COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**Case No. 2017-00179**

DIRECT TESTIMONY OF

ROGNESS, ROSS, SHARP, VAUGHAN, WALSH, WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 4 OF 4

June 28, 2017

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

JOHN A ROGNESS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, John A Rogness III, being duly sworn, deposes and says he is the Director Regulatory Services for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

John A Rogness III

COMMONWEALTH OF KENTUCKY)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John A Rogness III, this the 22nd day of June 2017.

Judy K Rosquist
Notary Public

Notary ID Number: 571144

My Commission Expires: January 23, 2021

DIRECT TESTIMONY OF
JOHN A ROGNESS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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**DIRECT TESTIMONY OF
JOHN A ROGNESS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A. My name is John A. Rogness. My position is Director, Regulatory Services for Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science in Economics from the University of Chattanooga in 1980, a Master of Science in Economics from Vanderbilt University in 1984 and a Ph.D. in Economics from the University of Kentucky in 1991.

In January 1990, I began working in the Kentucky Office of Financial Management and Economic Analysis. From July 1991 – September 1998, I served as an Economist with the Kentucky Public Service Commission (KPSC). From September 1998 – July 2010 I served as Manager of the Management Audit Branch at the KPSC. From August 2010 – September 2012 I served as the Director of the Financial Analysis Division at the KPSC. From October 2012 – March 2014, I served as the Director, Energy Generation, Transmission and Distribution at the Department for Energy

Development and Independence in Kentucky's Energy and Environment Cabinet. On March 17, 2014, I began my duties as Director of Regulatory Services for Kentucky Power Company.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, REGULATORY SERVICES?

A. As Director of Kentucky Power's Regulatory Services, I am responsible for the rate and regulatory matters of Kentucky Power. This includes the preparation and coordination of the Company's testimony and exhibits in rate cases and any other formal filings before this Commission. In addition, I am responsible for assuring the proper application of the Company's rates and tariffs.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I filed testimony and testified in the Company's last base rate case, Case No. 2014-00396, and in the six most recent reviews of the operation of the Company's fuel adjustment clause (FAC), Case Nos. 2014-00225, 2014-00450, 2015-00232, 2016-001, 2016-00230, and 2017-00001. I also filed testimony in the Economic Development Rider proceeding, Case No. 2014-00336; the Company's request for a deviation from certain transmission line inspection requirements, Case No. 2014-00479; the Company's refund deviation proceeding, Case No. 2015-00364; the Company's Big Sandy Ash Pond closure proceeding, Case No. 2015-00152; and the Company's last two demand-side-management proceedings, Case Nos. 2015-00271, 2016-00281.

III. PURPOSE OF YOUR TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is first to present certain revenue and operating expense adjustments to test year values. Second, I address the recovery of purchased power fuel costs excluded from recovery through Kentucky Power's fuel adjustment clause (FAC). Third, I address the inclusion of 37 fuel-related PJM billing line item charges and credits in base fuel and the subsequent recovery (or credit) of variations of those amounts through the fuel adjustment clause. As part of this discussion I also address the reasonableness of amending Kentucky Power's Tariff F.A.C. to recognize monthly variations in the 37 billing line items. Finally, I address the recovery of the gains or losses from incidental gas sales.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I identify the exhibits that I am sponsoring throughout my testimony and list them below:

- Exhibit JAR-1: Fuel Over / Under Recovery Of Fuel Cost
- Exhibit JAR-2: PPA Expense Over / Under Recovery
- Exhibit JAR-3: Handouts From Billing Line Item Informal Meeting
- Exhibit JAR-4: Updated Fuel Adjustment Clause Forms

Q. WERE THESE SCHEDULES AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

IV. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE IDENTIFY EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. I am sponsoring the following adjustments:

Adjustment	Exhibit 2, Page No.
1. Fuel Over Under Synchronization Adjustment	W7
2. PPA Rider Synchronization	W9
3. Rate Case Expense	W19
4. Annualization of Lease Costs	W22
5. Removal of Billing Line Item Expense	W25
6. Coal Stock Adjustment	W51

The details of the revenue and operating expense adjustments are set forth in Section V, Exhibit 2.

Fuel Over Under Synchronization Adjustment
Section V, Exhibit 2, W7

Q. PLEASE EXPLAIN THE ADJUSTMENTS PROPOSED IN CONNECTION WITH THE OVER/UNDER RECOVERY OF FUEL COSTS.

A. During the test year, the Company collected jurisdictional revenues of $158,106,513 and experienced jurisdictional fuel costs of $162,680,985. Deferred Fuel Cost is eliminated from the adjustment in order to match actual fuel revenues with actual fuel costs for a total test year level difference of $4,574,472. To design rates to recover the appropriate level of revenue, test year revenues should be increased by $4,574,472. This adjustment trues up the fuel clause revenues with the actual fuel clause expense. Please see Exhibit JAR-1 for supporting calculations.

PPA Rider Synchronization
Section V, Exhibit 2, W9

Q. PLEASE EXPLAIN THE REMOVAL OF PPA EXPENSE FROM BASE RATES.

A. During the test year, the Company collected retail revenues of $448,154 through Tariff PPA, but incurred expenses that are recoverable through Tariff PPA of $820,696. The Company adjusted test year Tariff PPA revenues to synchronize revenues with recoverable costs. This synchronization results in an increase in revenue requirement of $372,542. The calculations supporting this adjustment are included in Exhibit JAR-2.

Rate Case Expense
Section V, Exhibit 2, W19

Q. WHAT IS THE RATE CASE EXPENSE ADJUSTMENT?

A. The Company is allowed to recover the reasonable expenses of the preparation and litigation of this rate case proceeding, including reasonable consulting and legal expenses. The test year includes rate case expenses totaling $81,734. The Company estimates a total rate case expense of $1,375,000. Amortizing total rate case expenses over three years and subtracting actual test year expenses yields a test year expense adjustment of $376,599.

Annualization of Lease Costs
Section V, Exhibit 2, W22

Q. PLEASE EXPLAIN THE LEASE COST ADJUSTMENT.

A. In this adjustment the decrease of $40,146 reflects the annualized difference between the current annual level of lease costs based on February 2017 total lease rental expenses of $1,522,666 and the test year lease costs of $1,562,287. As such, the decrease represents a known and measurable change in Kentucky Power Power's expenses.

Removal of PJM Billing Line Items
Section V, Exhibit 2, W25

Q. PLEASE EXPLAIN THE REMOVAL OF PJM BILLING LINE ITEMS FROM BASE RATES.

A. As described below in Section VI, the Company is proposing to recover the charges and credits associated with an additional 37 fuel-related PJM billing line items through the FAC. Accordingly, the Company is removing the charges and credits associated with those 37 billing line items from non-fuel test year expenses. This adjustment removes a net $516,659 in test year billing line item expenses from base rate expense.

Coal Stock Adjustments
Section V, Exhibit 2, W51

Q. WHY ARE COAL STOCK ADJUSTMENTS NECESSARY?

A. The Coal Stock Adjustment adjusts the coal pile investment at the Mitchell Plant to the supply level allowed for recovery. The supply level requested is based on many factors, including the means of transportation to the plant and the location of the supplier in relation to the plant. For the Mitchell Plant the necessary supply level is 30 days for low sulfur coal and 15 days for high sulfur coal. The effect of this adjustment is to reduce Kentucky Power's Materials and Supplies – Fuel Stock working capital by $6,709,111.

V. FUEL ADJUSTMENT CLAUSE

A. Purchased Power Exclusions Due To The Peaking Unit Equivalent Analysis

Q. DOES THE COMPANY RECOVER ALL REASONABLE PURCHASED POWER COSTS THROUGH THE FUEL ADJUSTMENT CLAUSE?

A. No. Prior Commission interpretation of 807 KAR 5:056 held that it excluded from recovery through the FAC two types of purchased power costs: those associated with forced outages and those not associated with forced outages but whose cost exceeds the cost of the Company's highest cost generation units. Subsequently, in Case No. 2000-00495B,[1] the Company received approval to use the Peaking Unit Equivalent as one of the determinants of its highest cost generation unit.

Q. PLEASE EXPLAIN THE PEAKING UNIT EQUIVALENT AND ITS PURPOSE.

A. The Peaking Unit Equivalent refers to the cost per MWh of a hypothetical simple cycle natural gas combustion turbine (CT). Since the Company does not own or operate CTs, the hypothetical Peaking Unit Equivalent is used by the Company as one of the generation cost benchmarks in order to determine on an hourly basis whether a power purchase was made on an economic basis. The calculated cost of the hypothetical CT is used in conjunction with the cost of the Company's other generation units to determine whether purchased power is an economic purchase. The purchased power cost is deemed to be economic and recoverable through the FAC if the purchased power price is less than the cost of the Company's highest cost generation unit including the hypothetical CT.

Q. IS THE PUE CALCULATION REPRESENTATIVE OF THE COST OF OPERATING A SIMPLE CYCLE COMBUSTION TURBINE?

A. No. See Company Witness Vaughan Testimony for a detailed explanation of adjusting the Peaking Unit Equivalent calculation to be more representative of operating a simple cycle combustion turbine.

Q. IS THE COMPANY RECOVERING ITS PURCHASED POWER FUEL COSTS NOT RELATED TO FORCED OUTAGES THAT HAVE BEEN EXCLUDED FROM RECOVERY THROUGH THE FAC?

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[1] See Case No. 2000-00495B, An Examination By The Public Service Commission Of The Application Of The Fuel Adjustment Clause Of American Electric Power Company From May 1, 2001 To October 31, 2001, Order dated October 3, 2002.

A. No. Currently, the Company is not recovering that portion of purchased power costs not related to forced outages that have been excluded from recovery through the FAC. See Company Witness Vaughan Testimony for a detailed explanation of the Company's proposal to recover these costs through a combination of base rates and differences between base and current period amounts.

B. <u>PJM Billing Line Items And Proposed Changes To Billing Line Items Recovered Through The Company's Fuel Adjustment Clause</u>

Q. PLEASE DESCRIBE PJM BRIEFLY.

A. PJM Interconnection, LLC is a Regional Transmission Organization that acts as an independent party in the operation of a competitive wholesale electricity market. PJM also manages the high voltage electricity transmission grid to coordinate the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, and to ensure the reliability of the bulk power system for its members. A more complete description of PJM may be found at www.pjm.com. Kentucky Power and the other AEP East operating companies (Appalachian Power Company, Indiana Michigan Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company) are members of PJM.

Q. PLEASE DESCRIBE HOW THE COMPANY OPERATES WITHIN PJM.

A. Kentucky Power has been a member of PJM since 2004. Within PJM, Kentucky Power is a generation owner, a load serving entity (LSE), and a transmission owner. As a generation owner, the Company bids its available units into the day ahead market. If the unit costs are less than or equal to the market clearing price, and the units are accepted to run the next day, the Company's available generation is economically dispatched (sold) into PJM's energy markets. As an LSE, Kentucky Power purchases its energy and ancillary service requirements from the same markets. Also as an LSE, Kentucky Power utilizes the PJM transmission system to purchase and deliver energy to its internal customers. Kentucky Power compensates PJM for those transmission services. As a transmission asset owner Kentucky Power receives revenues from PJM for the use of its transmission assets. Finally, each month the Company receives a statement from PJM reflecting its charges and credits for the prior month and any adjustments of past charges and credits. These billing line items are both fuel and non-fuel related. Those that are fuel related are discussed further below.

Q. HAS KENTUCKY POWER ADDRESSED PJM BILLING LINE ITEMS AND THEIR RELATION TO THE OPERATION OF THE COMPANY'S FUEL ADJUSTMENT CLAUSE OUTSIDE A FORMAL COMMISSION PROCEEDING?

A. Yes. On January 29, 2016 the Company attended an Informal Meeting at the Commission's offices. The Company and the other utilities in attendance[2] provided handouts listing and describing the PJM billing line items. The handouts were Billing Line Items – Uniform Recovery; Billing Line Items – Non-Uniform Recovery; Additional Billing Line Items – Eligible; and Additional Billing Line Items – Not Eligible.[3] See Exhibit JAR – 3 for the handouts provided at the January 29, 2016

[2] In addition to Company personnel and Commission Staff, the meeting was attended by representatives of Duke Energy Kentucky Inc., East Kentucky Power Cooperative Corporation, Inc., Big Rivers Electric Corporation, the Attorney General's office and the Kentucky Industrial Utility Customers. The purpose was to discuss broadly the uniform treatment of PJM billing line items to be recovered through the FAC in accordance with 807 KAR 5:056. The meeting focused on a description of the billing line items and how each is related to electric generation and hence, fuel consumption.

[3] The 27 PJM billing line item charges and credits listed on the spreadsheet associated with the final handout, Additional Billing Line Items – Not Eligible, are not fuel-related charges and credits and hence not recoverable through the FAC. Kentucky Power does not seek to include the costs and credits associated with these billing line

meeting. The billing line items listed and described in the Billing Line Items – Uniform Recovery; Billing Line Items – Non-Uniform Recovery; Additional Billing Line Items – Eligible handouts are fossil-fuel related and the subject of the discussion below.

1. <u>807 KAR 5:056 And The PJM Billing Line Items Currently Reflected In The Company's Fuel Adjustment Clause</u>.

Q. UNDER 807 KAR 5:056 ONLY FUEL COSTS ARE RECOVERABLE THROUGH A UTILITY'S FUEL ADJUSTMENT CLAUSE. DO ANY PJM BILLING LINE ITEMS REFLECT FUEL-RELATED CHARGES AND CREDITS?

A. Yes. The 44 PJM billing line items listed in Table 1 below are fuel related charges and credits. The service functions represented by these billing line items either require generation resources to be running and online or are associated with billing line items requiring generation resources to be running and online.

Q. WHAT DOES THE TERM "ASSOCIATED WITH BILLING LINE ITEMS REQUIRING GENERATION RESOURCES TO BE RUNNING AND ONLINE" MEAN?

A. The term "associated with billing line items requiring generation resources to be running and online" refers to select billing line items such as the Reconciliation billing line items (1400's) and Financial and Auction Transmission Rights billing line items (1500, 2500, 2510). As explained further below, these billing line items are directly related to other billing line items that require generation resources to be running and online, i.e. consuming fuel. The reconciliation billing line items are true ups of past PJM charges and credits. While financial in nature, the Financial and Auction Transmission Rights

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items in its base fuel expense or to recover (or credit) variations in these billing line items from base fuel amounts through its fuel adjustment clause.

billing line items are directly related to transmission congestion and, to holders of network and firm point to point transmission customers, the net proceeds serve as offsets to congestion charges.

Table 1

PJM Billing Line Items		Currently Recovered By		
No.	Description	Kentucky Power	East Kentucky Power	Duke Kentucky
1200	Day-ahead Spot Market Energy	X	X	X
1205	Balancing Spot Market Energy	X	X	X
1220	Day-ahead Transmission Losses	X	X	X
1225	Balancing Transmission Losses	X	X	X
1420	Load Reconciliation Transmission Losses	X	X	
2220	Transmission Losses Credit	X	X	
2420	Load Reconciliation for Transmission Losses	X	X	
1210	Day-ahead Transmission Congestion		X	X
2210	Transmission Congestion Credit		X	
1215	Balancing Transmission Congestion		X	X
1218	Planning Period Congestion Uplift		X	
2217	Planning Period Excess Congestion Credit		X	
2218	Planning Period Congestion Uplift Credit		X	
1230	Inadvertent Interchange		X	
1250	Meter Error Correction		X	
1260	Emergency Energy		X	
2260	Emergency Energy Credit		X	
1370	Day-ahead Operating Reserve Charge		X	
2370	Day-ahead Operating Reserve Credit		X	X
1375	Balancing Operating Reserve		X	
2375	Balancing Operating Reserve Credit		X	X
1400	Load Reconciliation for Spot Market Energy			
1410	Load Reconciliation for Transmission Congestion			
1430	Load Reconciliation for Inadvertent Interchange			
1478	Load Reconciliation for Balancing			

	Operating Reserve			
1340	Regulation and Frequency Response Service Charge			
2340	Regulation and Frequency Response Service Credit			
1460	Load Reconciliation for Regulation and Frequency Response Service			
1350	Energy Imbalance Service Charge			
2350	Energy Imbalance Service Credit			
1360	Synchronized Reserve Charge			
2360	Synchronized Reserve Credit			
1470	Load Reconciliation for Synchronized Reserve			
1377	Synchronous Condensing Charge			
2377	Synchronous Condensing Credit			
1480	Load Reconciliation for Synchronous Condensing			
1378	Reactive Services Charge			
2378	Reactive Services Credit			
1490	Load Reconciliation for Reactive Services			
1500	Financial Transmission Rights Auction			
2500	Financial Transmission Rights Auction			
2510	Auction Revenue Rights			
1930	Generation Deactivation Charge			
2930	Generation Deactivation Credit			

Q. IS EACH OF THE 44 BILLING LINE ITEMS LISTED IN TABLE 1 ABOVE A CHARGE?

A. No. Billing Line Item numbers that begin with a "2" are credits. Those billing line items beginning with a "1" are charges.

Q. DOES KENTUCKY POWER'S FUEL ADJUSTMENT CLAUSE CURRENTLY REFLECT ANY OF THE 44 PJM BILLING LINE ITEM CHARGES OR CREDITS LISTED IN TABLE 1?

A. Yes. Table 1 lists the seven PJM billing line items currently included in Kentucky Power's base fuel costs. Monthly variations in these costs and credits are recovered (or credited) by Kentucky Power through its fuel adjustment clause.

Q. PLEASE EXPLAIN THE FUEL- RELATED NATURE OF THE SEVEN PJM BILLING LINE ITEMS LISTED IN TABLE 1 ABOVE THAT CURRENTLY ARE REFLECTED AT LEAST IN PART IN THE COMPANY'S FUEL ADJUSTMENT CLAUSE.

A. Billing Line Item numbers 1200 and 1205 reflect fuel-related charges associated with energy purchases in the day ahead spot market and balancing spot market. Billing Line Item numbers 1220, 1225, 1420, 2220, and 2420 reflect fuel-related charges and credits associated with transmission line losses. In Case No. 2007-00522, the Company requested that the Commission approve the recovery of PJM marginal transmission line loss charges and credits through its fuel adjustment clause. The Commission agreed that these changes are the "same types of costs" that were previously included in the Company's FAC in its Order dated June 12, 2007.[4]

Q. ARE THE FEBRUARY 28, 2017 TEST YEAR AMOUNTS OF THE 37 PJM BILLING LINE ITEMS CURRENTLY INCLUDED IN KENTUCKY POWER'S BASE RATES AS PART OF THE COMPANY'S NON-FUEL EXPENSE?

A. Yes. None of the 37 billing line items are included in base fuel expenses. As a result, variations in these amounts are not recovered or credited through the Company's fuel adjustment clause.

[4] See Case No. 2007-00522, An Examination Of The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From May 1, 2007 Through October 31, 2007 at page 6.

2. Kentucky Power's Proposal To Amend The Operation Of Its Fuel Adjustment Clause.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL WITH RESPECT TO THE 37 PJM BILLING LINE ITEMS LISTED IN TABLE 1 THAT ARE NOT CURRENTLY INCLUDED IN THE COMPANY'S BASE FUEL COSTS NOR REFLECTED IN KENTUCKY POWER'S FUEL ADJUSTMENT CLAUSE.

A. Kentucky Power is requesting that the credits and charges associated with the billing line items listed in Table 1 that are not currently reflected in the Company's fuel adjustment clause be removed from its *non-fuel* base expenses and added to the Company's *fuel* base costs. Deviations from fuel base rate amounts then would be collected or credited through the Company's monthly FAC.

Q. BEFORE DISCUSSING THE 37 BILLING LINE ITEMS LISTED IN TABLE 1 IN MORE DETAIL, PLEASE PROVIDE THE COMMISSION WITH AN OVERVIEW OF THESE 37 BILLING LINE ITEMS AND THE BASIS FOR THE COMPANY'S PROPOSAL TO INCLUDE THEIR TEST YEAR AMOUNTS IN THE COMPANY'S BASE FUEL EXPENSE.

A. Each of the 37 billing line items reflects fuel-related charges and credits and as such are properly included in Kentucky Power's base fuel expense. All of the service functions represented by the PJM charges and credits either correspond to or are related to fuel-related services previously received by Kentucky Power as a member of the AEP EAST Pool when the AEP EAST Pool served as a stand-alone balancing authority. As such, the charges and credits associated with these services provided by the AEP East Pool previously were part of the Company's base fuel costs. Monthly variations in these charges were recovered (or credited) through the FAC. In addition, 14 of these billing line items have either been approved by the Commission for recovery through other Kentucky jurisdictional utilities' fuel adjustment clauses or relate directly to billing line items that have been approved by the Commission for recovery through the fuel adjustment clauses of other Kentucky jurisdictional utilities. The February 28, 2017 test year amounts of these 37 billing line items are currently included in the Company's base non-fuel expenses.

