192.39)	-8.09%
	200	30,000	3,266.96	3,138.84	(128.13)	-3.92%
	200	40,000	4,154.90	4,091.04	(63.86)	-1.54%
	200	60,000	5,930.77	5,929.43	(1.34)	-0.02%
EHS	55	15,000	878.53	923.11	44.58	5.07%
	150	30,000	1,747.75	1,865.78	118.03	6.75%
	225	65,000	3,775.92	3,955.80	179.88	4.76%
SS						
1,000 sq ft	10	1,500	179.21	185.01	5.80	3.24%
	10	3,000	321.22	327.98	6.76	2.10%
	10	4,500	463.00	456.41	(6.59)	-1.42%
5,000 sq ft	20	2,000	227.98	234.79	6.81	2.99%
	20	4,000	417.01	429.50	12.49	2.99%
	20	6,000	606.05	617.61	11.56	1.91%
10,000 sq ft	20	2,000	228.51	234.79	6.28	2.75%
	20	4,000	418.61	429.50	10.89	2.60%
	20	6,000	607.65	617.61	9.96	1.64%
	40	5,000	513.13	528.59	15.46	3.01%
	40	7,500	749.43	771.98	22.55	3.01%
	40	10,000	985.73	1,008.77	23.05	2.34%
20,000 sq ft	50	10,000	988.92	1,016.24	27.32	2.76%
	50	15,000	1,461.52	1,486.52	25.00	1.71%
	50	20,000	1,931.31	1,925.40	(5.91)	-0.31%
30,000 sq ft	50	10,000	992.12	1,016.24	24.12	2.43%
	50	15,000	1,464.71	1,486.52	21.81	1.49%
	50	20,000	1,934.51	1,925.40	(9.11)	-0.47%
	100	20,000	1,934.51	1,991.34	56.83	2.94%
	100	25,000	2,404.30	2,458.82	54.52	2.27%
	100	30,000	2,874.09	2,926.30	52.20	1.82%
50,000 sq ft	100	15,000	1,471.10	1,507.35	36.25	2.46%
	100	30,000	2,880.49	2,926.30	45.81	1.59%
	200	40,000	3,820.08	3,935.93	115.85	3.03%
	200	60,000	5,699.25	5,805.85	106.60	1.87%
	300	60,000	5,699.25	5,880.52	181.27	3.18%
	300	80,000	7,578.43	7,750.45	172.02	2.27%
100,000 sq ft	250	60,000	5,715.23	5,843.19	127.96	2.24%
	250	80,000	7,594.41	7,684.51	90.10	1.19%
	400	80,000	7,594.41	7,825.12	230.71	3.04%
	400	120,000	11,352.76	11,564.96	212.20	1.87%
OL						
	Lamp Size					
	Mercury Vapor					
	7,000 Lumen	72	13.71	14.22	0.51	3.69%
	20,000 Lumen	158	22.31	25.53	3.21	14.39%
	High Pressure Sodium					
	9,000 Lumen	40	10.49	9.89	(0.59)	-5.64%
	22,000 Lumen	84	15.08	15.82	0.74	4.89%

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
OL	Incandescent					
	2,500 Lumen	63	10.88	14.91	4.03	37.09%
	4,000 Lumen	98	13.15	19.42	6.28	47.74%
	MV Floodlight					
	20,000 Lumen	158	25.25	27.61	2.35	9.32%
	50,000 Lumen	378	42.58	53.55	10.96	25.75%
	HPS Floodlight					
	22,000 Lumen	84	16.91	15.80	(1.11)	-6.59%
	50,000 Lumen	167	21.77	25.74	3.96	18.21%
	MH Floodlight					
	17,000 Lumen	100	16.09	19.29	3.20	19.88%
	29,000 Lumen	158	18.84	25.09	6.25	33.19%
	Post Top-MV					
	7,000 Lumen	72	15.23	18.76	3.54	23.22%
	Post Top-HPS					
	9,000 Lumen	40	17.32	14.66	(2.66)	-15.36%
	Facilities Charges:					
	Underground circuit per 25 feet over 30 feet	0	0.63	0.63	-	0.00%
SL						
	On Wood Pole					
	7,000 lumen mercury vapor	72	8.71	11.97	3.26	37.44%
	11,000 lumen mercury vapor	100	11.20	15.64	4.44	39.61%
	20,000 lumen mercury vapor	158	14.62	22.25	7.62	52.12%
	50,000 lumen mercury vapor	378	29.25	50.21	20.96	71.66%
	9,000 lumen high pressure sodium	40	8.32	8.03	(0.29)	-3.44%
	16,000 lumen high pressure sodium	59	9.98	10.15	0.17	1.70%
	22,000 lumen high pressure sodium	84	12.42	13.41	0.99	7.97%
	50,000 lumen high pressure sodium	167	18.60	22.73	4.12	22.17%
	9,000 lumen high pressure sodium (post 1988)	40	13.58	14.59	1.01	7.41%
	16,000 lumen high pressure sodium (post 1988)	59	17.04	16.71	(0.33)	-1.92%
	22,000 lumen high pressure sodium (post 1988)	84	19.38	19.98	0.60	3.08%
	50,000 lumen high pressure sodium (post 1988)	167	28.16	29.30	1.15	4.07%
	On Metal Pole:					
	7,000 lumen mercury vapor	72	11.79	15.90	4.12	34.95%
	11,000 lumen mercury vapor	100	14.62	20.34	5.72	39.12%
	20,000 lumen mercury vapor	158	18.26	27.30	9.04	49.49%
	50,000 lumen mercury vapor	378	34.14	55.76	21.62	63.34%
	9,000 lumen high pressure sodium	40	16.64	13.57	(3.07)	-18.44%
	16,000 lumen high pressure sodium	59	18.26	15.67	(2.59)	-14.19%
	22,000 lumen high pressure sodium	84	20.72	18.95	(1.77)	-8.55%
	50,000 lumen high pressure sodium	167	26.88	28.26	1.38	5.15%
	9,000 lumen high pressure sodium (post 1998)	40	43.74	30.88	(12.86)	-29.40%
	16,000 lumen high pressure sodium (post 1998)	59	45.54	33.00	(12.54)	-27.54%
	22,000 lumen high pressure sodium (post 1998)	84	47.99	36.26	(11.74)	-24.46%
	50,000 lumen high pressure sodium (post 1998)	167	54.25	45.58	(8.67)	-15.98%