The 37 billing line items not currently reflected in the Company's base fuel expense fall into five groups:

- ► Congestion Service-Related Fuel Costs (billing line item numbers 1210, 2210, 1215, 1218, 2217, 2218)
- ► Congestion Hedging-Related Costs (billing line item numbers 1500, 2500, 2510)
- ► Ancillary Service-Related Fuel Costs (billing line item numbers 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1930, 2390)
- ► Miscellaneous Service-Related Fuel Costs (billing line item numbers 1230, 1250, 1260, 2260, 1370, 1375, 2370, and 2375).
- ► Reconciliation billing line items (billing line item numbers 1400, 1410, 1430, 1478).

(a) Congestion Service-Related Fuel Costs And Credits.

Q. PLEASE EXPLAIN WHY THE CONGESTION SERVICE-RELATED FUEL COSTS (PJM BILLING LINE ITEM NUMBERS 1210, 2210, 1215, 1218, 2217, 2218) CONSTITUTE FUEL CHARGES AND CREDITS THAT SHOULD BE

REFLECTED IN BASE FUEL AND RECOVERABLE THROUGH THE COMPANY'S FUEL ADJUSTMENT CLAUSE.

A. Congestion arises when one or more constraints inhibit the economic dispatch of electric energy from serving load. To relieve congestion on the transmission system, generating units are dispatched out of economic order to relieve the congestion. The increased energy costs due to the re-dispatch to relieve congestion are reflected in the congestion price component of the locational marginal price ("LMP") and assessed to market participants such as Kentucky Power. These increased energy expenses, like energy purchased to serve Kentucky Power's native load, reflect fuel expenses, and as such, are properly included in the Company's base fuel costs. Monthly variations in these amounts are properly recovered (or credited) through Kentucky Power's fuel adjustment clause.

Q. PRIOR TO JOINING PJM DID KENTUCKY POWER RECOVER SIMILAR CONGESTION SERVICE-RELATED FUEL COSTS THROUGH ITS FUEL ADJUSTMENT CLAUSE?

A. Yes. When operating as a member of the AEP East Pool the Company recovered through its fuel adjustment clause fuel-related costs associated with AEP East Pool's management as a balancing authority of transmission system congestion.

(b) Congestion Hedging Fuel Costs And Credits.

Q. DO THE CONGESTION HEDGING-RELATED COSTS AND CREDITS REPRESENTED BY BILLING LINE ITEMS 1500, 2500, AND 2510 REFLECT FUEL-RELATED EXPENSES AND CREDITS?

A. Yes. These billing lines items represent charges or credits from PJM and are related to the manner in which PJM allocates and auctions auction revenue rights (ARR) and financial transmission rights (FTR). ARR (2510) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period. Net FTR (1500, 2500) serve as credits that offset congestion charges. PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues.

Congestion charges are incurred when generators are re-dispatched to relieve transmission constraints on the PJM system. Because the Commission has found previously that PJM billing line items relating to congestion charges are appropriately recovered through other Kentucky utilities' FACs, it is also appropriate that offsets to those congestion charges also be included in the Company's FAC to help reduce customers' congestion costs in a timely manner.

(c) Ancillary Services-Related Fuel Costs.

Q. PLEASE DESCRIBE THE ANCILLARY SERVICES-RELATED FUEL COSTS REFLECTED IN BILLING LINE ITEM NUMBERS 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1930 AND 2930.

A. The charges and credits associated with these 14 billing line items fall into four fuel-related services sub-groups:

- <u>Regulation and Frequency Response</u> (1340, 2340, 1460) – Regulation and frequency response services require a generator to be on-line and consuming fuel with the ability to increase or decrease its energy output to respond to changes in system load that impact system frequency.

- Energy Imbalance (1350, 2350) – Energy Imbalance services are provided when there is a difference between the Company's scheduled and the actual delivery of energy over a single hour to a load within PJM. These charges and credits are based on real-time LMPs and reflect energy-based costs related to fuel consumption.
- Synchronized Reserve (1360, 2360, 1470) – Synchronized Reserve services require a generator to increase energy output within 10 minutes to correct an imbalance between load and generation. This service requires generators to be on-line and consuming fuel.
- Synchronous Condensing and Reactive Services (1377, 2377, 1480, 1378, 2378, 1490) – Synchronous Condensing Services and Reactive Services are generator-based services that provide the reactive power necessary to maintain system voltage. Operating synchronous condensers or providing reactive power through generating assets requires that the assets be on-line and consuming fuel.

When Kentucky Power was part of the AEP East Pool, the fuel-related costs and credits associated with these services were embedded in the AEP Pool Primary Energy costs that were included in base fuel costs. Monthly variations in those costs were recovered (or credited) through Kentucky Power's fuel adjustment clause.

- Generation Deactivation (1930, 2930) – Generation Deactivation was recently implemented by PJM. It is a generator based service related to two Dominion generation units that PJM requires be available, staying online and consuming fuel to provide voltage support for system reliability. These charges and credits will be recorded in FERC accounts 5550139 and 4470235 respectively.

(d) Miscellaneous Fuel Related Services.

Q. DO THE PJM MISCELLANEOUS BILLING LINE ITEMS (1230, 1250, 1260, 2260, 1370, 1375, 2370, AND 2375) SIMILARLY REFLECT FUEL-RELATED CHARGES AND CREDITS?

A. Yes. As described below, each reflects charges or credits flowing from the consumption of fuel.

- <u>Inadvertent Interchange</u> (1230) – Inadvertent interchange arises when there are differences between the hourly net actual energy flows and net scheduled energy flow onto or out of the PJM control area. As such the charges reflect the consumption of fuel.
- <u>Meter Error Correction</u> (1250) – Meter errors and corrections are reconciled at the end of each month by a meter correction charge or credit. These energy charges by definition reflect fuel costs.
- <u>Emergency Energy</u> (1260, 2260) – Emergency energy is energy bought from other Control Areas or sold to other Control Areas by PJM due to emergencies either within PJM or other Control Areas. Again, these charges and credits reflect fuel costs and credits.
- <u>Operating Reserves</u> (1370, 2370, 1375, 2375) – Operating reserves are the amounts of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of PJM.

(e) Reconciliation billing line items.

Q. WHAT ARE RECONCILIATION BILLING LINE ITEMS 1400, 1410, 1430, 1478 AND WHY ARE THEY PROPERLY CLASSIFIED AS FUEL COSTS?

A. As part of the billing process, PJM reconciles the charges and credits included in its original billing statements. This reconciliation occurs on a two month lag, so that the true-up charge or credit shows up on the PJM bill two months following the original bill. Each of the reconciliation billing line items above in Table 1 directly reflect charges and credits resulting from the reconciliation of fuel-related billing line items.

Because the underlying charges and credits giving rise to the reconciliation billing line items are fuel related charges and credits properly included in base fuel costs currently, it is reasonable for the Company to include these reconciliation amounts in base fuel costs. Similarly, monthly variations in these amounts should be recovered (or credited) through Kentucky Power's fuel adjustment clause.

3. <u>The Commission's Uniform Fuel Adjustment Clause Regulation</u>.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE COMMISSION'S UNIFORM FUEL ADJUSTMENT CLAUSE REGULATION (807 KAR 5:056).

A. The fuel adjustment clause, whereby Kentucky jurisdictional utilities recover and refund on a monthly basis variations in base fuel costs "has been a cornerstone of the electric industry in Kentucky since at least the mid-1930s."[5] Jurisdictional utilities have been required by regulation for almost 40 years (since 1978) to administer their fuel adjustment clauses in conformity with the Commission's "uniform fuel adjustment clause regulation…."[6] The purpose of 807 KAR 5:056 is "to establish a uniform mechanism

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[5] *In the Matter of: The Purchased Gas Cost Adjustment Filing Of Duke Energy Kentucky* at 7, Case No. 2007-00362 (Ky. P.S.C. August 28, 2007).

[6] *Id*.

whereby jurisdictional electric utilities could recover (or refund), on a monthly basis, fuel costs incurred that were in excess of (or less than) the amount of fuel costs included in their base rates."[7] In short, the stated goal of the regulation and the Commission's Orders applying it is the uniform treatment of fuel costs[8] and purchased power costs[9] across all jurisdictional utilities' fuel adjustment clauses.

Q. HOW IS THE COMMISSION'S STATED GOAL OF THE UNIFORM TREATMENT OF FUEL COSTS ACROSS ALL JURISDICTIONAL UTILITIES' FUEL ADJUSTMENT CLAUSES APPLICABLE TO KENTUCKY POWER'S PROPOSAL TO AMEND THE OPERATION OF ITS FUEL ADJUSTMENT CLAUSE?

A. Through no fault of the Commission or the two other PJM-member jurisdictional utilities (Duke Kentucky and East Kentucky Power) it appears that 14 PJM billing line items that are not part of the Company's base fuel costs are part of the base fuel costs of Duke Kentucky and East Kentucky Power. Variations in these costs are not being recovered (or credited) through Kentucky Power's fuel adjustment clause but are reflected in Duke Kentucky and East Kentucky Power's fuel adjustment clauses. As a result, the three PJM members' fuel adjustment clauses are not being administered uniformly.

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[7] *In the Matter of: An Examination Of The Application Of The Fuel Adjustment Clause Of East Kentucky Power Cooperative From November 1, 2013 Through April 30, 2014*, Case No. 2014-00226 at 8 (Ky. P.S.C. January 30, 2015).

[8] *In the Matter of: An Examination Of The Application Of The Fuel Adjustment Clause Of American Electric Power Company From May 1, 2001 Through October 31, 2001*, Case No. 2000-00495-B at 3 (Ky. P.S.C. May 2, 2002).

[9] *See In the Matter of: An Examination Of The Application Of The Fuel Adjustment Clause Of American Electric Power Company From May 1, 2001 Through October 31, 2001*, Case No. 2000-00495-B at 2 (Ky. P.S.C. June 11, 2002).

Q. WHICH BILLING LINE ITEMS CURRENTLY ARE REFLECTED IN THE FUEL ADJUSTMENT CLAUSES OF DUKE KENTUCKY AND EAST KENTUCKY POWER?

A. The 14 billing line items reflected in the fuel adjustment clauses of East Kentucky Power or Duke Kentucky, or both, but not reflected in Kentucky Power's fuel adjustment clause include 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370,1375, 2375 and are indicated in Table 1 above. These billing line items are among the 37 fuel-related costs and credits the Company is proposing to include in its base fuel costs.

Q. WOULD THE COMPANY'S PROPOSAL TO INCLUDE THE 14 BILLING LINE ITEMS CURRENTLY REFLECTED IN THE FUEL ADJUSTMENT CLAUSES OF DUKE KENTUCKY AND EAST KENTUCKY POWER AND SHOWN IN TABLE 1, ADVANCE THE COMMISSION'S STATED GOAL OF THE UNIFORM TREATMENT OF FUEL COSTS ACROSS ALL KENTUCKY JURISDICTIONAL UTILITIES FUEL ADJUSTMENT CLAUSES?

A. Yes.

C. Amendment Of Tariff F.A.C. To Include PJM Billing Line Items

Q. PLEASE DESCRIBE HOW THE COMPANY IS PROPOSING TO AMEND TARIFF F.A.C. IN ORDER TO RECOGNIZE THE INCLUSION OF THE PJM BILLING LINE ITEMS.

A. The Company is proposing to amend Tariff F.A.C. to recognize the following billing line items as fuel costs: 1200, 1205, 1220, 1225, 1420, 2220, 2420, 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2500, 2510, 1930 and 2930. The variation in these fuel costs and credits from the corresponding amounts included in base fuel is properly recoverable (or will be credited) through the FAC. A copy of the proposed amended tariff is in Exhibits D and E of Section II of the Application.

Q. HAS THE COMPANY CONDUCTED AN ANALYSIS TO DETERMINE THE EFFECT ON THE FAC OF BILLING LINE ITEM RECOVERING VARIATIONS IN THE 37 BILLING LINE ITEMS ON THE OPERATION OF THE COMPANY'S FAC?

A. Yes. Table 2 below illustrates the effect on the operation of the Company's as filed fuel rate if the 37 billing line items had been reflected in base fuel expense during the test year.

Table 2

Fuel Rate Comparison			
Month & Year	**As Filed Monthly Fuel Rate in Cents per kWh**	**BLI Supplemented As Filed Monthly Fuel Rate in Cents per kWh**	**BLI Supplemented Monthly Fuel Rate Above or (Below) As Filed Fuel Rate Cents per kWh (C3) - (C2)**
March 2016	2.707	2.747	0.040
April 2016	2.519	2.498	(0.021)
May 2016	2.406	2.402	(0.004)
June 2016	2.823	2.845	0.022
July 2016	2.980	3.009	0.029
August 2016	3.076	3.063	(0.013)
September 2016	3.095	3.107	0.012
October 2016	3.070	3.105	0.035
November 2016	2.961	2.978	0.017

December 2016	2.828	2.843	0.015
January 2017	2.818	2.802	(0.016)
February 2017	2.769	2.738	(0.031)
Test Year Avg			**0.007**

Q. ARE THERE LARGE DIFFERENCES BETWEEN THE AS FILED FAC RATES AND THE FAC RATES INCLUDING THE BILLING LINE ITEMS?

A. No. The differences between the proposed FAC fuel rates including the billing line items and the as filed fuel rates are minimal. As can be seen from Table 2 column 4, the 12 month average difference between the as filed fuel rate and the fuel rate including the billing line items is 0.007 cents per kWh. The differences range from a high of 0.040 cents per kWh in March 2016 to a low of (0.031) cents per kWh in February 2017. For five of the 12 months in the test year, the differences are negative, meaning that the fuel rate inclusive of billing line items is less than the as filed rate. Of the remaining 7 months, three are less than 0.02 cents per kWh and only two are greater than 0.03 cents per kWh.

Q. WHAT WOULD HAVE BEEN THE EFFECT ON A TYPICAL RESIDENTIAL CUSTOMER'S BILL IF THE BILLING LINE ITEMS HAD BEEN INCLUDED IN FAC RATES?

A. All else being equal over the 12 month period, assuming an average usage level of 1,247 kWh and the 12 month average rate difference (0.007 cents per kWh), an average residential customer's monthly bill would have been $0.09 higher (1,247 kWh x $0.00007).

Q. WHAT IS THE COMPANY'S CONCLUSION REGARDING THE DIFFERENCES IN AS FILED FUEL RATES AND FUEL RATES INCLUDING THE BILLING LINE ITEMS?

A. Moving the collection of the billing line items out of the base rate and into the base fuel rate and recovering monthly differences through the FAC ensures that the Company collects no more and no less than its actual fuel cost.

Q. PLEASE SUMMARIZE WHY IT IS REASONABLE TO AMEND TARIFF F.A.C. TO RECOVER THE [37] PJM BILLING LINE ITEMS LISTED ABOVE IN TABLE 1 THROUGH THE COMPANY'S FAC.

A. First, each of the PJM billing line item charges or credits in Table1 are related to fuel consumption. Second, the Commission recognized previously that 14 of the billing line items listed in in Table 1 above are appropriate for recovery through the FAC. Granting the Company's request for similar treatment to recover these billing line items through its FAC promotes the policy underlying 807 KAR 5:056 which contemplates the uniform treatment of fuel costs across all Kentucky jurisdictional utilities. Third, and most importantly, recovering variable fuel-related PJM billing line items through the FAC ensures that customers pay no more than and no less than their actual cost of service in a more timely fashion.

Q. HAS THE COMPANY PROVIDED AN UPDATED FUEL ADJUSTMENT CLAUSE FORM TO SHOW ITS PROPOSAL TO ACCOUNT FOR THE CHARGES AND CREDITS ASSOCIATED WITH THE 37 BILLING LINE ITEMS?

A. Yes. On the FAC forms, the net value of the 37 additional billing line items will be combined with net transmission line loss billing line items. Accordingly, FAC Page 2 of 5, Line H. has been amended to read "Net Fuel Related PJM Billing Line Items for Month." FAC Page 5 of 5 Line E. has been amended to read "Net Fuel Related PJM Billing Line Items for Month." Lines H and E respectively formerly accounted for net transmission line losses. The updated forms are provided in Exhibit JAR-4.

D. <u>Gains And Losses From Incidental Gas Sales</u>.

Q. BRIEFLY DESCRIBE HOW KENTUCKY POWER PROCURES NATURAL GAS TO BIG SANDY UNIT 1.

A. The Company nominates Big Sandy Unit 1 in the PJM day ahead electric power market based in part on the price of natural gas purchased for delivery the next day.

Q. DESCRIBE WHAT HAPPENS IF PJM DOES NOT SELECT BIG SANDY UNIT 1 TO RUN THE NEXT DAY.

A. If the PJM electric power market clearing price is less than Big Sandy Unit 1's Day Ahead nomination price, then on an economic basis it will not be selected to run in the Real Time Market. When that happens, the natural gas purchased for Big Sandy must either be stored on the Columbia Gas pipeline or be sold. If there is not sufficient pipeline capacity, Columbia Gas will inform the Company that it must sell the gas.

Q. HAVE THERE BEEN INSTANCES WHERE THE COMPANY WAS REQUIRED TO SELL NATURAL GAS?

A. Yes. In August, September and November of 2016, there were days when Big Sandy Unit 1 was not selected by PJM to run and the Company was required to sell natural gas that had been purchased for delivery on that day in order to avoid pipeline penalties. In those three months the Company had a net gain from incidental gas sales totaling $13,981.97.

Q. DID THE COMPANY FLOW THE GAIN OR LOSS FROM THE SALE THROUGH THE FUEL ADJUSTMENT CLAUSE?

A. No. Only the cost of natural gas that has been burned can be passed through the FAC.

Q. WHAT IS THE COMPANY'S RECOMMENDATION REGARDING THE INCIDENTAL GAIN OR LOSS FROM THE SALE OF NATURAL GAS?

A. The company is proposing to recover the gains and losses from incidental sales of natural gas through the Purchase Power Adjustment ("Tariff PPA"). Any gains and losses from these incidental sales will be included with other purchase power related costs as part of the calculation of the annual purchase power adjustment factor. Additional detail regarding the Company's proposed changes to Tariff PPA is included in the testimony of Company Witness Vaughan.

Q. IS IT REASONABLE TO PASS THE PROCEEDS FROM THE INCIDENTAL SALE OF NATURAL GAS THROUGH TARIFF PPA?

A. Yes. It is reasonable to pass incidental gas sale proceeds through Tariff PPA for several reasons. First, the price of natural gas can fluctuate widely depending on the season and weather. Traditionally, the price of gas is lower in the summer months and increases during the winter months and can spike during short term weather or unexpected events that could disrupt supply. Second, the Company only purchases gas for Big Sandy Unit 1 when it expects that PJM will select the unit to run the next day. The number of days that the unit is not selected to run and Company is required to sell gas means that the gains or losses from the incidental gas sales is unpredictable. Therefore, passing the gas sale proceeds through the PPA ensures that customers receive the net benefits from the sales over time.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Kentucky Power Company
Analysis of
Over/(Under) Recovery of Fuel
Test Year Ended February 28, 2017