OHIO POWER COMPANY
Case Nos. 11-346-EL-SSO and 11-348-EL-SSO
Typical Bill Comparison
(Annualized)

Rate Code	Level of Demand (A)	Level of Usage (B)	Current Total Bill (C)	Proposed Total Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)
SL						
	Multiple Lamps on Metal Pole:					
	20,000 lumen mercury vapor	156	16.36	25.01	8.66	52.91%
	9,000 lumen high pressure sodium	40	12.45	10.79	(1.66)	-13.34%
	16,000 lumen high pressure sodium	59	14.10	12.90	(1.21)	-8.55%
	22,000 lumen high pressure sodium	84	16.54	16.18	(0.35)	-2.14%
	50,000 lumen high pressure sodium	167	22.72	25.49	2.77	12.19%
	9,000 lumen high pressure sodium (post 1998)	40	26.19	19.45	(6.74)	-25.73%
	16,000 lumen high pressure sodium (post 1998)	59	27.86	21.56	(6.30)	-22.62%
	22,000 lumen high pressure sodium (post 1998)	84	30.33	24.84	(5.49)	-18.11%
	50,000 lumen high pressure sodium (post 1998)	167	36.58	34.15	(2.43)	-6.65%
	Post Top Unit:					
	7,000 lumen mercury vapor	72	11.71	15.82	4.12	35.19%
	9,000 lumen high pressure sodium	40	14.38	12.08	(2.30)	-16.03%
	9,000 lumen high pressure sodium (post 1988)	40	17.92	13.82	(4.10)	-22.88%
	Facilities Charges:					
	Receptacle Charge	0	2.10	2.10	-	0.00%

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	)	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY OF
LAURA J. THOMAS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed January 27, 2011

INDEX TO DIRECT TESTIMONY OF
LAURA J. THOMAS

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
LAURA J. THOMAS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura J. Thomas. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE INDICATE BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am employed as Managing Director – Regulatory Projects and Compliance in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo), referred to collectively as AEP Ohio, or the Company.

BUSINESS EXPERIENCE

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from The Ohio State University in 1979 with a Bachelor of Science Degree in Mathematics with a Statistics minor. I also received a Master of Science degree in Mathematics from The Ohio State University in 1981. I joined AEPSC in 1982 and held various analyst positions in the rate design and cost of service group over the next several years.

During the period of 1996 through 2003, I held the positions of Director – Pricing and Contracts and Director of Regulated Pricing and Analysis. In May 2003 I was promoted to Vice President – Fuel and Cost Recovery within Commercial Operations. In June 2005, I moved to the risk function where I held the position of Vice President – Enterprise Risk and Insurance with responsibility for American Electric Power's (AEP) enterprise risk oversight process, risk and insurance management, including insurance procurement and claims handling, and oversight of the insurance captive utilized by the Company. Effective March 1, 2010, I moved to the Regulatory Services Department where my responsibilities include special projects related to regulatory issues and compliance.

Q. HAVE YOU EVER SUBMITTED TESTIMONY AS A WITNESS BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified or submitted testimony before regulatory commissions in the states of Indiana, Michigan, Oklahoma, Tennessee, Virginia and West Virginia and before the Federal Energy Regulatory Commission. I have also testified before the Public Utilities Commission of Ohio (Commission) on behalf of CSP and OPCo.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the development of the Market Rate Offer (MRO) prices and comparison to the Company's proposed Electric Security Plan (ESP) generation prices, to support the Company's proposed charges for Provider of Last Resort (POLR), and to address two new riders for the recovery of generation-related facility closure costs and North American Electric Reliability Corporation (NERC) compliance costs.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring Exhibits LJT-1 through LJT-3.

MARKET RATE OFFER PRICE TEST

Q. PLEASE GENERALLY DESCRIBE THE MRO PRICE TEST.

A. I have been advised by counsel that the purpose of the MRO price test is to determine how the Company's proposed ESP in the aggregate compares to the expected prices under an MRO. The expected prices that would otherwise occur under a MRO are determined by a weighting of adjusted prior ESP prices and competitive market prices. My testimony will address how the Company's proposed ESP prices, supported by Company witness Roush, compare to MRO prices during the proposed ESP period. Company witness Hamrock addresses the proposed ESP plan in the aggregate.

Q. PLEASE DESCRIBE THE COMPONENTS NEEDED FOR THE DETERMINATION OF MRO PRICES FOR THE PROPOSED ESP PERIOD.

A. Two components are needed to determine the expected results of an MRO during the proposed ESP period – a Competitive Benchmark price and a generation Standard

Service Offer price (SSO). The Competitive Benchmark price is based on market data and includes the items that would be included by a supplier providing retail electric service to AEP Ohio customers. The generation SSO price is a function of generation pricing from the Company's 2009-2011 ESP adjusted for certain generation-related items.

Q. HOW IS THE COMPETITIVE BENCHMARK DETERMINED?

A. The Company's approach to developing a Competitive Benchmark price is based on industry standards for pricing retail generation supply in the competitive market. I have been advised by counsel that Section 4928.20(J), Ohio Revised Code, provides some general guidance on the items that should be included in the Competitive Benchmark where it discusses the market price for governmental aggregation customers that return to the utility for competitive retail service. The provision states that "...such market prices shall include, but not be limited to"

- Capacity Charges;
- Energy Charges;
- All charges associated with the provision of power supply through the regional transmission organization (RTO), including but not limited to, transmission, ancillary services, congestion, and settlement and administrative charges; and
- All other costs incurred by the utility that are associated with the procurement, provision and administration of that power supply.

Items typically included in the capacity and energy charges for retail customers are basis adjustments, load shape adjustments, distribution losses, retail administration costs and transaction risk adjustments. Consistent with the guidance cited above, ten distinct components have been used to determine the Competitive Benchmark price.

Q. WHAT OTHER INFORMATION WAS REVIEWED FOR DETERMINATION OF THE COMPONENTS OF THE COMPETITIVE BENCHMARK PRICE?

A. States with deregulated electricity markets were reviewed to determine which pricing components are used to set competitive rates in the auctions for generation service. The components for pricing in the states of Delaware, Maryland, New Jersey, Pennsylvania and Illinois were reviewed because these states fall within the PJM footprint and therefore would have comparable RTO requirements for serving load as in Ohio. These states also utilize a competitive bidding or auction process for full requirements service to retail customers and have specified elements to be included in the competitive bid generation prices. In addition, First Energy's competitive bid process used for full requirements SSO service incorporates comparable pricing components. While the names of the components may differ by state or utility, the components are similar to those proposed by the Company for inclusion in the Competitive Benchmark price.

Q. DID THE COMPANY USE THE SAME MARKET PRICE COMPONENTS AS USED IN THE 2009-2011 ESP FOR THE DETERMINATION OF THE MRO?

A. Yes the Company used the same components as in the 2009-2011 ESP with one exception. An Alternative Energy Requirement was added to reflect the requirements that will be, or are anticipated to be, applicable to suppliers in 2012.

Q. WHAT WAS THE COMPANY'S GENERAL APPROACH IN DETERMINING EACH COMPONENT OF THE COMPETITIVE BENCHMARK PRICE?

A. The Company's approach was to develop Competitive Benchmark prices using ten distinct components. Verifiable, publicly available information for each component of the Competitive Benchmark was used wherever possible. Where qualitative data was used, the experiences of various deregulated states were used to reflect a reasonable and balanced approach in determining an appropriate charge. Based on the ten components, Competitive Benchmark prices were developed for the residential, commercial and industrial classes and were then weighted based on mWh to determine total Competitive Benchmark prices for AEP Ohio. Prices were also developed for two periods. The first period was 2012 and the second was the 17-month period for January 2013 through May 2014.

Q. PLEASE DESCRIBE EACH OF THE COMPONENTS OF THE COMPETITIVE BENCHMARK PRICE AND HOW THOSE COMPONENTS WERE DETERMINED.

A. 1. Simple Swap (SS) – this component is the "around the clock" price of the industry standard energy product. It is traded through the broker market and on electronic exchanges and, ideally, prices for the AEP load zone would be selected. However, the nearest liquid trading location where market quotes are available is the AEP-Dayton Hub and therefore this location was used as a proxy for the AEP load zone.

2. Basis Adjustment – this adjustment is based on the historic relationship between pricing points. Applying such an adjustment to the AEP-Dayton Hub SS prices results in prices at the AEP load zone which is where PJM settles all AEP Ohio loads. Such an adjustment would not be required if market quotes were readily available for the AEP load zone.

3. Load Following/Shaping Adjustment – this adjustment, applied to the SS component, accounts for the fact that customers do not use a constant amount of energy across all hours of the day and that customers will deviate from their historic load profile. The calculations are the result of modeling that uses CSP and OPCo hourly class historical load shapes, publicly available PJM market prices and historic volatility.

4. Capacity – this item includes the capacity cost that a CRES (competitive electric retail service) provider would incur to serve a retail customer in AEP Ohio's service territory. The cost reflected in the capacity component is based on the rates provided in AEP Ohio's Initial Comments filed in Case No. 10-2929-EL-UNC on January 7, 2011.

5. Ancillary Services - this component prices the cost of ancillary services required by PJM to serve load in the Company's service territory.

6. Alternative Energy Requirement – Section 4928.64, Ohio Revised Code requires that all suppliers meet certain requirements for the mix of alternative energy resources that must be used to serve load in Ohio. This component reflects the anticipated incremental market cost of meeting that requirement.

7. ARR Credit – this item captures the credit allocated to offset PJM congestion charges. It is based on published, historical values adjusted as necessary for announced transmission upgrades.
8. Losses – this component captures the cost of distribution and fixed transmission losses that must be supplied in order to meet the customer's power requirements at the meter.
9. Transaction Risk Adder – this item reflects a variety of risks that vary based on the unique profile and business objectives of an individual bidder. Examples of supplier risks include commodity price risk, migration risk, counterparty default risk and credit risk.
10. Retail Administration Charge – the component captures the costs that a supplier would incur to participate in an auction and fulfill the contractual obligations in the event the supplier was successful in the auction. The cost of personnel, overhead, taxes, profit, etc. are included and reflect what suppliers would include typically include in their auction bids.

Q. WHAT METHODOLOGY WAS USED TO SELECT THE SS PRICES FROM AVAILABLE MARKET DATA?

A. The SS prices are the standard industry energy product priced at PJM's AEP-Dayton hub. However, the price changes daily and the challenge is to select an appropriate time period to use in selecting the pricing data. To avoid the issue of selecting data that produce a pre-determined result, an average of the forward prices from the first week of each of the three quarters of 2010 were used to develop the SS component of the Competitive Benchmark. This is the same methodology used to select market prices in the Company's 2009-2011 ESP.

Q. DO ALL COMPONENTS OF THE COMPETITIVE BENCHMARK CHANGE DEPENDING ON THE SELECTION CRITERIA FOR THE SS COMPONENT?

A. No. Only the SS, load following/shaping adjustment, losses, and the transaction risk adder will change based on the selection criteria. The remaining components are independent and are not affected by the SS price selection criteria.

Q. WHAT ARE THE RESULTING COMPETITIVE BENCHMARK PRICES BY CLASS AND COMPANY FOR EACH "YEAR" OF THE PROPOSED ESP PERIOD?

A. As shown in the tables below, the weighted average yearly Competitive Benchmark prices are $77.91/mWh for 2012 and $82.90/mWh for Jan 2013 through May 2014.