Ln No (1)	Month (2)	Year (3)	Month kWh Sales (4)	Billed Olive Hill Vanceburg Sales (kWh) (5)	Juris. KWH Sales (C4-C5) (6)	Total Company Fuel Cost* (7)	Juris. Fuel Cost (C6*(C7/C4) (8)	Deferred Fuel (9)	Juris. Total Fuel Cost (C8+C9) (10)	Dollars Per kWh (C7/C4) (11)	Billed and Accrued KWH (12)	Base Fuel (13)	FAC (C11-C13) (14)	Base Fuel Revenue (C12*C13) (15)	F.A.C. Revenue (C12*C14) (16)	Total Fuel Revenue (C15+C16) (17)	Over(Under) Recovery of Fuel (C17-C10) (18)
	November	2015	481,798,000	6,700,799	475,097,201	$11,655,221	$11,493,121	($1,053,717)	$10,439,404	0.02419	468,553,238	0.02725	(0.00306)				
	December	2015	511,879,000	7,432,620	504,446,380	$13,315,184	$13,121,844	($287,309)	$12,834,535	0.02601	479,312,524	0.02725	(0.00124)				
1	January	2016	665,788,000	9,473,815	656,314,185	$17,202,769	$16,957,982	($626,080)	$16,331,902	0.02584	650,232,642	0.02725	(0.00141)	$17,718,839	($1,989,712)	$15,729,127	($602,775)
2	February	2016	564,781,000	8,014,903	556,766,097	$14,448,360	$14,243,321	$1,313,441	$15,556,762	0.02558	534,846,513	0.02725	(0.00167)	$14,574,567	($663,210)	$13,911,357	($1,645,405)
3	March	2016	483,533,000	6,687,102	476,845,898	$13,089,234	$12,908,214	$562,737	$13,470,951	0.02707	464,732,880	0.02725	(0.00018)	$12,663,971	($655,273)	$12,008,698	($1,462,253)
4	April	2016	438,583,000	5,914,616	432,668,384	$11,047,815	$10,898,827	($672,629)	$10,226,198	0.02519	448,756,582	0.02725	(0.00206)	$12,228,617	($749,423)	$11,479,194	$1,252,996
5	May	2016	441,473,000	5,950,123	435,522,877	$10,622,574	$10,479,404	$851,403	$11,330,807	0.02406	440,975,498	0.02725	(0.00319)	$12,016,582	($79,376)	$11,937,206	$606,399
6	June	2016	473,438,000	6,725,770	466,712,230	$13,366,848	$13,176,955	($1,965,491)	$11,211,464	0.02823	440,338,429	0.02725	0.00098	$11,999,222	($907,097)	$11,092,125	($119,339)
7	July	2016	508,874,000	7,650,946	501,223,054	$15,164,338	$14,936,341	($2,686,682)	$12,249,659	0.02980	488,427,142	0.02725	0.00255	$13,309,640	($1,558,083)	$11,751,557	($498,102)
8	August	2016	540,609,000	7,994,472	532,614,528	$16,631,325	$16,385,383	($608,771)	$15,776,612	0.03076	529,582,781	0.02725	0.00351	$14,431,131	$518,991	$14,950,122	($826,490)
9	September	2016	456,943,000	6,481,497	450,461,503	$14,140,732	$13,940,153	($316,329)	$13,623,824	0.03095	427,433,933	0.02725	0.00370	$11,647,575	$1,089,957	$12,737,532	($886,292)
10	October	2016	415,353,000	5,491,982	409,861,018	$12,751,558	$12,582,951	$519,533	$13,102,484	0.03070	431,422,751	0.02725	0.00345	$11,756,270	$1,514,294	$13,270,564	$168,080
11	November	2016	465,829,000	6,382,412	459,446,588	$13,793,354	$13,604,369	$903,225	$14,507,594	0.02961	465,575,442	0.02725	0.00236	$12,686,931	$1,722,629	$14,409,560	($98,034)
12	December	2016	571,200,000	8,098,782	563,101,218	$16,154,152	$15,925,110	$386,333	$16,311,443	0.02828	540,372,222	0.02725	0.00103	$14,725,143	$1,864,284	$16,589,427	$277,984
13	January	2017	548,930,000	7,869,911	541,060,089	$15,471,284	$15,249,475	$403,017	$15,652,492	0.02818	517,639,342	0.02725	0.00093	$14,105,672	$1,221,629	$15,327,301	($325,191)
14	February	2017	461,262,000	6,435,030	454,826,970	$12,771,984	$12,593,803	$411,712	$13,005,515	0.02769	443,890,642	0.02725	0.00044	$12,096,020	$457,207	$12,553,227	($452,288)
15	Mar - Feb Total		**5,806,027,000**	**81,682,643**	**5,724,344,357**	**$165,005,198**	**$162,680,985**	**($2,211,942)**	**$160,469,043**		**5,639,147,644**			**$153,666,774**	**$4,439,739**	**$158,106,513**	**($2,362,530)**

* Includes purchased power costs allocated to internal load

Source:

Column 4	Page 3 of 5 Monthly FAC Filing Total Sales
Column 5	Total monthly bills for Olive Hill and Vanceburg (FAC P. 4 of 5 Ex. June FAC Recorded in April On Chart)
Column 6	Page 4 of 5 FAC Filing KY Jurisdictional Sales
Column 7	Page 2 of 5 Monthly FAC Filing Total Fuel Costs (Line I.)
Column 9	Deferred Fuel Report
Column 12	Monthly Tariff Summaries MACCS Report MSCR0194 Final B&A page 9-1B
Column 13	Page 1 of 5 Monthly FAC Filing Base Fuel Costs
Column 14	Page 1 of 5 Monthly FAC Filing Monthly Adjustment Two Months Prior

Kentucky Power Company
Analysis of
Over/(Under) Purchase Power Adjustment
Test Year Ended February 28, 2017

Ln No	Month	Year	Cost of Fuel Related Substitute Generation for F.O.	Cost of Fuel Which Would Have Been Used In Plants During a F.O.	Tariff CS-IRP Cost of Credits	Monthly Net PPA Net Costs* (C4) - (C5) + (C6)	Current Month Olive Hill/Vanceburg Revenues	Current Month Retail Revenues	Total Company Revenues (C8) + (C9)	Current Month Retail Revenue Percentage (C9) / (C10)	Current Month Retail Allocation Of Net Cost (C7 * C11)	PPA Net Costs Previous 2 Months Prior	PPA Revenues Received In Current Month	Previous Month Net (Over)/Under Recovery (C13) - (C14)	Total Monthly Net (Revenue) Costs Allocated to Retail (C12) + (C15)	Net Over / (Under) (C14) +(C15) - (C16)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
1	January	2016	355,061	285,836	0	69,225	785,542	52,352,710	53,138,252	0.985217		12,073	15,146	(3,073)	(3,074)	(15,147)
2	February	2016	0	0	0	0	729,065	57,216,132	57,945,196	0.987418	68,354	220,746	269,504	(48,758)	19,596	(201,150)
3	March	2016	0	0	0	0	535,792	49,078,552	49,614,345	0.989201	0	191,810	191,935	(124)	(124)	(191,935)
4	April	2016	157,639	157,639	0	0	548,164	36,409,198	36,957,362	0.985168	0	(48,758)	14,584	(63,342)	(63,342)	(14,584)
5	May	2016	454,578	448,092	0	6,486	573,287	38,961,878	39,535,165	0.985499	0	68,230	1,943	66,287	66,287	(1,943)
6	June	2016	0	0	0	0	560,405	44,829,564	45,389,969	0.987654	6,406	(63,342)	4,888	(68,230)	(61,823)	1,520
7	July	2016	0	0	0	0	624,301	47,231,370	47,855,671	0.986955	0	66,287	(1,377)	67,663	67,663	1,377
8	August	2016	461,454	351,711	8,685	118,428	687,122	53,464,855	54,151,977	0.987311	8,575	(68,230)	7,091	(75,321)	(66,748)	1,482
9	September	2016	991,796	960,021	25,009	56,784	566,655	48,039,619	48,606,274	0.988342	133,182	74,070	(278)	74,349	207,531	133,460
10	October	2016	0	0	16,317	16,317	474,923	41,830,446	42,305,369	0.988774	47,552	(75,321)	6,381	(81,703)	(34,150)	41,171
11	November	2016	0	0	16,163	16,163	566,837	41,509,482	42,076,319	0.986528	15,945	82,923	109,785	(26,862)	(10,917)	(93,840)
12	December	2016	944,941	787,199	5,885	163,627	706,405	53,855,937	54,562,342	0.987053	5,809	51,479	61,688	(10,209)	(4,400)	(55,879)
13	January	2017	2,900,034	2,460,421	728	440,341	653,520	56,744,599	57,398,119	0.988614	156,666	20,690	54,968	(34,278)	122,388	101,698
14	February	2017			11,776	11,776	548,639	50,751,756	51,300,395	0.989305	446,561	5,737	(3,454)	9,191	455,752	450,015
									Test year ending February 28th		**820,696**	**305,574**	**448,154**	**(142,580)**	**678,117**	**372,542**

* Excludes any costs recovered through the FAC

Source: Columns 4 - 5 Power Transaction Schedule
Column 14 Revenu Report MCSR164N

PJM Billing Line Item Uniform Recovery Meeting

January 29, 2016

AGENDA

I. **Introduction – John Rogness**

   a. **Pre RTO**

   b. **Post RTO**

II. **BLIs Appropriately Recovered Through FAC By A Utility – John Rogness**

See BLIs – Uniform Recovery and BLIs – Non-Uniform Recovery Spreadsheet Handouts

III. **Additional BLIs Reasonably Recovered Through FAC**

   a. Reconciliation BLIs - Julie Tucker

   1400, 1410, 1430, and 1478

   b. Ancillary Services - Alex Vaughan and John Swez

   1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, and 1490,

   c. Congestion Hedging Related BLIs - Alex Vaughan and John Swez

   1500, 2500, and 2510

See Additional BLIs – Eligible Spreadsheet Handout and Ancillary Services Handout.

IV. **Questions**

PJM BILLING LINE ITEMS CURRENTLY RECOVERED UNIFORMLY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	Included In FAC By KY Power Co (2014-00450)	Included In FAC By East KY Power Coop (2014-00451)	Included in FAC By Duke KY (2014-00454)	PSC Allow Recovery through FAC?
1	1200	Day-ahead Spot Market Energy	Day-ahead energy market net hourly PJM Interchange MWh are calculated for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Day-ahead Charges: Net day-ahead PJM Interchange is charged hourly at the PJM-wide day-ahead system energy price. Charges are positive for net buyers and negative for net sellers of day-ahead spot market energy.	Yes	Yes[1]	Yes[3]	Approved
2	1205	Balancing Spot Market Energy	Real-time energy market net hourly PJM Interchange MWh are calculated for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. Balancing Charges: Net real-time deviations from day-ahead PJM Interchange is charged hourly at the PJM-wide real-time system energy price. Charges may be positive or negative depending on the direction of the real-time deviation from day-ahead interchange.	Yes	Yes[1]	Yes[3]	Approved
3	1220	Day-ahead Transmission Losses	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). An hourly day-ahead Net Loss Bill is calculated as day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead loss prices) minus day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead loss prices). Hourly day-ahead implicit loss charges equal the day-ahead Net Loss Bill. Hourly explicit loss charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable).	Yes[4]	Yes[2]	Yes[3]	Approved
4	1225	Balancing Transmission Losses	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). An hourly balancing Net Loss Bill is calculated as balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time loss prices) minus balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time loss prices). Hourly balancing implicit loss charges equal the balancing Net Loss Bill. Hourly explicit loss charges for balancing energy transactions equal any real-time deviations from day-ahead transaction MWh times the difference between real-time sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable).	Yes[4]	Yes[2]	Yes[3]	Approved

Please note that any Charge that is recovered / passed through the FAC necessitates that the corresponding Credit and Reconciliation be recovered / passed through the FAC.

1. EKPC uses the PJM MSRS hourly data reports (Charge Codes 1200 and 1205) to determine the purchase and sales mw and includes the portion applicable to purchases in the FAC.
2. EKPC takes the amount from the invoice for charge codes 1210, 1215, 1220, 1225 and allocates it between purchases & sales and includes the balancing on generation portion in the FAC.
3. DEK uses the PJM hourly data to determine the hourly purchases and hourly sales MWhrs and multiplies it by the hourly LMP which includes the energy price, marginal loss price, and transmission marginal congestion price. Therefore, none of the BLIs are taken directly from the invoice.
4. Approved in Case 2007-00522. The PSC found that the recovery of the charges and credits related to marginal line losses are the same types of costs that were previously included in KPCo's FAC calculations.

PJM BILLING LINE ITEMS CURRENTLY RECOVERED NON-UNIFORMLY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	Included In FAC By KY Power Co (2014-00450)	Included In FAC By East KY Power Coop (2014-00451)	Included in FAC By Duke KY (2014-00454)	PSC Allow Recovery through FAC?
1	1210	Day-ahead Transmission Congestion	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders.	No	Yes[1]	Yes[2]	Approved
2	2210	Transmission Congestion Credit	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders.	No	Yes	No	Approved
3	1215	Balancing Transmission Congestion	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders.	No	Yes[1]	Yes[2]	Approved
4	1218	Planning Period Congestion Uplift	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements.	No	Yes	No	Approved
5	2217	Planning Period Excess Congestion Credit	Total congestion revenues allocated as hourly credits based on FTR target allocations. Excess hourly congestion credits are used to proportionately eliminate target deficiencies in other hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period with any excess at the end of the planning period allocated proportionately to FTR holders with net positive FTR target allocations for that planning period. Any deficiencies remaining at the end of a planning period are eliminated by reallocating all planning period FTR congestion revenues among FTR holders to yeild a uniform ratio of deficiency.	No	Yes	No	Approved
6	2218	Planning Period Congestion Uplift Credit	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements.	No	Yes	No	Approved
7	1230	Inadvertent Interchange	Charges: PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares.	No	Yes	No	Approved
8	1250	Meter Error Correction	Charges: Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	No	Yes	No	Approved
9	1260	Emergency Energy	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas.	No	Yes	No	Approved

10	2260	Emergency Energy Credit	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. Credits: Hourly net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	No	Yes	No	Approved
11	1420	Load Reconciliation for Transmission Losses	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag.	Yes	Yes	No	Approved
12	2220	Transmission Losses Credit	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving 31% of their allocation).	Yes	Yes	No	Approved
13	2420	Load Reconciliation for Transmission Losses	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving 31% of their allocation) on a two-month billing lag.	Yes	Yes	No	Approved
14	1370	Day-ahead Operating Reserve Charge	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Total daily cost of operating reserve in the day-ahead market excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares.	No	Yes	No	Approved
15	2370	Day-ahead Operating Reserve Credit	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Daily credits provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP.	No	Yes	Yes	Approved
16	1375	Balancing Operating Reserve	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWh); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports.	No	Yes	No	Approved
17	2375	Balancing Operating Reserve Credit	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Daily credits for specified operating period segments provided to eligible pool-scheduled generators, demand response, and import transactions in real-time for any portion of their offer amount in excess of: (1) scheduled MWh times day-ahead bus LMP; (2) MWh deviation from day-ahead schedule times real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any day-ahead scheduling reserve market revenues in excess of offer plus opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs and (7) any applicable reactive services credits. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also provided to generators reduced or suspended by PJM for reliability purposes.	No	Yes	Yes	Approved

Please note that any Charge that is recovered / passed through the FAC necessitates that the corresponding Credit and Reconciliation be recovered / passed through the FAC.

1. EKPC takes the amount from the invoice for charge codes 1210, 1215, 1220, 1225 and allocates it between purchases & sales and includes the balancing on generation portion in the FAC.

2. DEK uses the PJM hourly data to determine the hourly purchases and hourly sales MWhrs and multiplies it by the hourly LMP which includes the energy price, marginal loss price, and transmission marginal congestion price.
Therefore, none of the BLIs are taken directly from the invoice.

ADDITIONAL ELIGIBLE PJM BILLING LINE ITEMS NOT CURRENTLY RECOVERED THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
	RECONCILIATION BLIs FOR ITEMS CURRENTLY RECOVERED THROUGH THE FAC			
1	1400	Load Reconciliation for Spot Market Energy	Retail load schedules with reconciliation data (in kWh) provided by the applicable electric distribution company (EDC) are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the Balancing Spot Market Energy charge (1205). The Balancing Spot Market Energy charge trues up the Day ahead Sport Market Energy charge (1200). Both 1200 and 1205 are recovered through the FAC currently.
2	1410	Load Reconciliation for Transmission Congestion	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the Balancing Transmission Congestion charge (1215) recovered through FAC currently. Balancing Transmission Congestion (1215) trues up Day Ahead Transmission Congestion (1210).
3	1430	Load Reconciliation for Inadvertent Interchange	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the inadvertent Interchange charge (1230) recovered through FAC currently.
4	1478	Load Reconciliation for Balancing Operating Reserve	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an daily basis using a $/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the Balancing Operating Reserve (1375) recovered through FAC currently.
	ANCILIARY SERVICE BLIs*			
5	1340	Regulation and Frequency Response Service Charge	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. Charges: PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). PJM LSEs also have an hourly regulation mileage obligation equal to their adjusted obligation ratio share of the mileage component of the regulation supplied. Hourly charges calculated as adjusted obligations times the regulation market capability and performance clearing prices and the regulation mileage obligation times the regulation market performance clearing price. Additional charges are assessed for any unrecovered cost payments that PJM provides to regulation suppliers and allocated to regulation market purchasers based on their share of any portion of their adjusted obligation in excess of their self-scheduled regulation.	Regulation refers to a specific resource (generator) with appropriate telecommunications, control and response capability to increase or decrease its energy output in response to a regulating control signal to control for frequency deviations. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide regulating and frequency response services unless it is online and consuming fuel.

6	2340	Regulation and Frequency Response Service Credit	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. Credits: Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance) priced at the regulation market capability clearing price. Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance and the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio)) priced at the regulation market performance clearing prices. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost.	This is the same type of credit that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide regulating reserves unless it is online and consuming fuel.
7	1460	Load Reconciliation for Regulation and Frequency Response Service	Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable electric distribution company (EDC) are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	The reconciliation process is a required component of PJM participation. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide regulating and frequency response services unless it is online and consuming fuel. Corresponds to 1340.
8	1350	Energy Imbalance Service Charge	Each Transmission Customer must purchase Energy Imbalance service through PJM. For each Network Customer and Point-to-Point Transmission Customers. Energy Imbalance service is considered PJM Interchange and is therefore accounted for as Spot Market energy using hourly Locational Marginal Prices (LMP).	Billing based on real-time LMP which is an energy based cost type that consumes fuel.
9	2350	Energy Imbalance Service Credit	Energy Imbalance service is provided when a difference occurs between the scheduled and the actual delivery of energy over a single hour to a load that is located within PJM. PJM must offer this service when Transmission Service is used to serve load located with PJM. Currently PJM has none of these types of transmission customers.	Billing based on real-time LMP which is an energy based cost type that consumes fuel.
10	1360	Synchronized Reserve Charge	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total assignments (adjusted for any bilateral synchronized reserve transactions). Tier 1 charges for each participant equal their ratio share of the total Tier 1 credits based on the amount of Tier 1 synchronized reserve applied to their obligation. Tier 2 hourly charges for each participant equal their reserve market's hourly Tier 2 clearing price times the MWh of Tier 2 synchronized reserve self-scheduled that hour toward their obligation plus that which was purchased from that synchronized reserve market, plus their share of any unrecovered costs incurred by assigned Tier 2 resources above the Tier 2 clearing price, plus their share of costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour.	Synchronized reserve is the reserve capability required to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or reducing demand. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide synchronized reserves unless it is online and consuming fuel.
11	2360	Synchronized Reserve Credit	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. Generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event when non-synchronized reserve clearing prices are zero receive Tier 1 credits equal to response MWh times synchronized reserve energy premium less its hourly LMP. During hours when the non-synchronized reserve clearing price is non-zero resources receive Tier 1 credits equal to the lesser of the response MWh or the Tier 1 estimate times the applicable reserve zone's Synchronized Reserve Market Clearing Price. Resources receive Tier 2 hourly credits for pool and self-scheduled synchronized reserve priced at the applicable reserve zone's Tier 2 clearing price. Additional credits provided to pool-scheduled synchronized reserve resources for any portion of synchronized reserve offer plus opportunity cost, energy use cost, and start-up cost not recovered via Synchronized Reserve Market Clearing Price revenues.	This is the same type of credit that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide synchronized reserves unless it is online and consuming fuel.

12	1470	Load Reconciliation for Synchronized Reserve	Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	Corresponds to 1360. The reconciliation process is a required component of PJM participation. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide synchronized reserves unless it is online and consuming fuel.
13	1377	Synchronous Condensing Charge	Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares.	This service / function was self supplied prior to participation in PJM. This payment is appropriate to recover through the FAC because energy (fuel) is required to operate a synchronous condenser. A synchronous condenser is a machine that operates without mechanical load whose purpose is to supply or absorb reactive power on the transmission system for voltage control purposes.
14	2377	Synchronous Condensing Credit	Daily credits for condensing and energy use costs are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services.	Corresponds to 1377. This is the same type of credit that was included in a utility's FAC filings prior to joining an RTO. Energy (fuel) is required to operate a synchronous condenser. A synchronous condenser is a machine that operates without mechanical load whose purpose is to supply or absorb reactive power on the transmission system for voltage control purposes.
15	1480	Load Reconciliation for Synchronous Condensing	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	Corresponds to 1377. On a two month lag, this is a true up for actual synchronous condenser performance.
16	1378	Reactive Services Charge	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Charges: Total daily cost of reactive services and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control is allocated separately for each PJM transmission zone based on real time load (without losses) ratio shares in the applicable transmission zone.	Reactive power is the product of voltage and the out-of-phase component of alternating current. It's measured in VARs and is produced by capacitors and overexcited generators and absorbed by reactors and other inductive devices. Energy (fuel) is required to run these machines.
17	2378	Reactive Services Credit	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Credits: Daily credits are calculated for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services.	Reactive power is the product of voltage and the out-of-phase component of alternating current. It's measured in VARs and is produced by capacitors and overexcited generators and absorbed by reactors and other inductive devices. Energy (fuel) is required to run these machines.
18	1490	Load Reconciliation for Reactive Services	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's $/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	Corresponds to 1378. The reconciliation process is a required component of PJM participation.
	CONGESTION HEDGING RELATED BLIs			
19	1500	Financial Transmission Rights Auction	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price.	Related to congestion charges. Generators are redispatched out of economic order to relieve congestion. This results in additional fuel cost.

20	2500	Financial Transmission Rights Auction	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	Related to congestion charges. Generators are redispatched out of economic order to relieve congestion. This results in additional fuel cost.			
21	2510	Auction Revenue Rights	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. Credits: Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	Related to congestion charges. Generators are redispatched out of economic order to relieve congestion. This results in additional fuel cost.			
		* See Anciliary Services Handout					
		Please note that any Charge that is recovered / passed through the FAC necessitates that the corresponding Credit and Reconciliation be recovered / passed through the FAC.					