AEP Ohio Competitive Benchmark Prices by Customer Class ($/mWh)		
	2012	Jan 2013 – May 2014
Residential	88.18	93.20
Commercial	77.94	82.34
Industrial	69.53	74.90
Weighted Average	77.91	82.90

Q. PLEASE DESCRIBE THE GENERATION STANDARD SERVICE OFFER PRICE (SSO).

A. As identified in Section 4928.142 (D), Revised Code, one component of the MRO determination is the Company's "most recent standard service offer price" which may be adjusted for any of four identified cost components. Those four cost components are fuel, purchased power, costs of satisfying supply and demand portfolio requirements for Ohio (renewable and energy efficiency requirements), and costs to comply with environmental laws and regulations.

The Company's "most recent standard service offer price" is the generation rate approved by the Commission for the Company for 2011. Company witness Roush provided and supports that price.

Q. WERE ANY ADJUSTMENTS MADE TO THE 2011 GENERATION PRICE?

A. Yes, for comparability with the Competitive Benchmark, and as permitted by Section 4928.142 D, Ohio Revised Code, adjustments were made to the 2011 generation price that will be billed to customers. The adjustments are detailed below:

1. Because the fuel factors in effect for 2011 will be limited and do not reflect the full cost of fuel according to the provisions of the 2009-2011 ESP, an adjustment was made to reflect the full fuel cost in 2011.
2. As previously discussed for the Competitive Benchmark, there is an annual renewable requirement for any supplier of load in Ohio. Because the impacts of the renewable requirements for 2011 are reflected in the full fuel factor for the year, no further adjustments were made beyond that described above. Failure to include such an adjustment would create a mismatch between the Competitive Benchmark and the adjusted SSO.
3. Other than as needed for compliance with renewable energy requirements, no additional adjustments were made for purchased power.

4. Adjustments were made to reflect the environmental capital investment as part of the SSO. Currently, carrying costs on environmental capital are collected through the Environmental Investment Carrying Costs rider and the underlying costs through 2011 must be included for comparability.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH DETAILS THE CALCULATION OF THE MRO?

A. Yes, Exhibit LJT-2 details those calculations. First, the 2011 SSO is adjusted as described above to create the Total Generation Service Price shown in Line 5 of Exhibit LJT-2. Line 6 shows the results of the development of the Competitive Benchmark which was discussed earlier in this testimony.

As described in Section 4928.142, Ohio Revised Code, these two prices are then weighted for each "year" of the Company's proposed ESP (2012 – May 2014) resulting in the MRO Annual Price shown in Line 11 of Exhibit LJT-2. This MRO Annual Price is the basis for comparison to the Company's proposed prices for the proposed ESP period. Company witness Roush supports the Proposed ESP Prices shown in Line 13 of Exhibit LJT-2.

Q. WHAT WEIGHTINGS ARE APPLIED IN EXHIBIT LJT-2 FOR EACH YEAR OF THE PROPOSED ESP?

A. The weightings used for each year of the proposed ESP prices are summarized in the following table. Even though the Company utilized only two distinct periods for the development of the Competitive Benchmark prices, increased weightings of the Competitive Benchmark were applied each year consistent with the increased weightings set forth in Section 4928.142(D), Ohio Revised Code. For 2012, a weighting of 10% was applied to the Competitive Benchmark price. For the 17-month period of January 2013 – May 2014, a composite weighting of 23% was applied to the Competitive Benchmark price.

Year		Percentage Generation Service Price		Percentage Competitive Benchmark	
2012		90%		10%	
	2013		80%		20%
	Jan-May 2014		70%		30%
Jan 2013 - May 2014		77%		23%	

Q. WHAT ARE THE RESULTS OF THE COMPARISON BETWEEN THE MRO ANNUAL PRICE AND THE COMPANY'S PROPOSED ESP PRICE?

A. As shown in Exhibit LJT-2, the Company's proposed ESP prices compare favorably, in the aggregate, to the weighted average MRO Annual Price. The ESP generation price benefit is shown in Line 13 of Exhibit LJT-2 and shows that there is an overall benefit for the proposed ESP period of $1.41/mWh.

Q. WILL THE MRO PRICE TEST STILL HAVE FAVORABLE RESULTS IF THE COMPETITIVE BENCHMARK PRICE CHANGES?

A. Yes. If the Competitive Benchmark price increases, there will be an even greater benefit from the proposed ESP generation price. If the Competitive Benchmark price decreases, by even as much as 10%, the proposed ESP generation price will still provide a net benefit of zero or greater. As discussed later in this testimony, in addition, the Company's proposed POLR charge must be adjusted for the change in Competitive Benchmark price.

Q. ARE THERE CONSIDERATIONS BEYOND THE DIRECT PRICE COMPARISON OF THE MRO ANNUAL PRICES AND THE COMPANY'S PROPOSED ESP PRICES THAT SHOULD BE NOTED?

A. Yes, there are other considerations. The Competitive Benchmark used in the determination of the MRO Annual Price is a function of market pricing. While the best information available was used in the development of the prices, the market is constantly changing. As discussed above, the Company's methodology for determining the SS component of the Competitive Benchmark was chosen to best recognize the effects of changes in price over a period of time.

An important consideration in the proposed ESP to MRO price comparison is that a movement to MRO pricing is irreversible. Based on advice of counsel, once MRO pricing is in effect, that will continue to be the basis for generation pricing from that point forward.

PROVIDER OF LAST RESORT

Q. PLEASE DESCRIBE THE PROVIDER OF LAST RESORT (POLR) OBLIGATION FOR THE COMPANY.

A. The Company incurs a POLR obligation because all customers are free to switch to receive generation service from a CRES provider, either on an individual basis or as part of governmental aggregation. In addition, customers are free to return to receiving SSO generation service from the Company when they so choose. The Company must then serve such customers whether it is the choice of the customer to return or if the CRES provider or supplier to the governmental aggregation group were to default in its service obligation. Consequently, the Company's generation obligation is subject to significant volatility.

The flexibility or options provided to customers are obligations for the Company who is put in the position of losing customers when the competitive market price is low, but required to stand ready to serve that load again when market prices increase and customers return. There is a definite and significant cost associated with providing customers this flexibility.

Q. IS THE POLR OBLIGATION UNIQUE TO OHIO ELECTRIC DISTRIBUTION COMPANIES?

A. Yes, only Ohio electric distribution utilities incur the POLR obligations and the associated risks regardless of whether or not they are currently serving a customer. CRES providers do not have such obligations and are free to choose the customers they serve, the length of time to provide service, and the pricing and terms and conditions of such service. However, the Company has no such choices and must serve any customer in its service territory that CRES providers choose not to serve or choose to stop serving. Customers have the right to rely on the Company for fixed price generation service and the Company must be appropriately compensated for this option that it is required to provide.

Q. DOES THE COMPANY CURRENTLY HAVE A POLR CHARGE?

A. Yes, the Company currently has a POLR charge as approved by the Commission in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO. However, under the 2009-2011 ESP, customers who select service from a CRES provider have the option to avoid the POLR charge if they agree that upon return to service from the Company, they must pay for generation service at market-based rates. To date, of the customers that have selected service from a CRES provider and receive distribution service from the Company, 97% have elected to continue to pay the POLR charge. Therefore, based on actual customer behavior when faced with this choice, it is clear that customers place value on the option to return to service at SSO generation rates.

Q. DOES HAVING A POLR CHARGE PREVENT CUSTOMERS FROM SWITCHING?

A. No, a POLR charge does not keep customers from shopping. On the contrary, the POLR option provides customers with the option to shop and return to the Company under SSO rates. As approved by the PUCO, the POLR is effectively nonbypassble. When a customer considers shopping, they may either 1) switch suppliers, continue to pay the POLR charge, and retain the right to return to the Company at SSO generation prices or 2) switch suppliers and commit to pay market prices if they return to service from the Company. This is appropriate because only upon a customer commitment to market pricing is the Company partially relieved of its POLR obligation. The term "partial" is used because the Company is still required to serve the customer, only the issue of price has been resolved.

Q. WHY DOES THE COMPANY CONSIDER THE POLR CHARGE TO BE NONBYPASSABLE?

A. The POLR charge is nonbypassable because customers must continue to pay the POLR charge if they want to retain access to SSO generation rates. They will continue to pay the cost of the POLR option to retain that access. However, as discussed above, a customer who switches suppliers may choose to avoid the POLR charge by making an affirmative commitment to take service at market prices should they return to service from the Company.

Q. DOES THE CURRENT LEVEL OF CUSTOMER SWITCHING HAVE AN IMPACT ON THE NEED FOR A POLR CHARGE?

A. No. The Company incurs a POLR obligation regardless of who is currently serving a customer in the Company's service territory because a customer can always return to service by the Company. Further, as discussed below, during the term of the 2009-2011 ESP, customer switching have been increasing significantly in response to increasing market rates. Moreover, customers that have not switched to date could still exercise their shopping right at any time during the proposed ESP.

Q. WHAT IS THE RISK THAT SWITCHING LEVELS WILL CHANGE DURING THE PERIOD OF THE PROPOSED ESP?

A. Even though the current level of switching is not a determining factor regarding the need for a POLR charge, a review of switching trends across the state shows how quickly the level of switching can change. Exhibit LJT-3, Page 1 shows the levels of switching that have occurred for each of the Ohio utilities for the period Q1 2009 through Q2 2010. As shown by the data, the percentage of customer switching can change significantly within a one year period. Considering that the Company is committing to a multi-year ESP period, there is significant POLR risk regardless of the current level of switching at this time.

Exhibit LJT-3, Page 2 shows how the recent level of switching for the Company shows the same developing trend as experienced by the other Ohio utilities.

Q. PLEASE PROVIDE A DESCRIPTION OF THE METHODOLOGY USED TO DETERMINE POLR VALUATION FOR THE COMPANY'S 2009-2011 ESP.

A. The cost of the Company's POLR obligation was determined by using the Black option pricing model that can calculate the value of options on forward contracts. This model provided a method for quantifying the asymmetric risk of the Company's POLR obligation. This approach is appropriate when there is a predetermined exercise price (ESP price) and a fluctuating market price. The main drivers of the cost of the POLR obligation are 1) the distance between the proposed ESP price and the expected market price and 2) the volatility of expected market prices. In 2008, the model variables were:

1. Competitive Benchmark Price (Forecasted Market Price),
2. Proposed ESP Price (Strike Price),
3. Volatility of Competitive Benchmark Prices (Volatility of Market Prices),
4. Length of the Proposed ESP Period (Term), and
5. Risk Free Interest Rate.

Q. WHY IS AN OPTION MODEL THE APPROPRIATE WAY TO VALUE THE COMPANY'S POLR OBLIGATION?

A. The costs of the Company's POLR obligation are best understood by viewing the options of the customer which puts the Company on the opposite side of those options. The customers' option to switch providers is at the economic convenience of the customers. The Company bears the cost of that option regardless of whether or not customers exercise their option. In the event that customers exercise their option there will always be an additional cost to the Company, *i.e.* as the default provider, the Company will always be on the losing end in a market price to SSO comparison.

Q. WHAT METHODOLOGY IS BEING PROPOSED TO VALUE THE COMPANY'S POLR OBLIGATION IN THIS FILING?

A. The Company proposes to use the same basic model as used in the 2009-2011 ESP. However, the model has been revised to quantify the impact of the switching constraints reflected in the Company's current tariffs. It is best to view this methodology as a "constrained option model" relative to the "unconstrained option model" previously used. Both models rely on the same conceptual framework and the same set of model variables. The only difference is the inclusion of the switching constraints, which accordingly reduces the value of the option.