PJM Energy and Ancillary Service BLIs – FAC Inclusion Rationale

PJM optimizes the operation of the electric power system within its geographic footprint by committing and dispatching generators in order of production cost, from lowest to highest, until generation output is equal to load, plus any operating and synchronized reserves for that hour's operations. Also included in PJM's optimization solution are the costs of dispatching resources in a way that recognizes system transmission constraints and physical transmission line losses. Prior to RTO participation, these services and the recognition of operating constraints were included in the utilities' daily operations and were not delineated into separate products. Thus, the fuel costs associated with these services were included in the utilities' average fuel costs and were included in their respective Kentucky fuel adjustment clauses (FAC).

The costs of regulation service, such as when a generator is required to operate at a point less than full capability, are also included in PJM's optimization solution. Average $/MWh fuel cost will be higher at a loading less than full capability. Before the advent of RTO markets, this cost was also embedded within the utilities' total system fuel cost and was not uniquely quantified.

Least cost utility operation, whether in a vertically integrated utility (pre-PJM) or in an RTO market, requires co-optimization of both energy and ancillary services to select a mix of generators that provides the overall least-cost solution[1]. PJM co-optimizes the energy and ancillary services markets in order to minimize cost throughout its footprint. The combined markets are designed to cover combined generator costs[2].

PJM's market based ancillary service markets for regulation service, synchronized reserves, operating reserves, and the costs of dispatching the system in a manner that recognizes transmission constraints are the same types of costs that were included the utilities' FAC calculations prior to joining PJM. Therefore, the associated PJM billing line items should be uniformly recoverable through the FAC for all of the KY utilities. Additionally, the utilities believe that not only should the charges[3] for regulation service, synchronized reserves, operating reserves, transmission congestion, and transmission losses be eligible for FAC

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[1] National Renewable Energy Laboratory. (2013). Fundamental Drivers of the Cost and Price of Operating Reserves. Technical Report.

[2] PJM (2009). A Review of Generation Compensation and Cost Elements in the PJM Markets.

[3] In addition to monthly billed charges by PJM, any adjustments or load reconciliations made by PJM to these charges should be FAC includable.

recovery, but so should any credits and reconciliations paid to the utilities for providing said services to PJM, or otherwise allocated to the utilities by PJM as a natural offset to the PJM charges.

The utilities recognize that some of the PJM charges and credits in question, for some of the utilities, are to some degree included in their respective base rates and would not request to include those items in FAC calculations until they are removed from base rates through a general rate case.

ADDITIONAL PJM BILLING LINE ITEMS NOT ELIGIBLE FOR RECOVERY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
1	1240	Day-Ahead Economic Load Response Charge	For day-ahead and real-time economic load response, the Curtailment Service Provider's (CSP's) Load Serving Entity (LSE) is charged the difference between LMP and the retail rate, as applicable, times the MWh reduction.	Load response; not includable in FAC
2	2240	Day Ahead Economic Load Response Credit	Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWh times LMP (minus retail rate, as applicable).	Load response; not includable in FAC
3	1241	Real Time Economic Load Response Charge	For day-ahead and real-time economic load response, the CSP's LSE is charged the difference between LMP and the retail rate, as applicable, times the MWh reduction.	Load response; not includable in FAC
4	2241	Real-Time Economic Load Response Credit	Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWh times LMP (minus retail rate, as applicable).	Load response; not includable in FAC
5	1242	Day-Ahead Load Response Charge Allocation Charge	This is a socialized piece of the load response, like emergency energy purchases	Load response; not includable in FAC
6	1243	Real Time Load Response Charge Allocation Charge	This is a socialized piece of the load response, like emergency energy purchases	Load response; not includable in FAC
7	1245	Pre-Emergency and Emergency Load Response Charge	For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	Load response; not includable in FAC : Denied in EKPC Case
8	2245	Emergency Load Response Credit	Emergency load response credits are provided to Curtailment Service Providers (CSPs) equal to the reduced MWh times LMP (minus retail rate, as applicable).	Load response; not includable in FAC : Denied in EKPC Case
9	1371	Day-Ahead Operating Reserve for Load Response	The daily total cost of Day-ahead Operating Reserve which includes Day-ahead Load Response Operating Reserve payments are allocated and charged to PJM Members in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports.	Load response; not includable in FAC
10	2371	Day-Ahead Operating Reserve for Load Response	Total payments to Economic Load Response Participants for cleared day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid.	Load response; not includable in FAC
11	1376	Balancing Operating Reserve for Load Response	The daily total cost of Balancing Load Response Operating Reserve Payments is allocated and charged to PJM Members in proportion to their real-time deviations from day-ahead schedules and generator deviations.	Load response; not includable in FAC
12	2376	Balancing Operating Reserve for Load Response	In cases where the demand reduction follows dispatch as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid, including any submitted shut-down costs.	Load response; not includable in FAC

13	1320	Transmission Owner Scheduling, System Control and Dispatch Service	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. Charges: Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of $0.0912/MWh based on their energy deliveries including losses and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve.	Not fuel related. Charges for operation of Transmission Operator's control centers.
14	2320	Transmission Owner Scheduling, System Control and Dispatch Service	Credits: The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff.	Not fuel related. Revenues for operation of a control center.
15	1450	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal $/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	Not fuel related. Revenues for operation of a control center.
16	1330	Reactive Supply and Voltage Control from Generation and Other Sources Service Charge	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. Charges: Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	Not fuel related. Charges for reactive power.
17	2330	Reactive Supply and Voltage Control from Generation and Other Sources Service Credit	Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements.	Not fuel related. FERC Formula Driven revenue for reactive power.
18	1380	Black Start Services Charge	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. Monthly pool-wide black start revenue requirements and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system.	Not fuel related. Charges for Black Start Capability.
19	2380	Black Start Service Credit	Monthly credits provided to generators with approved black start revenue requirements.	Not fuel related. Revenues for possessing Black Start Capability.
20	1362	Non-Synchronized Reserve Charge	PJM conducts non-synchronized reserve markets to ensure the capability of **generation off-line** and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly nonsynchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total nonsynchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). Hourly charges calculated as adjusted obligations times the Non-Synchronized Reserve Market Clearing Price. Additional charges are assessed for any unrecovered cost payments that PJM provides to non-synchronized reserve suppliers based on adjusted obligation ratio shares.	Not fuel related. This service is provided by an off-line generator that is not consuming fuel. There can, but not always, be an energy market opportunity cost to a generator providing non-synchronized reserve.
21	2362	Non-Synchronized Reserve Credit	PJM conducts non-synchronized reserve markets to ensure the capability of **generation off-line** and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. Hourly credits provided to generation resources supplying non-synchronized reserve at the Non-Synchronized Reserve Clearing Price. Additional credits provided to non-synchronized reserve resources for any portion of nonsynchronized reserve opportunity costs not recovered via Non-Synchronized Reserve Market Clearing Price revenues.	Not fuel related. This service is provided by an off-line generator that is not consuming fuel. There can, but not always, be an energy market opportunity cost to a generator providing non-synchronized reserve.
22	1472	Load Reconciliation for Non-Synchronized Reserve	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	Not fuel related. This service is provided by an off-line generator that is not consuming fuel. There can, but not always, be an energy market opportunity cost to a generator providing non-synchronized reserve.

23	1365	Day-Ahead Scheduling Reserve Charge	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. Charges: PJM LSEs have an hourly day-ahead scheduling reserve obligation equal to their real-time load (without losses) ratio share of the market's total assignments (adjusted for any bilateral day-ahead scheduling reserve transactions). Total hourly cost of day-ahead scheduling reserve is allocated based on obligation ratio shares.	Not fuel related. Generators providing this service may or may not run in the real-time. If the unit does not run then there is no fuel consumed. If a unit provides this service and also runs in the real-time then the cost of fuel consumed will be compensated via the Balancing Spot Market Energy (1205) and other charge types.
24	2365	Day-Ahead Scheduling Reserve Credit	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. Credits: Daily credits provided to eligible generator and demand response resources cleared day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price.	Not fuel related. Generators providing this service may or may not run in the real-time. If the unit does not run then there is no fuel consumed. If a unit provides this service and also runs in the real-time then the cost of fuel consumed will be compensated via the Balancing Spot Market Energy (1205) and other charge types.
25	1475	Load Reconciliation for Day-Ahead Scheduling Reserve	Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	Not fuel related. Generators providing this service may or may not run in the real-time. If the unit does not run then there is no fuel consumed. If a unit provides this service and also runs in the real-time then the cost of fuel consumed will be compensated via the Balancing Spot Market Energy (1205) and other charge types.
	PJM Market Administration Fees:			
26	1301 through 1318	Charges	The charges for PJM scheduling, system control, and dispatch service are allocated on an unbundled basis in accordance with Schedule 9: "PJM Interconnection, L.L.C. Administrative Services" of the PJM Open Access Transmission Tariff. The PJM scheduling, system control and dispatch service charge in any month to any PJM Member is the sum of the charges calculated for that Member under the Service Categories defined in Schedule 9	Not fuel related.
27	1440 through 1448	Reconciliation Charges	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis.	Not fuel related.

KENTUCKY POWER COMPANY

ESTIMATED FUEL COST SCHEDULE

Month Ended: Month

A.	Company Generation		
	Coal Burned	(+)	XXX
	Oil Burned	(+)	XXX
	Gas Burned	(+)	XXX
	Fuel (jointly owned plant)	(+)	XXX
	Fuel (assigned cost during F. O.)	(+)	XXX
	Fuel (substitute for F. O.)	(-)	XXX
	Sub Total		XXX
B.	Purchases		
	Net Energy Cost - Economy Purchases	(+)	XXX
	Identifiable Fuel Cost - Other Purchases	(+)	XXX
	Identifiable Fuel Cost (substitute for F. O.)	(-)	XXX
	Sub Total		XXX
C.	Inter-System Sales Fuel Costs		XXX
	Sub Total		XXX
C1.	Mitchell Plant No-Load Costs		-
D.	Total Fuel Cost (A + B - C)		XXX

E. Adjustment indicating the difference in actual fuel cost for the month of Prior Month and the estimated cost originally reported.

XXX	-	XXX	=	XXX
(actual)		(estimated)		

F.	Total Company Over or (Under) Recovery from Page 4, Line 12		XXX
G.	Grand Total Fuel Cost (D + E - F)		XXX
H.	Net Fuel Related PJM Billing Line Items For Month	Month 2017	XXX
I.	ADJUSTED GRAND TOTAL FUEL COSTS (G + H)		XXX

KENTUCKY POWER COMPANY

FINAL
FUEL COST SCHEDULE

Month Ended: Month

A.	Company Generation		
	Coal Burned	(+)	XXX
	Oil Burned	(+)	XXX
	Gas Burned	(+)	XXX
	Fuel (jointly owned plant)	(+)	XXX
	Fuel (assigned cost during F. O.)		
	Mitchell 1:		
	(XXX KWH X XXX)	(+)	XXX
	Big Sandy 1:		
	(XXX KWH X XXX)	(+)	XXX
	Fuel (substitute for F. O.)	(-)	XXX
	Sub-total		XXX
B.	Purchases		
	Net Energy Cost - Economy Purchases	(+)	XXX
	Identifiable Fuel Cost - Other Purchases	(+)	XXX
	Identifiable Fuel Cost (substitute for F. O.)		
	(XXX KWH X XXX)	(-)	XXX
	Purchase Adjustment for Peaking Unit Equivalent	(-)	XXX (1)
	Sub-total		XXX
C.	Inter-System Sales Fuel Costs		XXX
D.	SUB-TOTAL FUEL COST (A + B - C)		XXX
E.	Net Fuel Related PJM Billing Line Items For Month	Month	XXX
F.	GRAND TOTAL FUEL COSTS (D + E)		XXX

(1) As calculated in accordance with KPSC Order dated October 3, 2002 in Case No. 2000-495-B.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

TYLER H. ROSS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Tyler H Ross being duly sworn, deposes and says he is the Director Regulatory Accounting Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Tyler H Ross

Tyler H Ross

STATE OF OHIO)

) Case No. 2017-00179

COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tyler H Ross, this the 20th day of June 2017.

Notary Public

Notary ID Number: 2014-RE-488323

My Commission Expires: April 29, 2019

DIRECT TESTIMONY OF
TYLER H. ROSS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
TYLER H. ROSS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Tyler H. Ross. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as a Director in Regulatory Accounting Services. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated with a Bachelor of Science Degree in Accounting from The Ohio State University in 1996 and have been a Certified Public Accountant since 2003. I am a member of the Ohio Society of Certified Public Accountants. Starting with my hiring by AEPSC in August 2001, I held staff and leadership positions within AEP's External Financial Reporting Department. I was a Staff Accountant in External Financial Reporting from August 2001 through February 2005. In March 2005, I was promoted to Manager of External Financial Reporting and in August 2008, I was promoted to Director of External Financial Reporting. I led the External Financial Reporting group in both the preparation and filing of quarterly and annual reports in accordance with Generally Accepted Accounting Principles (GAAP) and the reporting requirements of the Securities and Exchange Commission (SEC) and the Federal Energy Regulatory Commission (FERC). In January 2014, I started my present position as Director of Regulatory Accounting Services.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR IN THE REGULATORY ACCOUNTING SERVICES GROUP?

A. My primary responsibilities in Regulatory Accounting Services involve providing the AEP System operating subsidiaries, including Kentucky Power, with accounting support for regulatory filings. This accounting support includes the preparation of cost of service adjustments, accounting schedules, testimony and responses to data requests. I also provide accounting and financial reporting guidance to AEP's accounting organization for regulatory orders received from state commissions.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THIS OR OTHER UTILITY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony before the Public Utilities Commission of Ohio on behalf of Ohio Power Company, an AEP subsidiary and affiliate of Kentucky Power. Additionally, I participated in an informal conference at the Commission on September 1, 2016 to discuss the Company's annual Big Sandy Retirement Rider update and submitted responses to post-informal conference data requests.

III. <u>PURPOSE OF DIRECT TESTIMONY</u>

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

A. The purpose of my direct testimony is to support certain known and measurable adjustments to the Company's revenues and operating expenses for the test year ended (twelve months ended) February 28, 2017. My testimony also supports adjustments to the Company's capitalization and rate base that I have provided to Company Witness Wohnhas related to the Big Sandy Retirement Rider (to be renamed Decommissioning Rider as discussed on pages 6-8).

IV. SUMMARY OF ADJUSTMENTS

Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS THAT YOU HAVE PREPARED FOR THIS CASE.

A. I have prepared two types of adjustments in this case. First, I have prepared numerous adjustments to test year revenue and operating expense amounts. Second, I have prepared adjustments to the Company's capitalization and rate base. The adjustments are described in detail below.

Q. HOW DID YOU DETERMINE THE APPROPRIATE ALLOCATION FACTORS FOR THE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. For all of the adjustments that I sponsor and in my testimony below, I calculated the total company adjustments and applied O&M and retail allocation factors (as applicable) that were provided to me by Company Witness Walsh.

Q. HAVE YOU INCLUDED SUPPORTING WORKPAPERS FOR THE ADJUSTMENTS INCLUDED IN YOUR TESTIMONY?

A. Yes.

V. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. WHAT TYPES OF REVENUE AND OPERATING EXPENSE ADJUSTMENTS DID YOU PREPARE?

A. The adjustments to test year revenue and operating expense that I prepared fall into three broad categories: (1) rider and surcharge-related adjustments, (2) payroll and benefit-related adjustments and (3) depreciation and asset retirement obligation-related adjustments.

Q. CAN YOU PROVIDE A LISTING OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The table below identifies the revenue and operating expense adjustments that I am sponsoring. The details supporting the calculations of these adjustments are included on referenced pages of Exhibit 2 to Section V of the Application.

Description	Reference in Section V, Exhibit 2
Decommissioning Rider	W02
Big Sandy Unit 1 Operation Rider (BS1OR)	W06
Demand Side Management (DSM)	W10
Home Energy Assistance Program (HEAP) Surcharge	W11
Kentucky Economic Development Surcharge	W12
Pension and OPEB Expense	W23
Employee Group Benefits Expense	W24
Severance Expense	W31
Incentive Compensation Expense	W32
Employee Merit Increases	W33
Overtime Related to Employee Merit Increases	W34
Annualization of Payroll Expense	W35

Savings Plan Expense	W36
Medicare Tax Expense	W37
Social Security Tax Expense	W38
Social Security Tax Base	W39
Depreciation Annualization	W42
Big Sandy Unit 1 Depreciation	W43
Asset Retirement Obligation (ARO) Depreciation	W44
Asset Retirement Obligation (ARO) Accretion	W45

Rider and Surcharge Related Adjustments

Q. DID YOU MAKE ANY COST OF SERVICE ADJUSTMENTS FOR RIDERS WITH OVER-/UNDER-RECOVERY ACCOUNTING?

A. Yes. For riders with over-/under-recovery accounting, I made certain adjustments to remove revenue and expense amounts related to the over-/under-recovery in order to avoid including certain rider-related amounts in the determination of the Company's base rates.

Q. PLEASE DESCRIBE THE BASIS FOR OVER-/UNDER-RECOVERY ACCOUNTING.

A. Financial Accounting Standards Board's (FASB's) Accounting Standards Codification (ASC) 980-340-25-1 (regulatory assets) requires deferral accounting based on the existence of a regulatory asset when there is probability of recovery from customers in the future for an under-recovery of costs. ASC 980-405-25-1 (regulatory liabilities) requires deferral accounting based on the existence of a regulatory liability when a true-up to actual costs results in an over-recovery and probability of refund to customers in the future.

Q. FOR WHICH RIDERS DID YOU MAKE TEST YEAR COST OF SERVICE ADJUSTMENTS RELATED TO OVER-/UNDER-RECOVERY?

A. I made adjustments to the test year cost of service for the Decommissioning Rider, the Big Sandy Unit 1 Operation Rider (BS1OR) and the Demand Side Management (DSM) surcharge.

Q. OTHER THAN THE NAME CHANGE, ARE THERE ANY DIFFERENCES BETWEEN THE DECOMMISSIONING RIDER AND THE BIG SANDY RETIREMENT RIDER?

A. No. The Company is proposing to change the name of Big Sandy Retirement Rider to the Decommissioning Rider to alleviate customer confusion regarding the purpose of the rider. There is no proposed change to the operation of the rider following the name change. References to the Decommissioning Rider in my testimony refer to both the historical operation of the Big Sandy Retirement Rider, the future billing of Decommissioning Rider rates and amortization of Big Sandy coal-related decommissioning costs. Under the Decommissioning Rider, the Company defers costs associated with the decommissioning of coal-related assets at the Big Sandy Plant. These costs are then added to the unamortized balance of the Decommissioning Rider regulatory asset. The unamortized balance of the Big Sandy decommissioning cost regulatory asset will be recovered through the billing of Decommissioning Rider rates.

Q. PLEASE DESCRIBE THE ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO THE DECOMMISSIONING RIDER IN SECTION V, EXHIBIT 2 W02.

A. Since the Company recovers the costs associated with the decommissioning of coal-related assets at Big Sandy through the Decommissioning Rider and not through base rates, any revenues and expenses related to the Decommissioning Rider must be removed from the Company's cost of service. Accordingly, I made the following adjustments relating to Decommissioning Rider revenue and expense for the test year ended February 28, 2017:

- A decrease to test year revenue of $16,524,933 in Accounts 440-444 to remove Decommissioning Rider revenue.
- A total decrease of $86,049 (retail jurisdictional amount) to test year O&M expense in Accounts 500, 506, 511, 512, 513 and 514 to remove Big Sandy coal-related O&M expense.
- An increase to test year O&M expense of $86,100 (retail jurisdictional amount) in Account 512 to remove the deferral of Big Sandy coal-related O&M expense.
- A removal of both test year ARO **accretion expense** of $2,566,149 (retail jurisdictional amount) in Account 411.1 and removal of the corresponding **deferral of test year ARO accretion expense** of $2,566,149 (retail jurisdictional amount) in Account 411.1, both related to Big Sandy coal-related ARO accretion expense. This removal of offsetting ARO accretion expense and the deferral of ARO accretion expense had no impact on test year cost of service.

- A decrease in test year amortization expense of $1,987,451 (retail jurisdictional amount) in Account 407.3 to remove amortization expense of the net Decommissioning Rider regulatory asset.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO THE BS1OR IN SECTION V, EXHIBIT 2 W06.

A. As discussed by Company Witnesses Sharp and Wohnhas, the BS1OR will be discontinued effective with the Company's change in base rates, and the related Big Sandy gas plant costs will be included in base rates going forward. Therefore, this adjustment for the test year ended February 28, 2017 removes all over-/under-recovery adjustments related to the gas operations of Big Sandy Plant that are currently being recovered through the BS1OR as described below:

- An increase in test year depreciation expense of $347,890 in Account 403 to remove a net BS1OR under-recovery adjustment.
- An increase in test year property tax expense of $341,289 in Account 408.1 to remove a net BS1OR under-recovery adjustment.
- A decrease in test year operation expense of $2,613,981 in Account 506 to remove a net BS1OR over-recovery adjustment.
- A decrease in test year maintenance expense of $25,332 in Account 512 to remove a net BS1OR maintenance expense over-recovery adjustment.
- A decrease in test year purchased power expense of $2,383,768 in Account 555 to remove a net BS1OR purchased power over-recovery adjustment.

The net decrease in expense of $4,333,902 for the BS1OR adjustments listed above is directly assigned to the Company's retail jurisdiction.

Q. HOW WILL THE REMAINING BS1OR UNDER-/OVER-RECOVERY BALANCE BE COLLECTED FROM/REFUNDED TO RATEPAYERS?

A. When new base rates are approved by the Commission that reflect recovery of Big Sandy gas plant costs in base rates, the Company will stop recording under-/over-recovery adjustments to the BS1OR regulatory asset/regulatory liability balance. At the time the Company files its next Kentucky base rate case, the Company will request recovery/return of the BS1OR regulatory asset/regulatory liability balance.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO THE DSM SURCHARGE IN SECTION V, EXHIBIT 2 W10.

A. The Company's DSM surcharge continues to recover lost revenue, incentives and program costs as previously approved by the Commission. This adjustment involves the removal of all DSM surcharge revenue and DSM O&M expense. The components of these net adjustments for the test year ended February 28, 2017 are described below:

- Decrease in test year other electric revenues of $12,563,569 in Account 456 including:
  - Removal of DSM Surcharge Revenue of $9,921,313.
  - Removal of DSM Incentive Revenue of $443,142.
  - Removal of DSM Lost Revenue of $5,060,246.
  - Addition for Recovery of Incentives, Lost Revenue of $2,861,132.

- Decrease in test year O&M expense of $7,060,189 in Account 908 related to program costs including:
    - Removal of DSM O&M Revenue Recovery of Program Costs of $7,060,181.
    - Removal of DSM O&M Expense of $6,821,771 for Program Costs.
    - Addition of DSM Deferral of $6,821,763 for Program Costs.

The net DSM adjustments result in reductions of $12,563,569 in test year revenue and $7,060,189 in test year expense. These reductions are all directly assigned to the Company's retail jurisdiction.

Q. DID YOU MAKE ANY COST OF SERVICE ADJUSTMENTS FOR CERTAIN RIDERS WITHOUT OVER-/UNDER-RECOVERY ACCOUNTING?

A. Yes. I made adjustments to test year cost of service for the Home Energy Assistance Program (HEAP) surcharge rider and the Kentucky Economic Development surcharge rider.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO HEAP IN SECTION V, EXHIBIT 2 W11.

A. For this adjustment, test year retail HEAP rider revenue of $246,772 recorded to Accounts 440-444 is removed and corresponding expense of $246,772 recorded as O&M expense to Account 908 is also removed. These HEAP revenue and expense adjustments are directly assigned to the Company's retail jurisdiction.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO THE COMPANY'S KENTUCKY

ECONOMIC DEVELOPMENT RIDER AS DESCRIBED IN SECTION V, EXHIBIT 2 W12.

A. For this adjustment, test year retail Kentucky Economic Development Rider revenue of $303,011 in Accounts 440-444 is removed and corresponding expense of $303,011 recorded as O&M expense to Account 908 is also removed. These Kentucky Economic Development Rider revenue and expense adjustments are directly assigned to the Company's retail jurisdiction.

Payroll and Benefit Adjustments

Q. ARE SPECIAL ADJUSTMENTS NECESSARY WHEN CALCULATING GOING LEVEL COST OF SERVICE ADJUSTMENTS FOR PAYROLL AND BENEFIT RELATED ISSUES?

A. Yes. As the operator and owner of an undivided 50% interest in the Mitchell Plant, the Company initially records 100% of all Mitchell Plant labor costs charged by Company employees. The Company then bills Wheeling Power Company ("Wheeling Power"), an affiliated AEP subsidiary company and owner of the remaining 50% undivided interest in the Mitchell Plant, Wheeling Power's share of Mitchell Plant labor costs.

In May 2015, AEP Generation Resources Inc. ("AEP Generation Resources"), an affiliated AEP subsidiary company, ceased operations at its Kammer Plant generating facility due to pending environmental regulations. Due to the proximity of Kammer Plant to Mitchell Plant, certain Company employees continue to work at the Kammer Plant during the ongoing shutdown of the plant facility. The Company initially records 100% of all Kammer Plant labor costs and then bills 100% of these labor costs to AEP Generation Resources.

In summary, all of the payroll and benefit cost of service adjustments discussed below are properly limited to Kentucky Power's ownership share of generation plant-related labor costs and are exclusive of amounts properly billed or allocated to AEP Generation Resources and Wheeling Power for their ownership shares of Kammer Plant and Mitchell Plant, respectively.

Q. DO YOUR PAYROLL AND BENEFIT COST OF SERVICE ADJUSTMENTS INCLUDE THE FORECASTED FINANCIAL IMPACT OF THE PROPOSED WORKFORCE ADJUSTMENT SPONSORED BY COMPANY WITNESS WOHNHAS?

A. No. None of the payroll and benefit adjustments that I describe below include the forecasted financial impact of the proposed addition in Company employees that is sponsored in this base rate case by Company Witness Wohnhas.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR PENSION AND OTHER POST EMPLOYEMENT BENEFITS (OPEB) (SECTION V, EXHIBIT 2 W23).

A. This adjustment accounts for known changes from test year pension and OPEB costs related to both active and inactive Company employees. This adjustment is based on 2017 forecasts, as provided by the Company's actuaries, Willis, Towers and Watson, less actual costs for the test year ended February 28, 2017. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of service increase for pension and OPEB expense is $148,679.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR EMPLOYEE GROUP BENEFITS (SECTION V, EXHIBIT 2 W24).

A. This adjustment accounts for known changes from test year values in medical, dental, life and long-term disability coverage for Company employees. The adjustment is based on the number of Company employees enrolled in each plan as of February 28, 2017 and actual cost per employee for 2017 compared to actual Company medical, dental, life and long-term disability coverage costs for the test year ended February 28, 2017. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the net cost of service increase for group benefit expense is $429,241.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENTS RELATED TO SEVERANCE EXPENSE (SECTION V, EXHIBIT 2 W31).

A. In 2015, the Company recorded estimates of severance expense and estimates of related taxes. Upon conclusion of 2015-related severance payments, these estimates were then trued-up in the Company's test year. This cost of service adjustment was made to decrease payroll expense for severance expense true-ups recorded in the test year that related to 2015 and also increase test year payroll tax expense payroll for true-ups in the test year that related to the 2015 severance. After applying corresponding retail allocation factors, the retail jurisdictional share of the decrease for severance expense is $35,433 and the retail jurisdictional share of the payroll tax expense increase is $2,363.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR THE COMPANY'S INCENTIVE COMPENSATION (SECTION V, EXHIBIT 2 W32).

A. Test year cost of service amounts include expenses for the three components of the Company's incentive compensation - Incentive Compensation Plan ("ICP"), Restricted Stock Units ("RSUs") and Performance Share Incentives ("PSIs"). Company Witness Carlin provides more details regarding the Company's annual incentive compensation plans.

For an incentive compensation cost of service adjustment, I compared forecasted 2017 costs and test year cost of service amounts for the three incentive compensation programs. For the component of the adjustment related to the Company's annual ICP program, I used forecasted ICP costs at a level of 1.0 of the incentive target to be paid to Company employees subject to meeting performance goals.

After applying corresponding O&M and retail allocation factors to the total cost of service adjustment for the Company's ICP, RSU and PSI incentive plans, the retail jurisdictional share of the cost of service decrease for incentive compensation is $1,525,035.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR EMPLOYEE MERIT INCREASES (SECTION V, EXHIBIT 2 W33).

A. This adjustment is based on annual merit increases and promotions as approved by the Company and provided by AEPSC's Human Resources department which are then prorated based on implementation dates of merit increases starting in April, May or June of 2017. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of service increase for merit increases is $826,770.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR ADDITIONAL OVERTIME COSTS RELATED TO MERIT INCREASES (SECTION V, EXHIBIT 2 W34).

A. To account for the impact of increased base pay on the Company's overtime expense, overtime costs for the test year ended February 28, 2017 were multiplied by approved the average merit increase percentages for 2017. These additional overtime costs were then prorated for 2017 based on corresponding 2017 merit implementation dates. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of service increase for overtime expense related to merit increases is $148,618.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR ANNUALIZED PAYROLL EXPENSE (SECTION V, EXHIBIT 2 W35).

A. This adjustment annualizes payroll expense by multiplying the Company's February 24, 2017 payroll (distributed on March 3, 2017) by 26 pay periods (the Company pays employees every other week). The resulting annualized 2017 payroll of $32,935,422 is compared to the Company's test year payroll costs of $33,283,239 resulting in an overall decrease of $347,817. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the payroll expense decrease is $244,837. This calculation to annualize payroll expense does not include overtime, severance payments or incentive payments.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR SAVINGS PLAN EXPENSE (SECTION V, EXHIBIT 2 W36).

A. For Company individuals participating in the AEP 401K retirement savings plan, the Company makes 100% matching contributions for each employee's first 1% of contributions of eligible compensation and 75% matching contributions for the next 5% of each employee's contributions of eligible compensation. The Company's 401K matching contributions are included as a test year expense for the Company. For 2017, the Company estimates that 401K retirement savings matching contributions will be 4.00% of employees' eligible earnings.

This cost of service adjustment for savings plan expense is determined by taking the net forecasted decrease related to changes in incentives, prorated merit increases, the impact of prorated merit increases on overtime and annualization of base payroll. This net decrease of $1,128,651 prior to application of O&M and retail allocation factors is then multiplied by the Company's forecasted savings plan rate of 4.00%, resulting in a $45,145 decrease in savings plan costs. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of the savings plan expense decrease is $31,779.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR MEDICARE TAX EXPENSE (SECTION V, EXHIBIT 2 W37).

A. The Company incurs Medicare tax expense for labor costs that include base pay, overtime and incentives. This cost of service adjustment for Medicare tax expense is determined by taking the net forecasted decrease related to changes in incentives, prorated merit increases, the impact of prorated merit increases on overtime and annualization of base payroll. This net decrease of $1,128,651 prior to application of O&M and retail allocation factors is then multiplied by the Medicare tax rate of 1.45%, resulting in a $16,365 decrease in savings plan expenses. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the savings plan expense decrease is $11,520.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR SOCIAL SECURITY TAX EXPENSE (SECTION V, EXHIBIT 2 W38).

A. The Company incurs Social Security tax expense for labor costs that include base pay, overtime and incentives. This cost of service adjustment for Social Security Tax is determined by taking the net forecasted decrease related to changes in incentives, prorated merit increases, the impact of prorated merit increases on overtime and annualization of base payroll. This net decrease of $1,128,651 prior to application of O&M and retail allocation factors is then multiplied by both the percent of 2016 Company salaries subject to 2016 Social Security tax and the Social Security tax rate of 6.20%, resulting in a $68,007 decrease in Company test year Social Security taxes. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the Social Security tax expense decrease is $47,877.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR SOCIAL SECURITY TAX BASE (SECTION V, EXHIBIT 2 W39).

A. The Company incurs Social Security tax expense of 6.2% on each employee’s combined base pay, overtime and incentive compensation up to the annual Social Security tax base. The tax base on which Social Security taxes are imposed increased from $118,500 in 2016 to $127,200 in 2017. Based on this tax base increase, the number of Company employees who earned more than $127,200 in 2016 and the Social Security tax rate of 6.20%, a net increase in Company Social Security tax expense of $36,949 was calculated. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of service increase due to the increase in the Social Security tax base is $26,009.

<u>Depreciation and Asset Retirement Obligation Adjustments</u>

Q. HOW DID THE COMPANY CALCULATE THE ANNUALIZATION OF DEPRECIATION EXPENSE USING COMMISSION APPROVED DEPRECIATION RATES AS OF FEBRUARY 28, 2017 IN SECTION V, EXHIBIT 2 W42?

A. To properly reflect depreciation expense based on property balances at the end of the test year and to reflect assets placed in service or retired during the test year, I calculated a depreciation annualization adjustment by multiplying the Company's February 28, 2017 gross plant balances for each functional class by corresponding depreciation rates used in February 2017. The resulting adjusted Current Annual Depreciation Expense is then compared to the corresponding 12 Month Test Year per Books Depreciation Expense, resulting in a total company $2,061,079 increase in depreciation expense. After applying corresponding allocation factors to each functional class' depreciation expense increase, the retail jurisdictional amount of the depreciation expense increase is $2,037,359.

Q. WHAT ADJUSTMENTS WERE MADE TO ARRIVE AT TEST YEAR PER BOOKS DEPRECIATION?

A. Adjustments were made to remove property balances and depreciation expense for the test year ended February 28, 2017 related to the Company's Mitchell Plant Flue Gas Desulfurization ("FGD") investment and Asset Retirement Obligations ("ARO"). Adjustments were also made to remove the deferral of the Big Sandy Unit 1 depreciation expense in connection with the BS1OR and to remove over-/under-recovery adjustments related to the Environmental Surcharge Rider.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANNUALIZATION OF DEPRECIATION EXPENSE RELATED TO THE MITCHELL PLANT FGD.

A. For the calculation of the annualization of depreciation in Section V, Exhibit 2 W42, February 28, 2017 Property Balances are reduced by $328,075,217 related to Mitchell Plant FGD plant in service while test year per books depreciation expense is also reduced by $9,978,418 for depreciation expense in the test year ended February 28, 2017 related to Mitchell Plant FGD plant in service. These adjustments are sponsored and described by Company Witness Elliott.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANNUALIZATION OF DEPRECIATION EXPENSE RELATED TO THE BS1OR.

A. For the calculation of the annualization of depreciation expense in Section V, Exhibit 2 W42, test year per books depreciation expense is increased by $347,890 to remove the deferral of depreciation expense related to the gas generation of Big Sandy Plant that is currently being recovered through the BS1OR. See Section V, Exhibit 2 W06.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANNUALIZATION OF DEPRECIATION EXPENSE RELATED TO THE ENVIRONMENTAL SURCHARGE RIDER.

A. For the calculation of the annualization of depreciation in Section V, Exhibit 2 W42, per books depreciation expense for the 12 months ended February 28, 2017 is decreased by $42,668 to remove the 2016 over-recovery adjustment related to the Environmental Surcharge rider as sponsored and described by Company Witness Elliott.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANUALIZATION OF DEPRECIATION EXPENSE RELATED TO ARO.

A. For the calculation of the annualization of depreciation expense in Section V, Exhibit 2 W42, February 28, 2017 Property Balances are decreased by $11,624,651 to remove ARO property balances while depreciation expense for the test year ended February 28, 2017 is reduced by $226,283 to remove test year ARO depreciation expense on Mitchell Plant. See Section V, Exhibit 2 W44 for the separate annualization of ARO depreciation expense.

Q. HOW DID THE COMPANY CALCULATE THE COST OF SERVICE INCREASE FOR PROPOSED BIG SANDY UNIT 1 DEPRECIATION RATES IN SECTION V, EXHIBIT 2 W43?

A. As a result of the Company's proposed update to Big Sandy Unit 1 depreciation rates as sponsored by Company Witness Cash, the cost of service adjustment in Section V, Exhibit 2 W43 increased the Company's depreciation expense for Big Sandy Unit 1 by $3,076,557. The increase in depreciation expense is calculated by multiplying February 28, 2017 Property Balances for Big Sandy Unit 1 by proposed Big Sandy Unit 1 depreciation rates. The calculated Proposed Annual Depreciation Expense of $9,038,132 is then compared to Big Sandy Current Annual Depreciation Expense of $5,914,724 that was calculated in Section V, Exhibit 2 W42, resulting in a total company $3,123,408 increase in depreciation expense. After applying a corresponding retail allocation factor to the total company Big Sandy depreciation increase, the retail jurisdictional amount of the depreciation increase is $3,076,557.

Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO DEPRECIATION EXPENSE IN SECTION V, EXHIBIT 2 W44.

A. The Company ARO depreciation annualization adjustment decreases depreciation expense by $3,818. The depreciation annualization adjustment is calculated by comparing forecasted ARO depreciation expense for the period March 2017 through February 2018 of $222,408 less per books ARO depreciation expense of $226,283 for the test year ended February 28, 2017, resulting in a total company ARO depreciation decrease of $3,876. The retail jurisdictional amount of the ARO depreciation decrease is $3,818 and is related to a Mitchell Plant ARO described below.

Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO ACCRETION EXPENSE IN SECTION V, EXHIBIT 2 W45.

A. This adjustment decreases other expense by $109,495. This decrease was calculated by comparing forecasted ARO accretion of $786,697 for the period March 2017 through February 2018 to per books ARO accretion expense of $897,859 for the test year ended February 28, 2017, resulting in a total company decrease of $111,162. The retail jurisdictional amount of the ARO accretion expense decrease is $109,495.

Q. WERE THERE ANY NEW ARO AMOUNTS RECORDED IN 2016?

A. Yes. In December 2013, the transfer of the 50% interest in Mitchell Plant to Kentucky Power was completed. Prior to the transfer, a particular wastewater pond was being used by both Kammer Plant and Mitchell Plant. Upon the transfer of the 50% ownership in Mitchell Plant to Kentucky Power, Mitchell Plant requested and was subsequently approved for 100% access to the wastewater pond. In the fourth quarter of 2016, accounting became aware that this wastewater pond has been serving the Mitchell Plant, but the ARO assets and liabilities did not transfer for accounting purposes from AGR (100% ownership) to Kentucky Power (50% ownership) and WPCo (50% ownership).

In December 2016, the Company recorded its 50% ownership share of ARO assets and liabilities related to the wastewater pond and $192,390 in accretion expense as shown by the following entry:

Account	Description	Debit	Credit
208	Paid in Capital	$1,173,797	
411.1	Accretion Expense	$192,390	
108	Net ARO Accumulated Depreciation		$112,397
230	ARO Liability		$1,253,790

The Company recorded an ARO liability of $1,253,790 as well as a credit to Account 108 for $112,397 related to a downward estimate in the recorded ARO liability.

Q. HOW DID THIS MITCHELL PLANT ARO ADDITION IMPACT YOUR COST OF SERVICE ADJUSTMENTS?

A. The $192,390 ARO accretion expense entry in Section V, Exhibit 2 W45 above to Account 411.1 included a one-time accretion expense adjustment of $124,989 recorded in the test year ended February 28, 2017 that was related to 2014 and 2015 and $67,401 in accretion expense that was related to 2016. As noted in Section V, Exhibit 2 W45, I have decreased ARO accretion expense by $111,162 which includes the removal of the 2014 and 2015 adjustment of $124,989 that was recorded in 2016 and an offset for a net increase in projected ARO accretion expense of $13,827.

With regard to the proposed decrease in cost of service for ARO depreciation in Section V, Exhibit 2 W44 of $3,818, this amount relates entirely to the depreciation of the new net ARO credit in Account 101/108 of $112,397 as shown in the table above. There are no other ARO depreciation changes.

VI. CAPITALIZATION AND RATE BASE ADJUSTMENTS

Q. ARE YOU SPONSORING ANY ADJUSTMENTS TO THE COMPANY'S CAPITALIZATION CALCULATION?

A. Yes. As shown in Section V, Exhibit 2 W53, I provided Company Witness Wohnhas with a capitalization adjustment to remove the total company net regulatory asset balance of $153,631,333 which is related to Big Sandy Unit 2. The Big Sandy Unit 2 coal assets are recorded as a regulatory asset in Account 182.3 and are being recovered through the Decommissioning Rider. After applying a corresponding retail allocation factor to this adjustment, the retail jurisdictional amount of the capitalization decrease is $151,326,863.

Q. ARE YOU SPONSORING ANY ADJUSTMENTS TO THE COMPANY'S RATE BASE CALCULATION?

A. Yes. As shown in Section V, Exhibit 2 W53, I also provided Company Witness Wohnhas with a rate base adjustment to add accumulated deferred taxes of $82,681,209 related to Big Sandy Unit 2 coal assets. After applying a corresponding retail allocation factor to this adjustment, the retail jurisdictional amount of the rate base increase is $81,440,991.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

STEPHEN L. SHARP JR.

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Stephen L. Sharp, being duly sworn, deposes and says he is a Regulatory Consultant, for Kentucky Power Company and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Stephen L. Sharp

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen L Sharp, this the 22nd day of June 2017.

Judy K Rosquist
Notary Public

Notary ID Number: 571144

My Commission Expires: January 23, 2021

DIRECT TESTIMONY OF
STEPHEN L. SHARP JR., ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
STEPHEN L. SHARP JR., ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TITLE.

A. My name is Stephen L. Sharp, Jr., and I am a Regulatory Consultant for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. In 2001, I received a Bachelor of Arts degree in Integrated Strategic Communications from the University of Kentucky. In 2002, I accepted a position with American Electric Power's ("AEP") Customer Service Department in Hurricane, West Virginia, where I held various positions. In 2014, I transferred from Hurricane to my current position within Kentucky Power's Regulatory Services Department.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH KENTUCKY POWER?