Q. PLEASE DESCRIBE THE SWITCHING RULES (CONSTRAINTS) CONTAINED IN THE COMPANY'S CURRENT TARIFFS.

A. Under the existing tariffs, there are certain provisions regarding when a customer may switch and how long they must stay with the Company if they return to the Company's SSO. The rules are differentiated for residential and small commercial customers versus large commercial and industrial customers. For residential and small commercial customers, if the customer returns to generation service from the Company during the period of May 16 to September 15, they must remain with the Company until the following April 15. Large commercial and industrial customers returning to generation service from the Company must remain with the Company for a period of not less than twelve months. These constraints do not apply to customers who elect to return to service from the Company at market rates.

Q. WHY IS THE VALUATION PRESENTED IN THIS PROPOSED ESP AN APPROPRIATE DETERMINATION OF THE COMPANY'S POLR OBLIGATION?

A. The proposed valuation is appropriate because the option model continues to be the most appropriate method of evaluating the risk associated with a POLR obligation. There are several factors contributing to this conclusion. The model appropriately considers the fixed price commitments proposed by the Company for the proposed multi-year ESP. The approach also recognizes the variation in market prices for generation service because market prices will fluctuate over the ESP period. Customer rights to switch suppliers at the customer's option are recognized by this approach. In addition, the Company has taken steps to incorporate the existing switching constraints, an approach that actually results in a lower POLR valuation than it would otherwise. In all, the Company's approach reflects the items that impact the cost of the Company's POLR obligation.

Q. DOES THE COMPANY'S PROPOSED POLR CHARGE REPRESENT THE COST OF CAPACITY TO SERVE CUSTOMERS?

A. No. Neither the current nor the proposed POLR charge represents the cost of capacity to serve customers. As discussed previously, the POLR charge reflects the cost of providing a customer with switching options, not the cost of capacity and energy to serve the customer. Payment of the POLR charge provides the customer a benefit by having a fixed price option for capacity and energy for default service instead of market-based pricing for default generation service. However, the customer has the choice of not paying the POLR charge which then entitles the customer to only market-based default generation service.

In addition, the Company's proposed ESP generation rates are the rates that the Company will charge for capacity and energy to a customer served by the Company. If a customer selects a CRES provider, then the customer no longer pays the Company for capacity and energy, but pays the CRES provider for these services instead.

A customer receiving generation service from the Company pays only once for capacity and energy – through the ESP generation rates. A customer receiving service from a CRES provider does not pay the Company for capacity and energy because they do not pay the Company's ESP generation rates. All customers pay a POLR charge in order to maintain the option to receive fixed price service. However, if a customer chooses a CRES provider, they have the opportunity to waive paying the POLR charge which eliminates that option in exchange for being subject to market-based rates upon any return to service from the Company.

Q. PLEASE DESCRIBE THE RESULTS OF THE COMPANY'S POLR VALUATION.

A. Based on the methodology described above for the "unconstrained option model", the Company's proposed POLR charge would be $3.20/MWH for the proposed ESP period. However, as discussed above, the Company has updated its model to incorporate the impact of the current switching rules (constraints) which reduces the proposed POLR to $2.84/MWH based on the "constrained option model."

Q. PLEASE DESCRIBE THE COMPANY'S POLR PROVISIONS FOR THE PROPOSED ESP THAT CORRESPOND WITH THE PROPOSED POLR VALUATION.

A. Under the Company's proposed ESP, customers who chose an alternative supplier under the 2009-2011 ESP and who committed to pay market prices if they return to service from the Company must continue that obligation if they return to the SSO during the proposed ESP term. It was the customers' choice to avoid the POLR charge, but that avoidance was tied to a commitment that must be honored by the customers. If customers are relieved of that commitment, then the proposed POLR charges will need to be adjusted.

Q. SHOULD THE CUSTOMER'S COMMITMENT BE LIMITED TO THE LENGTH OF THE COMPANY'S PROPOSED ESP?

A. No. The customer's commitment to market pricing should extend beyond the term of the proposed ESP. This is consistent with the overall movement to market pricing in Ohio.

Q. ARE THERE WAYS TO MITIGATE THE COST OF THE POLR OBLIGATION?

A. Generally, the more options that customers have to switch back and forth from the Company, the greater the cost of the POLR obligation. In the event that additional switching restrictions might be imposed, these could reduce the cost of the POLR obligation. While no additional switching restrictions are being proposed at this time, the Company's proposed constrained model approach could be adjusted to reflect additional switching restrictions producing a corresponding lower POLR cost.

Conversely, if switching constraints are removed, then the cost of the Company's POLR obligation increases.

Q. PLEASE DESCRIBE HOW THE POLR CHARGES ARE AFFECTED BY THE USE OF THE PROPOSED ESP AND THE COMPETITIVE BENCHMARK PRICES.

A. The POLR model uses inputs whose many components are shared by both the proposed ESP price and the Competitive Benchmark price. However, this does not mean that the resulting POLR valuation is a mechanism for the recovery of costs of those specific components. In the model, it is not the absolute values of these two prices, but rather the difference between the two prices that is a key driver in determining the POLR value. The smaller the difference, *i.e.*, the closer the ESP price is to the Competitive Benchmark price (market), the more likely customers are to exercise the option to migrate between known ESP rates and the varying market price, and therefore results in a greater POLR value.

Q. BECAUSE THE ESP RATES, COMPETITIVE BENCHMARK PRICE AND SWITCHING RULES ARE INPUTS TO THE POLR MODEL, WHAT IS THE COMPANY'S PROPOSAL FOR FINAL POLR CHARGES?

A. The Company proposes that the Commission approve its POLR methodology as set forth in this testimony. Once the ESP rates, Competitive Benchmark prices and switching rules become final in this proceeding, the Company will provide the final (compliance) POLR charges based on that methodology.

FACILITY CLOSURE COST RECOVERY RIDER

Q. DOES THE COMPANY ANTICIPATE THAT THERE MAY BE GENERATION-RELATED FACILITY CLOSURES DURING THE PROPOSED ESP PERIOD?

A. Yes. It is very likely that some generation-facilities will close during the proposed ESP period and there are many reasons for such potential closures. First, some facilities might close due to their age and/or planned retirement. Units may also close to fulfill commitments made by the Company as part of the AEP New Source Review (NSR) consent decree. Premature or early retirements of facilities may occur due to operational, safety, or economic reasons. However, the potential for closure is more likely due to comply with new environmental requirements where emissions controls may be uneconomic.