A. My primary responsibility is to support the Company's regulatory activities. Part of this responsibility is to manage the Company's tariffs and regulatory filings, including the Demand Side Management filings and the monthly Fuel Adjustment Clause reports, and to support other members of Kentucky Power's Regulatory Services Department.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe the proposed changes to Kentucky Power's tariffs. In addition, I present certain adjustments to test year revenues and operating expenses.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I am sponsoring **EXHIBIT SLS-1** which provides examples of the Company's bill forms proposed in Case No. 2017-00231, and **EXHIBIT SLS-2** which details the calculation of the proposed new cable television pole attachment fees.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

IV. TARIFF CHANGES

Q. PLEASE DESCRIBE THE TARIFF CHANGES THAT THE COMPANY IS PROPOSING IN THIS CASE.

A. The Company is proposing to add new tariffs, eliminate tariffs that are no longer required, and modify certain existing tariffs. Each category of changes is described below. The Company's proposed tariff sheets are included as Exhibit D to Section II of the Company's Application. A set of the Company's current tariff sheets marked to show the proposed changes is included as Exhibit E to Section II of the Company's Application. The proposed effective date of the Company's revised tariffs is July 29, 2017; however, if the Commission suspends the proposed tariffs pursuant to KRS

278.190, the effective date of the revised tariffs will be December 29, 2017, the first day of the January 2018 billing cycle.

New Tariffs

Q. WHAT NEW TARIFFS IS THE COMPANY PROPOSING?

A. The Company is proposing to add the following new tariffs:

- Kentucky Economic Development Surcharge (Tariff K.E.D.S.), Sheet 24-1;
- Home Energy Assistance Program (Tariff H.E.A.P.), Sheet 25-1;
- General Service (Tariff G.S.), Sheet 7-1; and
- Residential Demand-Metered Electric Service (Tariff R.S.-D.), Sheet 6-14.

Q. KENTUCKY POWER IS ALREADY ADMINISTERING THE K.E.D.S AND H.E.A.P. PROGRAMS. WHY IS THE COMPANY PROPOSING TO ADD STAND-ALONE TARIFF SHEETS FOR THESE PROGRAMS?

A. Currently, the tariff sheets for each of Kentucky Power's tariff classes include a brief summary of each applicable surcharge and rider, along with references to the individual tariff sheets, if any, governing each surcharge and rider. Only the K.E.D.S. and H.E.A.P. surcharges do not have stand-alone tariff sheets. Creating stand-alone tariff sheets for the K.E.D.S. and H.E.A.P. surcharges allows the Company to simplify the Company's tariff class sheets and to provide additional information to customers about the K.E.D.S. and H.E.A.P. surcharges.

Q. IN ADDITION TO CREATING A STAND-ALONE TARIFF SHEET, IS KENTUCKY POWER PROPOSING ANY OTHER CHANGES TO THE K.E.D.S. PROGRAM?

A. Yes. The Company is proposing to increase the K.E.D.S. surcharge amount from $0.15 to $0.25 per meter per month to provide additional funds to underwrite economic development initiatives in Kentucky Power's service territory. Kentucky Power will match the increased funding on a dollar-for-dollar basis. Additional information regarding the K.E.D.S. program, including the need for increased funding, is provided in the testimonies of Company Witnesses Satterwhite and Hall.

Q. IS KENTUCKY POWER PROPOSING ANY CHANGES TO THE H.E.A.P. PROGRAM?

A. Yes. The Company is proposing to increase the H.E.A.P. surcharge amount from $0.15 to $0.20 per meter per month to provide additional funds to assist low income households with the cost of home energy. The Company will match the increased funding on a dollar-for-dollar basis. The H.E.A.P surcharge applies only to residential customers. Additional information regarding the change to the H.E.A.P. surcharge amount is provided in the testimony of Company Witness Wohnhas.

Q. PLEASE DESCRIBE THE NEW GENERAL SERVICE TARIFF.

A. Kentucky Power is proposing to combine its Small General Service ("Tariff S.G.S.") and Medium General Service ("Tariff M.G.S.") Tariffs, including each tariffs Load Management Time of Day Provision, into a single, new General Service tariff ("Tariff G.S."). Additional information about the new Tariff G.S. is included in the testimony of Company Witness Vaughan.

Q. PLEASE EXPLAIN THE PROPOSED RESIDENTIAL DEMAND-METERED ELECTRIC SERVICE TARIFF.

A. The Company is proposing an optional tariff designed to reward customers for shifting usage away from peak time periods during the year. Additional information regarding this pilot tariff is provided in the testimony of Company Witness Vaughan.

<u>Tariff Eliminations</u>

Q. IS KENTUCKY POWER PROPOSING TO ELIMINATE ANY TARIFFS?

A. Yes. The Company is proposing to eliminate the following tariffs:

- Asset Transfer Rider (Tariff A.T.R.), Sheet 36-1 through Sheet 36-2;
- Big Sandy Unit 1 Operation Rider (Rider B.S.1.O.R.”), Sheet 39-1 through Sheet 39-2;
- Small General Service (Tariff S.G.S.), Sheet 7-1 through Sheet 7-4;
- Medium General Service (Tariff M.G.S.), Sheet 8-1 through Sheet 8-4;
- Pilot Public School Service (Tariff K-12 School), Sheet 9-9 through Sheet 9-12; and

Q. WHY IS KENTUCKY POWER PROPOSING TO ELIMINATE THE ASSET TRANSFER RIDER?

A. The Asset Transfer Rider was an interim tariff under which the Company recovered $44 million in annual revenues between January 1, 2014 and June 29, 2015 (the effective date of rates approved in the Company’s first base rate case after the Mitchell Transfer). The additional $44 million in annual revenue and the tariff were approved by the Commission in its October 7, 2013 Order in Case No. 2012-00578. The Company has recovered the full amount the rider was designed to collect and the rider is no longer necessary. Kentucky Power last billed this rider in November 2015.

Q. WHY IS KENTUCKY POWER PROPOSING TO ELIMINATE THE BIG SANDY UNIT 1 OPERATIONS RIDER?

A. The B.S.1.O.R. is another interim tariff. With the planned conversion of Big Sandy Unit 1 from a coal-fired to a natural gas-fired unit, and recovery of the coal-related retirement costs at the Big Sandy plant through the Big Sandy Retirement Rider, the Company proposed the B.S.1.O.R. to recover certain of the non-fuel operating costs of Big Sandy Unit 1, along with a return on and of the capital investment required to convert Big Sandy Unit 1, during the transition. Kentucky Power completed the conversion of Big Sandy Unit 1 to a natural gas-fired unit and is proposing to recover the costs currently recovered through the B.S.1.O.R. through base rates per the Commission's order in Case No. 2014-00396.

While it will no longer track and recover Big Sandy Unit 1 operating costs going forward, the B.S.1.O.R. will have an under or over recovery balance when new rates becoming effective in this case. To allow for the recovery or credit of any over or under recovery balance, the Company is requesting that the Commission authorize accounting practices that will allow the Company to track and defer, as a regulatory asset or liability, any under or over recovery balance until the Company's next rate case. Additional information regarding the Company's proposed accounting treatment of the B.S.1.O.R. under or over recovery balance is provided in the testimony of Company Witness Wohnhas.

Q. WHY IS KENTUCKY POWER PROPOSING TO ELIMINATE ITS SMALL GENERAL SERVICE AND MEDIUM GENERAL SERVICE TARIFFS?

A. As described above, the Company is proposing to combine Tariffs S.G.S. and M.G.S. into a new Tariff G.S. If Tariff G.S. is approved, the Company will eliminate Tariffs S.G.S. and M.G.S. accordingly. The existing Small General Service – Time of Day

("Tariff S.G.S. – T.O.D.") and Medium General Service – Time of Day ("Tariff M.G.S. – T.O.D.") tariffs will remain as stand-alone tariffs.

Q. PLEASE EXPLAIN WHY PILOT TARIFF K-12 SCHOOL IS BEING DELETED.

A. Pilot Tariff K-12 School was implemented as part of a settlement in Kentucky Power's last rate case, Case No. 2014-00396, as a pilot program for certain classes of schools to obtain service at a reduced rate. The rate was designed to reduce on an annual basis the total non-fuel revenue recovered from the schools eligible to take service under the pilot tariff by $500,000 from the amount they otherwise would pay by taking service under the Large General Service Tariff ("Tariff L.G.S."). The settlement provided that, based upon load research data, the Company would address in its next general rate case the continuation of the pilot tariff. Based upon the Company's load research, Kentucky Power has determined that the pilot tariff should no longer be offered as these customers would be better served under Tariff L.G.S. Additional information regarding the operation of Pilot Tariff K-12 School, the relevant load research, and the basis for the Company's decision to eliminate the tariff are provided by Company Witness Vaughan.

Tariff Modifications

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO ITS EXISTING TARIFFS IN THIS PROCEEDING?

A. Yes. In addition to the rate changes sought in this proceeding, the Company is proposing a number of textual changes to its current tariffs. I do not address minor text changes. Substantive changes to the tariffs are described below.

Terms and Conditions of Service (Sheet 2-1 through 2-22)

Q. IS THE COMPANY PROPOSING TO MODIFY ITS TERMS AND CONDITIONS OF SERVICE?

A. Yes. Kentucky Power is modifying Sections 1, 2, 4, 5, 8, and 18 of its current Terms and Conditions of Service. The Company also is adding new Sections 6 and 22. Because of the new sections to the Company's terms and conditions, references to section number in my testimony are to the section number after the new section additions.

Section 1: Application (Sheet 2-1)

Q. DESCRIBE GENERALLY THE CHANGES BEING PROPOSED TO SECTION 1 OF KENTUCKY POWER'S TERMS AND CONDITIONS OF SERVICE.

A. Kentucky Power is proposing to amend Section 1 to describe more fully the process for applying for service. Section 1 as amended now provides that:

- Applications may be made in writing, online, or via telephone for customers seeking electric service;
- Requests for electric service must be in a customer's legal name;
- The Company may require verification of the customer's identity, legal occupancy (i.e. proof of ownership or lease), or other requested information before service will be provided; and
- The Company may reject any request for service in accordance with 807 KAR 5:006 Section 15.

These requirements are intended to limit fraudulent applications and to prevent persons who have had their service disconnected from reapplying under a different name or the name of a household member without satisfying past due amounts.

Q. DO THE PROPOSED MODIFICATIONS CHANGE THE CURRENT APPLICATION PROCESS OR IMPOSE ADDITIONAL REQUIREMENTS?

A. No.

Q. HAS THE COMPANY EXPERIENCED PROBLEMS WITH FRAUDULENT APPLICATIONS?

A. Yes. On occasion, persons will seek to establish service using a name or social security number other than their own. In addition, customers who have had their service disconnected have, on occasion, attempted to reestablish service using a fraudulent name or the name of a person residing at the service address at the time the service was disconnected.

Q. HOW WILL THE NEW PROVISIONS OF SECTION 1 ADDRESS THIS PROBLEM?

A. The requirements are expected to limit fraudulent applications and efforts to avoid financial responsibility for past due amounts.

<u>Section 2: Inspections (Sheet 2-1)</u>

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE INSPECTION SECTION OF THE COMPANY'S TERMS AND CONDITIONS OF SERVICE.

A. Kentucky Power is proposing a change to the provision to allow it to require a state inspection before reconnection of service where the Company has de-energized service because of tampering or theft of service. Because tampering and theft of service can damage the integrity of the Company's and the customer's facilities, the required inspection will help ensure service may be safely restored, and that the restored service meets state electrical safety requirements.

<u>Section 4: Deposits (Sheets 2-2 through 2-4)</u>

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE DEPOSIT SECTION OF THE COMPANY'S TERMS AND CONDITIONS OF SERVICE.

A. The Company will no longer consider an applicant's credit history with national credit bureaus as a reason to waive a deposit.

Q. WHY IS THE COMPANY PROPOSING TO MAKE THIS CHANGE?

A. Kentucky Power requires a deposit to secure timely payment of electric bills by the customer. In determining whether to waive the deposit, the Company investigates the prospective customer's payment history to determine whether there is a risk of non-payment. This investigation seeks to determine whether a prospective customer is consistently late with their utility bill payments, has had their service disconnected frequently or, conversely, has an excellent payment history. Credit bureau reports do not necessarily provide the Company with sufficient information to evaluate a prospective customer's payment history because not all instances that would counsel against waiving a deposit are reflected in credit reports. For example, Kentucky Power does not notify national credit bureaus of payment issues with a customer unless that customer closes his or her account without paying the final balance.

Q. WILL ALL CUSTOMERS NOW BE REQUIRED TO PROVIDE A DEPOSIT WITH THIS CHANGE?

A. No. The Company may still waive the deposit requirement if a customer has satisfactory payment history with Kentucky Power, another Kentucky Power customer with satisfactory payment history is willing to guarantee payment the customer, or, if a customer has never had service with Kentucky Power, the customer can provide evidence of a satisfactory payment history with another utility.

Q. WHAT DOES THE COMPANY CONSIDER A SATISFACTORY PAYMENT HISTORY WITH THE COMPANY?

A. The Company's Terms and Conditions under Deposit (Sheet 2-3) defines "satisfactory payment history with the Company" as the timely payment of all bills and the absence of disconnections of service for nonpayment, late notices, breached payment arrangements, returned payments, or history of meter diversion or theft of service.

Section 5: Payments (Sheet 2-4 through Sheet 2-5)

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE BUDGET PAYMENT PLAN.

A. Kentucky Power is requesting a deviation from 807 KAR 5:006, Section 14(2)(a) to allow it to:

- limit months when a customer can sign up for the Budget Payment Plan. Currently, a customer can sign up for the Budget Payment Plan at any time as long as they are current on their electric bill. The Company is requesting a change that would only allow customers to sign up for the Budget Payment Plan from April through December.

- alter, with customer approval, the annual "settle up" months for those customers whose settle up month currently falls in December, January, or February so that the settle-up month occur in a non-winter month.

Q. WHY IS THE COMPANY REQUESTING THIS DEVIATION?

A. Customers receiving service under the Budget Payment Plan are charged a fixed monthly rate based on either historical or estimated usage. In accordance with 807 KAR 5:006, Section 14(2)(a), the Company must issue bills to customers under the Budget Payment Plans that adjust their accounts so as to bring them current once each twelve month-period. Kentucky Power adjusts accounts by including a "settle up" amount that coincides with the anniversary of a customers' entry onto the Budget Payment Plan. The customers settle up month can include a charge if the customers use more electricity than was budgeted for or a credit if they use less.

The Company is proposing this deviation following its review of the Company data from Budget Payment Plan customers whose settle up month occur during the winter months. The Company found that many customers experienced large balances due to a combination of high winter bills and their settle up month balance. Through the deviation, the Company will prevent settle up months from occurring during periods of high winter heating bills.

Q. WHAT DOES THE CUSTOMER PAY DURING THE SETTLE UP MONTH?

A. In addition to the Budget Payment Plan settle up balance, the customer also pays the actual electric bill for the month. The combination of these payments brings customers' accounts current. Payments under the Budget Payment Plan begin again the following month with an adjusted monthly payment amount incorporating usage information developed during prior years.

Q. WHY CAN A CUSTOMER NOT CHOOSE WHEN THE SETTLE UP MONTH WILL OCCUR?

A. Settle up months are determined when a customer signs up for the Budget Payment Plan. For an example, if a customer signs up in February, the settle up month would occur 12 months later in January.

Q. DOES THE COMPANY CURRENTLY REVIEW ACCOUNTS WITH BUDGET PAYMENT PLANS?

A. Yes. The Company reviews usage and billing information for customers on the Budget Payment Plan approximately every 6 months. During this review, the Company may adjust monthly budget payments to eliminate the possibility of a large settle up month. If there are any adjustments to monthly payments under a Budget Payment Plan, the customer is provided a month’s notice before the change.

Q. WILL THE COMPANY’S PROPOSED DEVIATION REDUCE OPTIONS FOR CUSTOMER’S DURING THE WINTER MONTHS?

A. No. The Company still offers the Average Monthly Plan (AMP), which a customer can still take advantage of at any time during the year. While similar to the Budget Payment Plan, the AMP allows customers to pay their twelve-month bill average each month. On the 12th month, or settle up month, any balance or credit that has accumulated would be divided up over the customer’s next twelve bills to be paid in addition to a customer’s bill. The Company recommends the AMP for customers who wish to avoid the potentially dramatic settle up month amounts under the Budget Payment Plan.

Q. IF THE COMMISSION APPROVES THIS DEVIATION, HOW WILL THE COMPANY ADDRESS CUSTOMERS WHO CURRENTLY HAVE A BUDGET PAYMENT PLAN WITH A SETTLE UP DURING THE WINTER MONTHS?

A. If approved, the Company will engage customers with winter settle-up months with the goal of moving those customers' settle up months to November or March. Presently, Kentucky Power has over 5,300 customers who have Budget Payment Plans with settle up months during the months of December, January and February. The Company will work with those customers to arrive on a new settle up month that works best for each customer. Customers who wish to change their settle up month must be current on their accounts. The Company is planning to reach out to these customers by automated calls and community outreach meetings.

Q. IF APPROVED, WHEN WOULD THE COMPANY BEGIN ITS DEVIATION TO 807 KAR 5:006, SECTION 14(2)(a)?

A. The deviation would begin at the conclusion of this proceeding.

Q. WILL THE COMPANY BE MAKING ANY OTHER CHANGES IN THE PAYMENTS SECTION IN THE COMPANY'S TERMS AND CONDITIONS OF SERVICE?

A. Yes. The Company is proposing to clarify its Payments section by removing the phrase that all bills are payable "at the business offices or authorized collection agencies" in the first paragraph of Subsection C on Sheet 2-5. This change is necessary for two reasons. First, the Company no longer offers the option of paying at the Company's local offices. Second, the current language ignores the variety of other bill payment options available to the Company's customers. Customers may pay their bills at local authorized payment centers, over the phone, online at www.kentuckypower.com, through automatic deductions from the customer's bank account each month, or by mailing in a payment to the Company.

<u>New Section 6: Payment Arrangements (Sheet 2-5)</u>

Q. PLEASE DESCRIBE THE PROPOSED ADDITION OF THE PAYMENT ARRANGEMENTS SECTION TO THE COMPANY'S TERMS AND CONDITIONS OF SERVICE.

A. The Company is proposing to add a new section in its Terms and Condition to outline reasonable provisions consistent with the Commission's regulations to be included in customer partial payment plans. These provisions include:

- Notification that payment arrangements may be negotiated as late as the day immediately prior to the termination date printed on a customer's termination notice;
- Limiting payment arrangements to the current balance and balances up to 59 days past due;
- Requiring any balance 60 days or older be paid in full at least one business day prior to the date of the effective date of the payment arrangement;
- Requiring that all past partial payment plan arrangements be satisfied before entering into a new payment arrangement;
- Excluding deposits from payment arrangements;

- Reserving the Company's right to decline third-party pledges that cannot be verified to pay some or all of a customer's obligation;
- Noting that customers entering into payment arrangements will be advised in writing or by telephone of the date and amount of payments due, and that service may be terminated without additional notice if the customer fails to meet the agreed obligations under the payment arrangement;
- Noting that it is the responsibility of the customer presenting a Medical Certificate to contact the Company to negotiate a payment arrangement based upon the customer's ability to pay; and
- Noting that customers presenting Certification for Health and Family Services must do so during the initial 10 day termination notice period. As a condition of the 30 day extension, the customer shall exhibit good faith by entering into a payment arrangement.

Q. WHAT IS THE PURPOSE OF ADDING THESE PROVISIONS?

A. Partial payment plans are authorized under 807 KAR 5:006 Section 14(2), and the tariff terms identify the provisions that will be included by the Company in a partial payment plan. The new section provides a readily available reference for some of the important terms governing payment arrangements. By adding this language to the tariff, the Company hopes to further inform customers that the Company will be able to assist in situations when a payment arrangement may be needed by the customer.

Q. WHY ARE CUSTOMERS REQUIRED TO ENTER INTO A PAYMENT ARRANGEMENT PRIOR TO THE TERMINATION DATE PRINTED ON THE CUSTOMER'S TERMINATION NOTICE?

A. The one-day prior to termination cut-off date requirement is reasonable and necessary to avoid unnecessary trips by Company field personnel to customers who enter into last minute partial payment plants. The Company notifies customers facing disconnection by letter, phone, and mobile alerts (if a customer has signed up for this option) of the need prior to disconnection to pay past due amounts, or, if they qualify, to call and make payment arrangements. Thus, customers have adequate time to make payment arrangements prior to the disconnection date.

The Company dispatches its meter servicers on multiple service tickets at the beginning of the day. It is not uncommon for a customer to call to seek a payment arrangement following the meter servicer's arrival at the customer's address or while the meter servicer is in route. Requiring that a payment arrangement be consummated prior to the date of termination of service allows the Company to avoid the expense, which is reflected in base rates, associated with unnecessary field trips. In addition, avoiding such trips frees up personnel to work service calls.

Q. WHY IS THE COMPANY REQUIRING CUSTOMERS TO ADDRESS ANY BALANCES 60 DAYS OR OLDER PRIOR TO A PAYMENT ARRANGEMENT BEING ESTABLISHED?

A. Typically, a customer's deposit covers two months of charges. Accordingly, it is important that all balances not secured by the deposit be paid prior to extending further credit through a payment arrangement. Doing so helps limit the Company's bad debt expense that ultimately is paid by other customers.

Q. WHY WOULD CUSTOMERS NOT HAVE THEIR SERVICE TERMINATED PRIOR TO THE ACCOUNTS BECOMING SIXTY DAYS PAST DUE?

A. In most cases a customer would be disconnected prior to the account becoming more than 60 days in arrears. There are situations where customers can extend their service even though they are sixty or more days in arrears. For example, a customer who obtains a medical certificate may continue service for thirty days by obtaining a medical certificate pursuant to 807 KAR 5:006, Section 15(3) despite having an account 30 days in arrears. This provision does not affect the efficacy of medical certificates.

Q. WHY WOULD THE COMPANY RESERVE THE RIGHT TO TERMINATE SERVICE WHERE IT CANNOT VERIFY THE LEGITIMACY OF A THIRD PARTY PLEDGE TO ASSUME RESPONSIBILITY FOR ALL OR PART OF A PAST DUE ACCOUNT?

A. Kentucky Power works with local agencies, churches, and other nonprofit organizations who provide assistance for unpaid utility bills. On occasion, the Company determines a pledge is fraudulent. Because of this, it is good business practice to verify all third-party offers of assistance.

<u>Section 8: Customer Liability (Sheet 2-7)</u>

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS TERMS AND CONDITIONS RELATING TO CUSTOMER LIABILITY?

A. Yes. The Company is proposing to add language clarifying that if a customer's service is terminated for cause, it may assess all applicable charges to that customer for the period between the date ending the customer's last billing period and the date of the termination and for any damage to Company equipment.

Section 12: Billing Form (Sheet 2-7)

Q. IS THE COMPANY PROPOSING TO CHANGE ITS BILLING FORMS?

A. Yes, but not in this case. On June 12, 2017, the Company filed an application with the Commission in Case No. 2017-00231 seeking authority to amend it terms and conditions of service to implement a new bill format. The Company requested a decision by September 15th, 2017 to permit the Company sufficient time to debut the new bill format December 1, 2017. If new bill forms are approved in Case No. 2017-00231, the Company will update its proposed tariffs in this case to reflect the new billing forms. Examples of the new bill forms that are being proposed in Case No. 2017-00231 are provided in **Exhibit SLS-1**.

Section 18: Denial or Discontinuance of Service (Sheet 2-10)

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS TERMS AND CONDITIONS RELATING TO THE DENIAL OR DISCONTINUANCE OF SERVICE?

A. Yes. The Company is clarifying that it reserves the right to refuse service when a customer or any member of the customer's household is indebted to the Company for any service rendered at any location. The modification also permits the denial or discontinuance of service if any member of the customer's household is indebted to the Company for service rendered at that location.

Q. WHY IS THIS CLARIFICATION NECESSARY?

A. This clarification is necessary to make clear that customers that are indebted to the Company for services rendered cannot simply close the account in their name and open an account at the same location in the name of a different member of the same household.

<u>Section 19: Employee's Discount (Sheet 2-11)</u>

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE EMPLOYEE'S DISCOUNT SECTION OF THE COMPANY'S TERMS AND CONDITIONS OF SERVICE.

A. The Company is proposing to eliminate employee discounts for residential electric service. Additional information regarding the elimination of the employee discount is provided in the testimony of Company Witness Satterwhite

<u>New Section 22: Kentucky Power's Mobile Alerts Service (Sheet 2-13 through Sheet 2-16)</u>

Q. PLEASE DESCRIBE THE COMPANY'S MOBILE ALERTS SERVICE.

A. Kentucky Power's mobile alert service is an optional service where customers can receive an email or text message with information concerning outages, estimated restoration times, account billings, and payments.

Q. IS THERE A CHARGE FOR CUSTOMERS TO SIGN UP FOR THIS SERVICE?

A. No. Kentucky Power offers mobile alerts as a free service to its customers. However, standard text message and data rates charged by the customer's cellular service providers may apply. The standard text message and data rates will vary based upon the Customer's mobile data plan.

Q. HOW MANY CUSTOMERS HAVE ENROLLED IN THE COMPANY'S MOBILE ALERT SERVICE?

A. Since its inception in March 2015, over 15,800 customers have enrolled to receive mobile alerts.

Q. WHAT TARIFF CHANGES IS KENTUCKY POWER PROPOSING IN CONNECTION WITH ITS MOBILE ALERT SERVICE?

A. Kentucky Power is adding a new section to its Terms and Conditions to describe the scope and nature of the optional mobile alert service. The new mobile alerts section outlines what alerts will be provided through the service, limitations on the Company's liability relating to the mobile alert service, and clarifies that the mobile alerts are supplemental to and do not replace existing, standard communication formats such as billing statements and disconnection notices. The new section also clarifies that to the extent there are any discrepancies between the mobile alerts and the standard communications, the information provided by the standard communication prevails.

Q. ARE THE TERMS AND CONDITIONS OF THE MOBILE ALERT SERVICE AVAILABLE ELSEWHERE?

A. Yes. They are available on the Company's website and customers must acknowledge reviewing the terms and conditions prior to enrolling. Adding the language to the tariff permits customers to review the applicable terms and conditions before enrolling.

Other Tariffs

Capacity and Energy Control Program (Sheet 3-1 through Sheet 3-6)

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO THE CAPACITY AND ENERGY CONTROL PROGRAM TARIFF.

A. The Company is proposing to modify the language in its Capacity and Energy Control Program tariff to update and simplify the description of the program.

<u>Standard Nominal Voltages (Sheet 4-1)</u>

Q. PLEASE DESCRIBE THE CHANGES TO THE STANDARD NOMINAL VOLTAGES PROVIDED BY THE COMPANY.

A. The Company has updated its description of the standard voltages provided for customer classes other than residential to include additional available voltages.

<u>Fuel Adjustment Clause (Tariff F.A.C.) (Sheet 5-1 through Sheet 5-2)</u>

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS FUEL ADJUSTMENT CLAUSE TARIFF?

A. Yes. The Company is proposing changes to identify additional fuel-related PJM billing line items that will be included as fuel costs in the calculation of the fuel adjustment factor. Additional information regarding the changes to Tariff F.A.C. is included in the testimony of Company Witness Rogness.

<u>Contract Service – Interruptible Power (Tariff C.S.-I.R.P.) (Sheet 12-1 through 12-4)</u>

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO TARIFF C.S.-I.R.P.

A. The Company is deleting the section of Tariff C.S.-I.R.P. relating to term of contracts for customers taking service under the tariff.

Q. WHY IS THE COMPANY DELETING THE SECTION RELATING TO TERMS OF THE CONTRACTS UNDER TARIFF C.S.-I.R.P.?

A. Customers taking advantage of the rates available under Tariff C.S.-I.R.P. must also be under contract for service under Tariff I.G.S. (Industrial General Service). The I.G.S. contract will provide the term.

<u>Outdoor Lighting (Tariff O.L.); Street Lighting (Tariff S.L.) (Sheet 14-1 through 15-4)</u>

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO THE COMPANY'S OUTDOOR AND STREET LIGHTING TARIFFS.

A. Kentucky Power is proposing two changes to these tariffs. First, the Company is clarifying both tariffs to limit the availability of outdoor and street lighting to customers whose accounts are current. Second, the Company is segregating the base fuel portion of the overhead and street lighting rates.

Q. WHY IS THE COMPANY PROPOSING THE CHANGE TO THE AVAILABILITY OF SERVICE UNDER THESE TARIFFS?

A. Outdoor and street lighting is an optional service that is provided at an additional charge. It is not appropriate to provide additional services to customers who are delinquent in meeting their existing financial obligations the Company.

Q. WHY IS THE COMPANY SEPARATING THE BASE FUEL CHARGE FOR STREET AND OVERHEAD LIGHTING CUSTOMERS?

A. Kentucky Power is separating its base fuel charge to conform its billing practices with the requirements of its internal billing software. Currently, the rate charged by street and outdoor lighting customers includes base fuel costs as a component of the total rate. This change is not an additional charge, but instead simply a delineation of the components of the prior rate. The per lamp rates charged under these tariffs have been adjusted to account for the separate delineation of the base fuel component of the rate.

Q. CAN YOU PROVIDE A COMPARATIVE EXAMPLE OF THE CURRENT RATE STRUCTURE COMPARED TO THE PROPOSED STRUCTURE?

A. Yes. **SLS Table 1** below provides a comparison of the proposed rate structure for Tariff Code 094 against the current rate structure. While the proposed rate structure would bring variations in charges from month to month corresponding to the monthly variations in the kWh's used to calculate the base fuel charge, customers would see no impact annually with this change.

SLS - Table 1

Comparison of Tariff Code 094 - 100 Watt High Pressure Sodium					
Month	Monthly kWh	Tariff 094 Base Fuel Rate Included (Current Structure)	Tariff 094 Base Fuel Rate Excluded (Proposed Structure)	Base Fuel Charge (2) * .02725	Monthly Difference ((4)+(5))-(3)
(1)	(2)	(3)	(4)	(5)	(6)
January	51	$ 10.60	$ 9.50	$ 1.39	$ 0.29
February	43	$ 10.60	$ 9.50	$ 1.17	$ 0.07
March	43	$ 10.60	$ 9.50	$ 1.17	$ 0.07
April	36	$ 10.60	$ 9.50	$ 0.98	$ (0.12)
May	32	$ 10.60	$ 9.50	$ 0.87	$ (0.23)
June	29	$ 10.60	$ 9.50	$ 0.79	$ (0.31)
July	31	$ 10.60	$ 9.50	$ 0.84	$ (0.26)
August	35	$ 10.60	$ 9.50	$ 0.95	$ (0.15)
September	39	$ 10.60	$ 9.50	$ 1.06	$ (0.04)
October	45	$ 10.60	$ 9.50	$ 1.23	$ 0.13
November	48	$ 10.60	$ 9.50	$ 1.31	$ 0.21
December	52	$ 10.60	$ 9.50	$ 1.42	$ 0.32
End of Year Difference					**$ (0.01)**

<u>Cable Television Pole Attachment (Tariff C.A.T.V.) (Sheet 16-1 through Sheet 16-5)</u>

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO TARIFF C.A.T.V.

A. The Company is proposing to change its pole attachment rate for cable television operators. For attachments on a two user pole, the Company is proposing to increase the rate from $7.21 to $11.97 per attachment per year, and to increase the rate for attachments on a three user pole from $4.47 to $7.42 per attachment per year. The Company last changed its pole attachment rates in 2006 in Case No. 2005-00341.

Q. WHY IS THE COMPANY PROPOSING TO INCREASE ITS CABLE TELEVISION POLE ATTACHMENT RATES?

A. The Company has not updated its pole attachment rates since its 2005 rate case. Kentucky Power's pole attachment rates are based in large part on the cost of purchasing, installing, and maintaining the Company's poles. Those costs have increased in the intervening eleven years. An operator attaching equipment to the Company's poles should pay a fair share of the costs associated with the services it is receiving.

Q. HOW WERE THE PROPOSED ATTACHMENT RATES DEVELOPED?

A. The proposed attachment rates were developed using the same methodology the Company has used in prior cases with the Commission involving CATV attachments, most recently in Case No. 2005-00341. The data used in the Company's calculation comes from Kentucky Power's most recent FERC Form 1 filing. **EXHIBIT SLS-2** provides the calculation of the rates.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO THE CATV TARIFF?

A. The Company is revising the Default or Non-Compliance section of the tariff. Under the current tariff the Company has the right to remove a defaulting operator's facilities at the operator's expense. The revised tariff places the burden on the operator to remove its facilities within 30 days of the issuance by the Company of a notice of termination. If the operator fails to act within the 30 day period, the Company may remove the attachments at the operator's expense. In addition, the Company has no obligation to store or recover any value of the removed attachments.

Q. WHY WOULD THE COMPANY TERMINATE AN OPERATOR'S RIGHT OF ATTACHMENT?

A. The Company may terminate an operator's right of attachment if it fails to pay any of the charges, fees, or amounts provided in Tariff C.A.T.V., substantially defaults under its obligation under the tariff, or repeatedly defaults under those obligations. Operators are provided 30 days to cure any default or non-compliance prior to termination.

<u>Temporary Service (Tariff T.S.) (Sheet 21-1)</u>

Q. WHAT CHANGES ARE BEING MADE TO THE COMPANY'S TEMPORARY SERVICE TARIFF?

A. The Company is proposing the following changes to its Temporary Service tariff:

- Temporary service will be made available only upon demonstration the service will be temporary in nature;
- Limiting the temporary service period to 180 days from the installation of the service with possible extensions for additional 90-day periods upon the customer demonstrating a need for an extension; and
- Requiring the payment of a minimum temporary service installation charge to recover the actual cost of installation, connection, disconnection, and removal of the required facilities to provide temporary service.

Q. WHY IS KENTUCKY POWER REQUIRING CUSTOMERS SEEKING TO BE SERVED UNDER TARIFF T.S. TO DEMONSTRATE THAT THE SERVICE WILL BE TEMPORARY?

A. Temporary service is intended for construction and other temporary purposes, not for permanent occupancy or service. It is being abused by some customers who continue to take service under Tariff T.S. even after the construction is complete and the facility is occupied. Temporary service is provided only at 100 amperes and is insufficient to provide service to a full range of electrical loads in a completed structure (i.e. electric heating). Utilizing temporary service for completed projects creates a safety and reliability hazard for the Company and its customers.

Q. ARE THERE OTHER ISSUES WITH CUSTOMERS WHO CONTINUE TO TAKE SERVICE UNDER TARIFF T.S. AFTER THE FACILITY IS PERMANENTLY OCCUPIED?

A. Yes. Some customers continue to take temporary service after the facility is occupied instead of switching to one of the general service tariffs to avoid state and local codes. For example, KRS 211.350(8) prohibits certified electrical inspectors from issuing certificates of approval of electrical wiring prior to receipt of a notice of release from the local health department concerning any onsite sewage disposal systems. Customers wishing to avoid complying with the onsite sewage disposal system regulations sometimes maintain temporary service as a means of doing so.

Q. IS THE COMPANY PROPOSING TO "POLICE" ITS SERVICE TERRITORY THROUGH THIS MODIFICATION?

A. No. The modifications are means through which Kentucky Power can better ensure that customers take service under the appropriate tariff, that temporary service will be limited to temporary installations, and that temporary service is not being used in an unsafe manner or in a manner that could impact reliability.

Q. WHAT IF CONSTRUCTION REQUIRES MORE THAN 180 DAYS?

A. Temporary service may be extended in 90-day increments upon Kentucky Power's determination of a need for the extension.

Q. WHY HAS THE COMPANY ADDED LANGUAGE REGARDING THE MINIMUM TEMPORARY SERVICE CHARGE TO TARIFF T.S.?

A. The modification clarifies that customers seeking temporary service will be required to pay a charge, in advance, that compensates the Company for the actual costs associated with the temporary installation.

System Sales Clause (Tariff S.S.C.) (Sheet 19-1 through Sheet 19-2)

Q. IS THE COMPANY PROPOSING TO MODIFY ITS SYSTEM SALES CLAUSE TARIFF?

A. Yes. The Company is proposing to modify Tariff S.S.C to switch from a monthly system sales adjustment factor to an annual factor and to update the annual base system sales margin amount. Details regarding the proposed changes to Tariff S.S.C are included in the testimony of Company Witness Vaughan.

Non-Utility Generator (Tariff N.U.G.) (Sheet 26-1 through 26-3)

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO THE COMPANY'S NON-UTILITY GENERATOR TARIFF.

A. The Company is proposing to eliminate outdated language in its tariff that states a 30-day written notice is provided to customers taking service under this tariff should a Transmission Provider implement charges for transmission congestion. In addition, the Company is proposing language under the tariffs special terms and conditions to clarify the requirement to take service for remote self-supply. Additional information regarding the need for these changes is included in the testimony of Company Witness Vaughan.

Environmental Surcharge (Tariff E.S.) (Sheet 29-1 through Sheet 29-7)

Q. IS THE COMPANY PROPOSING TO MODIFY ITS ENVIRONMENTAL SURCHARGE TARIFF?

A. Yes. The Company is proposing to modify Tariff E.S. to incorporate revisions to its environmental compliance plan and to update its monthly base environmental costs. Additional information regarding the proposed changes to Tariff E.S. are included in the testimony of Company Witness Elliott.

Green Pricing Option Rider (Rider G.P.O.) (Sheet 31-1 through Sheet 31-2)

Q. IS KENTUCKY POWER PROPOSING TO CHANGE ITS GREEN PRICING OPTION RIDER?

A. Yes. The Company is proposing to amend its Green Pricing Option Rider to expand the categories of renewable energy credits available and to allow participating customers to purchase their full requirements from renewable energy generators. In addition, the Company is proposing to change the name of the Green Pricing Option Rider to the Renewable Power Option Rider (R.P.O.). Additional information regarding the nature of and need for the revisions are included in testimonies of Company Witnesses Hall and Vaughan.

Purchase Power Adjustment (Tariff P.P.A.) (Sheet 35-1 through Sheet 35-3)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO TARIFF P.P.A.

A. The Company is proposing the following with regards to Tariff P.P.A.:

- Change from a monthly purchase power adjustment factor to an annual factor;
- Redesign the rate structure to a structure similar to the Company's Big Sandy Unit 1 Operations Rider (B.S.1.O.R.);
- Include a base level related to net PJM Open Access Transmission Tariff (OATT) charges and credits that the Company incurs from its participation as a load serving entity (LSE) in PJM, where any differences between the base level and actual expenses will be recovered through the operation of Tariff P.P.A.;
- Include a base level of expenses related to purchase power costs excluded from recovery via the F.A.C., where any differences between the base level and actual expenses will be recovered through the operation of Tariff P.P.A.; and
- Include a base level of net gains and losses on incremental sales of natural gas purchased for Big Sandy Unit 1 where any differences between the base level and actual net gains and losses will be recovered through the operation of Tariff P.P.A..

Additional information regarding the changes to Tariff P.P.A. is included in the testimony of Company Witness Vaughan.

<u>Big Sandy Retirement Rider (Rider B.S.R.R.) (Sheet 38-1 through Sheet 38-2)</u>

Q. WHAT CHANGE IS KENTUCKY POWER PROPOSING FOR THE BIG SANDY RETIREMENT RIDER?

A. Kentucky Power is proposing to change the name of the Big Sandy Retirement Rider to the Decommissioning Rider.

Q. WHY IS THE COMPANY CHANGING THE NAME OF THE BIG SANDY RETIREMENT RIDER?

A. Based on feedback the Company has received from customers, there appears to be some confusion regarding the purpose of the rider, including that the Big Sandy Retirement Rider is used to fund retirement expenses for former Big Sandy employees. This is not the case. The Big Sandy Retirement Rider was approved in the Company's last rate case, Case No. 2014-00396, to recover the costs associated with the decommissioning of Big Sandy Unit 2 and the coal-related retirement costs of Big Sandy Unit 1. Recovery of these costs through a separate rider was first approved in Case No. 2012-00578. Changing the name of the rider to the Decommissioning Rider will alleviate any confusion regarding the purpose of the rider.

Q. WILL THERE BE ANY CHANGES TO THE OPERATION OF THE BIG SANDY RETIREMENT RIDER AS A RESULT OF THIS CHANGE?

A. No. The only change proposed is the name of the rider. The rider will continue to operate in the manner approved by the Commission in Case No. 2014-00396.

Changes Applicable to All General Rate Tariffs

Q. IS KENTUCKY MODIFYING THE MANNER IN WHICH INFORMATION CONCERNING THE SURCHARGES, RIDERS, AND OTHER CHARGES APPLICABLE TO EACH GENERAL RATE TARIFF IS PRESENTED?

A. Yes. Currently, summary descriptions of the applicable surcharges, riders, and other charges are provided on each general rate tariff. Kentucky Power is proposing to remove the summary descriptions and instead include in each service class tariff sheet a cross-reference to the separate "stand-alone" tariff sheets for each surcharge, rider, and other charge applicable to the general tariff. The use of the cross-references will make the general tariff more compact, and hence more easily usable, while providing those customers desiring more information about applicable riders, surcharges, and other charges a convenient means of obtaining it.

V. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.

A. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the following adjustments:

Adjustment	Exhibit 2, Page No.
Interest Expense on Customer Deposits	W16
Postage Rate Decrease Adjustment	W20
Elimination of Advertising Expense	W21
Elimination of Non-Recoverable Business Expense	W40
CATV Revenue Adjustment	W46
Annualization of PSC Maintenance Fee Assessment	W47

Interest Expense Associated with Customer Deposits (Section V, Exhibit 2, W16)

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR INTEREST EXPENSE ASSOCIATED WITH CUSTOMER DEPOSITS.

A. During the test year, the interest rate paid by Kentucky Power pursuant to KRS 278.460 on deposits was 0.37%. The test year deposit interest expense was $110,400. On December 2, 2016 the Commission announced that the 2017 interest rate applicable to deposits would be increased to 0.66%. Consistent with the treatment of deposit interest expense in prior rate cases, Kentucky Power proposes to increase the test year deposit interest expense by $67,254 to $177,655 to reflect the increase in the applicable rate from 0.37% to 0.66%.