Q. IS THE COMPANY ABLE TO DETERMINE EXACTLY WHICH FACILITY CLOSURES WILL OCCUR DURING THE PROPOSED ESP PERIOD?

A. No. The evolution of environmental requirements is uncertain; the only certainty is that more environmental requirements are on the horizon and that they will be more stringent. However, the timing for compliance with new rules is unknown. This uncertainty and the impact it will have on Ohio's utilities was recognized by the Commission in its comments filed with the EPA on the proposed Transport Rule in Docket No. EPA-HQ-OAR-2009-0491. Regarding the impact on customer rates, the Commission stated:

> "The proposed rule, in concert with anticipated rules, will accelerate the retirement of coal fired electric generating plants. The cost of premature retirements will have a direct impact on rates, not only as a result of necessary amortization and

> closure costs....Compounding this concern is the consideration that many of the electric distribution utilities that may be negatively impacted, as discussed above, serve as Provider of Last Resort (POLR) to our native load customers." (PUCO comments, page 6)

The Commission provided similar comments in its filing with the EPA on the proposed Coal Combustion Residuals Rule in Docket No. EPA-HQ-RCRA-2009-0640. Depending upon the outcome of this proposed rule, the cost of closing an ash pond could vary considerably.

Q. WHAT TYPES OF COSTS IS THE COMPANY LIKELY TO INCUR RELATED TO FACILITIES THAT CLOSE DURING THE PROPOSED ESP PERIOD?

A. For facilities that close during the proposed ESP period, closure costs are expected to fall into several categories, however the categories and levels of costs will depend on the specific facility. Such categories could include, but are not limited to, materials and supplies unique to the facility, environmental liabilities requiring action upon facility closure, mitigation costs required by applicable existing or future environmental regulations, and legacy pension and benefit requirements. For facilities requiring early closure, costs may also include undepreciated balances. The Company would offset such costs with any salvage or proceeds related to the plant assets, unique materials and supplies, etc.

Q. IS THE COMPANY ABLE TO DETERMINE THE CLOSURE COSTS FOR SPECIFIC FACILITIES AT THIS TIME?

A. No. Even for facilities that the Company may be able to determine a closure date, the total closure cost of a facility will be affected by the applicable environmental rules and therefore the Company is unable to determine the total cost. If the Company was able to determine the cost at this time, it would be included in the Company's proposed ESP prices. For this reason, the Company proposes a rider where actual costs, net of salvage or other related proceeds, would be submitted on an annual basis for review and recovery in the subsequent year. This rider would be applicable to the actual closure costs for any generation-related facility closed during the period of the proposed ESP.

Q. WOULD A RIDER FOR THE RECOVERY OF FACILITY CLOSURE COST BE CONSISTENT WITH THE IMPACT OF POTENTIAL ENVIRONMENTAL RULES?

A. Yes. As recognized by the Commission in its comments to the EPA, the Company would be negatively impacted by such rules that accelerate the retirement of its plants used to provide POLR service. Other rules that impact closure costs, even if they don't result in early retirements, will have the same negative impact. Accordingly, these types of rules will increase the costs of providing SSO service for which the Company is committing to fixed price service during the proposed ESP. Since such fixed prices do not include closure costs that the Company would incur during the proposed ESP period, a rider mechanism is required.

Q. HOW WILL THIS RIDER BE STRUCTURED?

A. Company witness Moore will address the structure of this rider.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL REGARDING THE ACTUAL CLOSURE OF THE FACILITIES DESCRIBED ABOVE.

A. As part of the proposed ESP, the Company requests that Commission pre-approve the closure of any such facilities during the ESP that the Company has determined to be uneconomic to continue to operate.

GENERATION NERC COMPLIANCE COST RECOVERY RIDER

Q. PLEASE DESCRIBE WHAT IS MEANT BY GENERATION NERC COMPLIANCE COSTS.

A. In accordance with the Federal Power Act of 2005, FERC designated NERC as the electric reliability organization responsible for establishing and implementing standards to ensure the reliability of the bulk electric system. The result has been an increasing number of compliance requirements that the Company has been required to address. There are numerous activities under NERC's purview that continue to create additional requirements for the Company. FERC also supports these efforts as evidenced by FERC's September 16, 2010 statement acknowledging 120 action items that NERC will implement. New standards are constantly being developed and many are already being discussed for proposal. Finally, interpretations of the existing standards by NERC, the reliability entities and their auditors continue to evolve, often resulting in additional efforts for compliance

Q. ARE ALL NERC COMPLIANCE COSTS GENERATION RELATED?

A. No. Many of such costs are transmission related. However, there are existing mechanisms by which transmission-related compliance costs are required. No such mechanism currently exists for incremental generation-related compliance costs.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER SUCH GENERATION-RELATED COMPLIANCE COSTS

A. The Company proposes to utilize a nonbypassable rider to recover such costs. These costs are not a function of the Company's load or the customers they serve. However, because the Company owns physical generation facilities, it is subject to compliance requirements.

Q. HOW WILL THIS RIDER BE STRUCTURED?

A. Company witness Moore will address the structure of this rider.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

AEP Ohio
Electric Security Plan
Competitive Benchmark Prices by Component and Customer Class

2012				
$/mWh				
		Residential	**Commercial**	**Industrial**
1	Simple Swap	40.59	40.59	40.59
2	Basis Adjustment	0.58	0.58	0.58
3	Load Following/Shaping Adjustment	6.54	3.17	2.77
4	Capacity	28.49	23.03	16.28
5	Ancillary Services	0.60	0.60	0.60
6	Alternative Energy Requirement	0.54	0.54	0.54
7	ARR Credit	(1.40)	(1.06)	(0.93)
8	Losses	3.04	1.78	0.79
9	Transaction Risk Adder	4.20	3.71	3.31
10	Retail Administration	5.00	5.00	5.00
	Class Total	88.18	77.94	69.53
	Weighted Total		77.91	

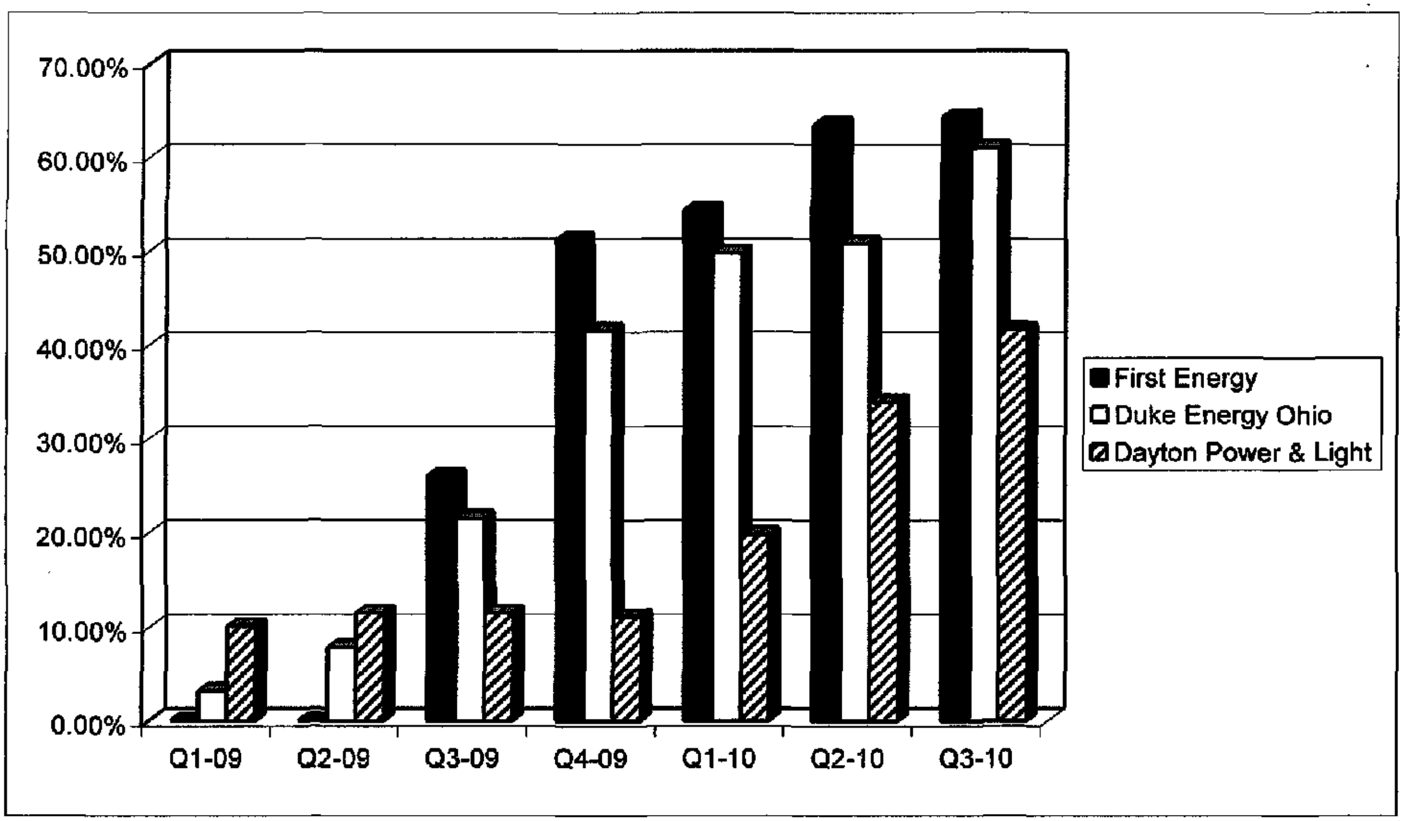
Jan 2013 - May 2014				
$/mWh				
		Residential	**Commercial**	**Industrial**
1	Simple Swap	45.06	45.06	45.06
2	Basis Adjustment	0.58	0.58	0.58
3	Load Following/Shaping Adjustment	6.50	3.09	2.95
4	Capacity	28.31	22.40	16.40
5	Ancillary Services	0.60	0.60	0.60
6	Alternative Energy Requirement	0.79	0.79	0.79
7	ARR Credit	(1.40)	(1.05)	(0.92)
8	Losses	3.32	1.95	0.87
9	Transaction Risk Adder	4.44	3.92	3.57
10	Retail Administration	5.00	5.00	5.00
	Class Total	93.20	82.34	74.90
	Weighted Total		82.90	

AEP Ohio
Electric Security Plan
Market Rate Option Test

	Generation Service Price	2012 (1)	Jan 2013 - May 2014 (2)	Wtd Average (3) = weighted (1) and (2)
1	2011 Base ESP 'g' Rate	23.15	23.07	23.10
2	2011 Full Fuel*	32.86	32.86	32.86
3	2011 Environmental Compliance Costs **	0.90	0.90	0.90
4	Total Generation Service Price	56.91	56.82	56.86
	Expected Bid Price			
5	Competitive Benchmark	77.91	82.90	80.83
	MRO Pricing			
6	Generation Service Price	56.91	56.82	56.86
7	Generation Service Weight	90%	77%	
8	Expected Bid Price	77.91	82.90	80.83
9	Expected Bid Weight	10%	23%	
10	MRO Annual Price	59.01	62.82	61.23
	MRO - ESP Price Comparison			
11	MRO Annual Price	59.01	62.82	61.23
12	Proposed ESP Price	58.42	60.82	59.82
13	ESP Price Benefit	0.59	2.00	1.41

* Includes "Renewable and Energy Efficiency Adjustment"
** Assumes no lag in recovery or 2009-2011 carrying costs

AEP Ohio
Electric Security Plan
Percentage of Load Served by Competitive Suppliers
Ohio Utilities



AEP Ohio
Electric Security Plan
Percentage of AEP Ohio Load Served by Competitive Suppliers