Postage Rate Decrease Adjustment
(Section V, Exhibit 2, W20)

Q. WHY IS A POSTAGE RATE DECREASE ADJUSTMENT NECESSARY?

A. The test year adjustment for postage expense is necessary to annualize the United States Postal Service's decrease in the first ounce postage rate for metered mail. The adjustment accounts for a decrease in postage rates which occurred on January 22, 2017. To reflect these going forward decreased costs, the Company reduced the test year postage costs incurred between March 1, 2016 and January 21, 2017 to reflect the lower postage rate. As a result of this adjustment, the Company reduced its test year postage rate expense by $6,656.

Eliminate Advertising Expense
(Section V, Exhibit 2, W21)

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ELIMINATE ADVERTISING EXPENSE.

A. Pursuant to 807 KAR 5:016 Section 4(1), advertising expenditures for political, promotional, and institutional advertising by electric or gas utilities are disallowed for rate-making purposes. Following a review of the Company's advertising expenses recorded during the test year, a total of $100,444 is being eliminated from test year operating expenses.

Eliminate Non-Recoverable Business Expenses
(Section V, Exhibit 2, W40)

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ELIMINATE NON-RECOVERABLE BUSINESS EXPENSES.

A. The Company is removing non-recoverable business expenses during the test year, including those relating to memberships, athletic events tickets, employee gifts and awards. The adjustment decreases the Company's test year expenses by $14,914.

CATV Revenue Adjustment
(Section V, Exhibit 2, W46)

Q. PLEASE EXPLAIN THE CATV REVENUE ADJUSTMENT.

A. As described above, the Company is proposing to increase pole attachment rates for cable television operators under Tariff C.A.T.V. The Company has adjusted test year revenues by $532,369 to reflect the Company's proposed increase in pole attachment rates.

Annualization of PSC Assessment
(Section V, Exhibit 2, W47)

Q. WHY IS THE COMPANY ANNUALIZING ITS COMMISSION MAINTENANCE FEE ASSESSMENT EXPENSE?

A. The Company received an invoice from the Commonwealth of Kentucky on June 8, 2016 in the amount of $1,126,799 for the Kentucky PSC assessment. During the test year, the Company recorded $1,129,500 in Kentucky PSC assessment. The Company's proposed adjustment to test year expenses reflects the difference between the test year amount and the 2016 assessment, or $1,801.

VI. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

KENTUCKY POWER
PO Box 24410
Canton, OH 44701-4410

Amount due on or before February 1, 2017 **$776.03**

Your billing date is Jan 14, 2017
Account #XXX-XXX-XXX-X-X

SERVICE ADDRESS: KPCO RESIDENTIAL CUSTOMER, 123 ANYWHERE CT, ANYWHERE, KY 12345-1234 CY 11

3085-1
030003085 01 AV 0.373

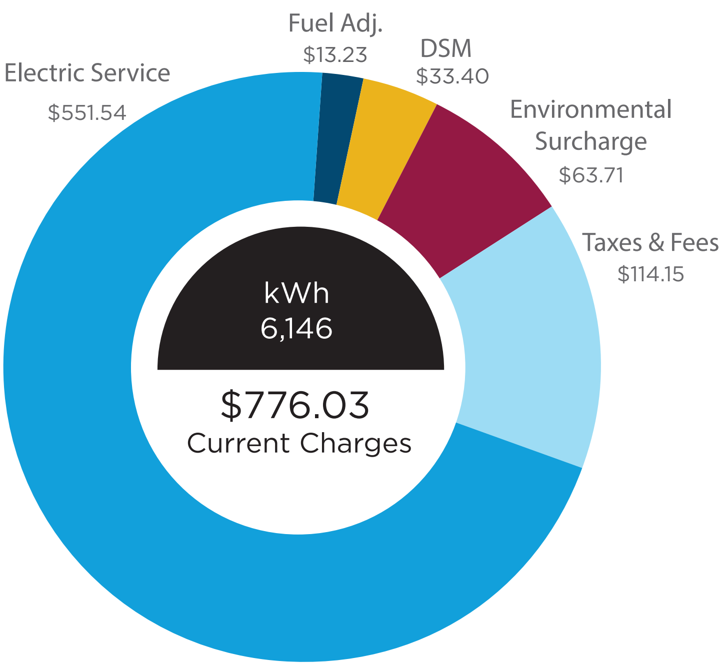
KPCO RESIDENTIAL CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Notes from Kentucky Power:

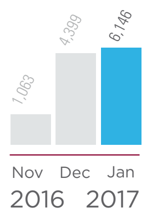
Make this the last bill sent in the mail. Gain more security and trust and Go Paperless to get an email notification when your bill is ready. Today is the Day! AEPPaperless.com

Current bill summary:

Service from 12/12/16 – 01/13/17 (32 DAYS)



Usage history (kWh):



Methods of payment:

kentuckypower.com

PO Box 24410
Canton, OH 44701-4410

1-800-611-0964 ($2.95 fee)

Need to get in touch?

Customer Operations Center: 1-800-572-1113

There's more information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KPCO RESIDENTIAL CUSTOMER, 123 ANYWHERE CT, ANYWHERE, KY 12345-1234

77603
Account #XXX-XXX-XXX-X-X

KENTUCKY POWER

Send inquiries to:
PO Box 24410
Canton, OH 44701-4710

Amount due on or before February 1, 2017 **$776.03**

Payment amount: $

Pay $814.83 After 02/01/17

Make check payable and send to:

American Electric Power
PO Box 24410
Canton, OH 44701-4410

00001356100001362101000000000004100392169201123120189000008

KENTUCKY POWER

Service Address:

3085-02

KPCO RESIDENTIAL CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Account #XXX-XXX-XXX-X-X

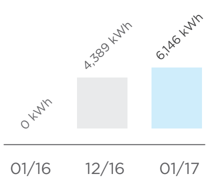
Line Item Charges:

Previous Charges		
Total Amount due at last billing	$	371.15
Payment 12/21/16 - Thank you		-371.15
Previous Balance Due	**$**	**0**
Current KPCO Charges		
Tariff 015 - Residential Service 01/13/17		
Rate Billing	$	551.54
Fuel Adj @ 0.0021534 Per kWh		13.23
DSM Adj @ 0.0054343 Per kWh		33.40
Environmental Surcharge 9.9045000%		63.71
School Tax		21.94
Franchise Fee		22.60
State Sales Tax		69.61
Current Balance Due	**$**	**776.03**
Total Balance Due	**$**	**776.03**

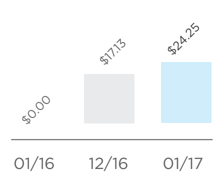
Usage Details:

↑↓ Values reflect changes between current month and previous month.

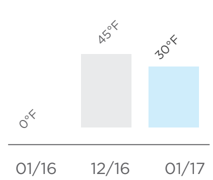
Usage:
↑5,618 kWh



Avg. Daily Cost:
↑$7.12



Avg. Temperature:
↓15°F



Total usage for the past 12 months: 5,472 kWh
Your average monthly usage: 2,736 kWh

Meter Details:

Meter #123456789					
Prev.	Type	Current	Type	Metered	Usage
91461	Actual	97607	Actual	6,146	6,146 kWh
Service Period 12/12 - 01/13				Multiplier 1.00000	
Next scheduled read date should be between Feb 13 and Feb 16.					

Notes from Kentucky Power:

Make this the last bill sent in the mail. Gain more security and trust and Go Paperless to get an email notification when your bill is ready. Today is the Day! AEPPaperless.com.

Worried that changes in the postal service may delay your bill or your payment? Go paperless! You'll receive an email notification when your new bill is available for viewing. You'll also be able to pay online for free. Go to AEPPaperless.com to enroll today!

Visit us at kentuckypower.com

Rates available on request

Paying by check authorizes us to send the information from your check electronically to your bank for payment. If your check is processed electronically, the transaction will appear on your bank statement, although your physical check will not be presented to your financial institution or returned to you. The original check will be destroyed after it is processed. This transaction will not enroll you in any automatic debit process and will only occur each time a check is received. Any re-submissions due to insufficient funds may also occur electronically. Please be aware that all checking transactions will remain secure in this check conversion program. If you have questions about this process or do not want your check to be converted, please contact our Customer Operations Center at the number printed on your bill.

KENTUCKY POWER COMPANY

KENTUCKY POWER
PO Box 24410
Canton, OH 44701-4410

Amount due on or before April 17, 2017 **$106.31**

Your billing date is Mar 31, 2017
Account #123-456-789-0-1

SERVICE ADDRESS: KPCO GENERAL SERVICE CUSTOMER, 123 ANYWHERE CT, ANYWHERE, KY 12345-1234 CY 11

3085-1
030003085 01 AV 0.373

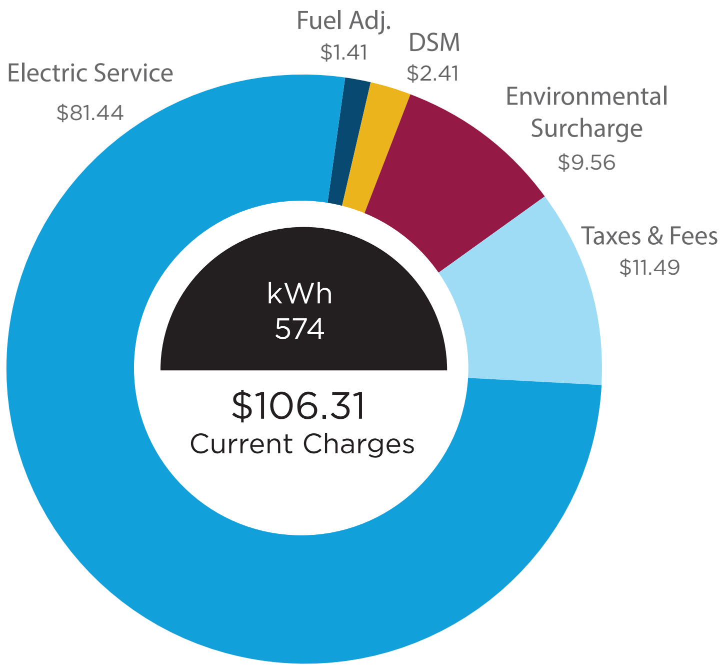
KPCO GENERAL SERVICE CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Notes from Kentucky Power:

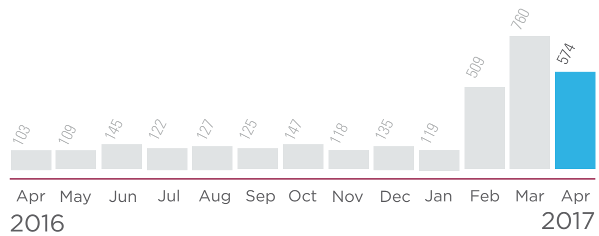
Make this the last bill sent in the mail. Gain more security and trust and go paperless to get an email notification when your bill is ready. Today is the day! AEPPaperless.com

Current bill summary:

Service from 03/01/17 - 03/30/17 (30 days)



Usage history (kWh):



Methods of payment:

kentuckypower.com

PO Box 24410
Canton, OH 44701-4410

1-800-611-0964 ($2.95 fee)

Need to get in touch?

Customer Operations Center: 1-800-572-1113

There's more information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KPCO GENERAL SERVICE CUSTOMER, 123 ANYWHERE CT, ANYWHERE, KY 12345-1234

77603

Account #123-456-789-0-1

KENTUCKY POWER
Send inquiries to:
PO Box 24410
Canton, OH 44701-4710

Amount due on or before April 17, 2017 **$106.31**

Payment amount: $

Pay $111.63 After 04/17/17

Make check payable and send to:

American Electric Power
PO Box 24410
Canton, OH 44701-4410

0000135610000136210100000000000410039216920112312018900008

KENTUCKY POWER

Service Address:

3085-2

KPCO GENERAL SERVICE CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Account #123-456-789-0-1

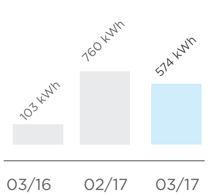
Line Item Charges:

Previous Charges		
Total Amount due at last billing	$	124.15
Payment 03/14/17 - Thank You		-124.15
Previous Balance Due	**$**	**0**
Current KPCO Charges		
Tariff 215 - General Service 03/30/17		
Rate Billing	$	81.44
Fuel Adj @ 0.0024696 Per kWh		1.41
DSM Adj @ 0.0042060 Per kWh		2.41
Environmental Surcharge 13.1119000%		9.71
School Tax		4.81
Franchise Fee		2.56
State Sales Tax		3.97
Current Balance Due	**$**	**106.31**
Total Balance Due	**$**	**106.31**

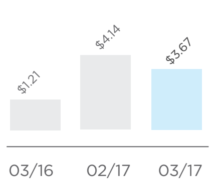
Usage Details:

↑↓ Values reflect changes between current month and previous month.

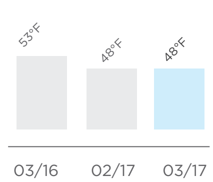
Usage:
↓186 kWh



Avg. Daily Cost:
↓$0.47



Avg. Temperature:
↓0°F



Total usage for the past 12 months: 2,519 kWh
Your average monthly usage: 210 kWh

Meter Details:

Meter #123456789					
Prev.	Type	Current	Type	Metered	Usage
33192	Actual	33766	Actual	574	574 kWh
Service Period 03/01 - 03/30				Multiplier 1.00000	
Next scheduled read date should be between Apr 27 and May 2.					

Notes from Kentucky Power:

Make this the last bill sent in the mail. Gain more security and trust and Go Paperless to get an email notification when your bill is ready. Today is the Day! AEPPaperless.com.

Stealing copper is illegal and can have deadly consequences. **Reporting copper theft** could save a life, so if you have any information, **please call 1-866-747-5845**

KENTUCKY POWER
PO Box 24410
Canton, OH 44701-4410

Amount due on or before February 20, 2017 **$4,669.15**

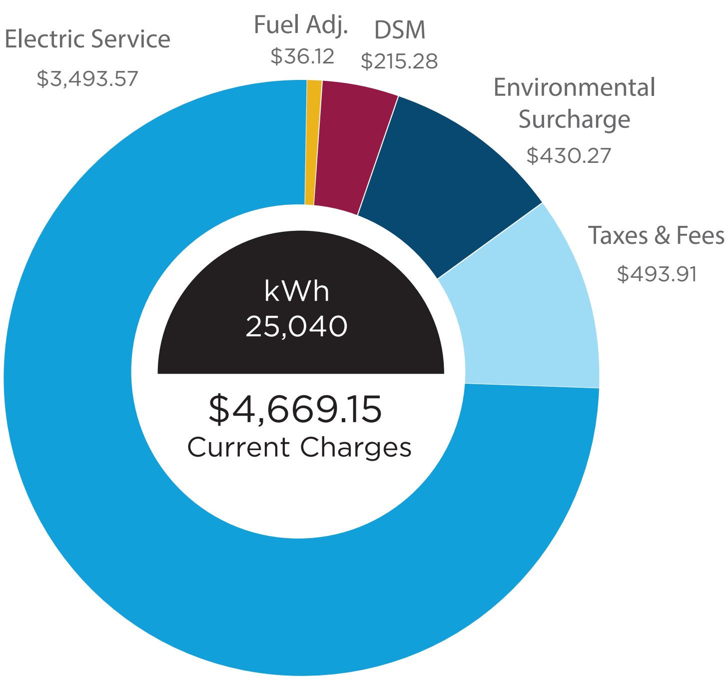
Your billing date is Feb 2, 2017
Account #123-456-789-0-1

SERVICE ADDRESS: KPCO LARGE GENERAL SERVICE CUSTOMER, 123 ANYWHERE CT, ANYWHERE, KY 12345-1234 CY 03

2435-2
KPCO LARGE GENERAL SERVICE CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Current bill summary:

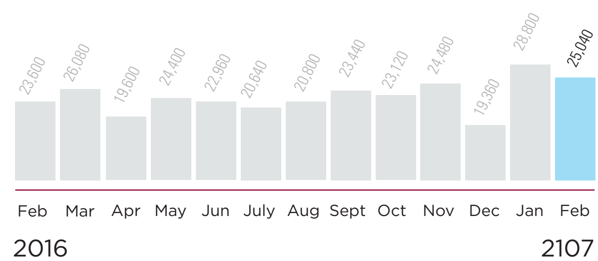
Service from 01/03/17 - 02/01/17 (28 days)



Notes from Kentucky Power:

Make this the last bill sent in the mail. Gain more security and trust and Go Paperless to get an email notification when your bill is ready. Today is the Day! AEPPaperless.com

Usage history (kWh):



Methods of payment:

kentuckypower.com
PO Box 24410
Canton, OH 44701-4410
1-800-611-0964 ($2.95 fee)

Need to get in touch?

Customer Operations Center: 1-800-572-1113

There's more information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KPCO LARGE GENERAL SERVICE CUSTOMER, 123 ANYWHERE CT, ANYWHERE, KY 12345-1234

466915
Account #123-456-789-0-1

KENTUCKY POWER
Send inquiries to:
PO Box 24410
Canton, OH 44701-4710

Amount due on or before February 20, 2017 **$4,669.15**

Payment amount: $

$4,902.61 After 02/20/17

Make check payable and send to:

American Electric Power
PO Box 24410
Canton, OH 44701-4410

0000135610000136210100000000000041003921692011231201890000 8

KENTUCKY POWER

Service Address:

2435-2

KPCO LARGE GENERAL SERVICE CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Account #123-456-789-0-1

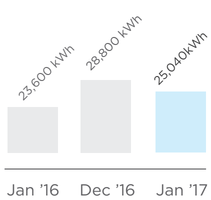
Line Item Charges:

Previous Charges		
Total Amount due at last billing	$	5,203.34
Payment 01/16/17 - Thank You		-5,203.34
Previous Balance Due	**$**	**0**
Current KPCO Charges		
Tariff 240 - Large General Service 02/01/17		
Rate Billing	$	3554.98
Fuel Adj @ 0.0021534 Per kWh		53.92
DSM Adj @ 0.0054343 Per kWh		136.07
Environmental Surcharge 9.9045000%		430.27
School Tax		124.40
Franchise Fee		105.22
State Sales Tax		264.29
Current Balance Due	**$**	**4,669.15**
Total Balance Due	**$**	**4,669.15**

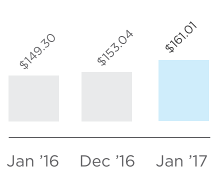
Usage Details:

↑↓ Values reflect changes between current month and previous month.

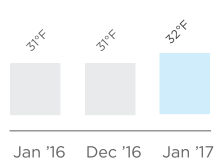
Usage History:
↓3,760 kWh



Avg. Daily Cost:
↑$7.97



Avg. Temperature:
↑1°F



Total kWh for the past 12 months is 279,360
Your Average Monthly Usage: 23,280 kWh

Billed Usage 02/17				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
	(60.9)	(1.1676)		
25,040	-	-	-	25,040 kWh
221.600	-	-	-	221.600 kWh
32,640	-	-	-	32,640 kvarh

Meter Details:

Meter #123456789					
Prev.	Type	Current	Type	Metered	Usage
97,294	Actual	97607	Actual	25,040	25,040 kWh
-	Actual	-	Actual	221.600	221.600 kW
5474	Actual	5882	Actual	32,640	32,640 kvarh
Service Period 01/03 - 02/01				Multiplier 80.00000	
Next scheduled read date should be between Mar 2 and Mar 7.					

Notes from Kentucky Power:

Visit us at kentuckypower.com

Rates available on request

KENTUCKY POWER CALCULATION OF CATV ATTACHMENT FEE 12ME Dec 31 2016					
Line	**Description**	**FERC Acct. Ref.**	**Report Reference or Formula**	**Amount**	**Line**
1	**Gross Investment**				1
2	Poles	364	FORM 1; Page 207 (g)Ln64	200,051,477	2
3	Conductor	365	FORM 1; Page 207 (g)Ln65	217,777,641	3
4	Services	369	FORM 1; Page 207 (g)Ln69	59,716,180	4
5	Total Overhead Accts		Sum Accts 364,365,369 (L2+L3+L4)	477,545,298	5
6	Total Dist. Plant		FORM 1; Page 207 (g)Ln75	782,655,295	6
7	Total Utility Plant		FORM 1; Page 200 (b)Ln8	2,595,462,093	7
8					8
9	**Deprec. Reserve**				9
10	Poles		(L2/L6)*L12	57,943,222	10
11	Overhead Accts		(L5/L6)*L12	138,316,967	11
12	Total Dist. Plant		FORM 1; Page 219 (c)Ln26	226,689,503	12
13	Total Utility Plant		FORM 1; Page 200 (b)Ln14	855,212,999	13
14					14
15	**Deferred Taxes**				15
16	Poles		(L2-L10)/(L7-L13)*L24	40,588,537	16
17	Overhead Accts		(L5-L11)/(L7-L13)*L24	96,889,386	17
18					18
19	**Total Utility Plant**				19
20	For Accel. Amort. Ppty	281	FORM 1; Page 273 (k)Ln8	58,282,271	20
21	For Other Ppty	282	FORM 1; Page 275 (k)Ln2	340,485,495	21
22	Deferred FIT-Other	283	FORM 1; Page 277 (k)Ln9	123,374,858	22
23	Deferred Taxes	190	FORM 1; Page 234 (c)Ln8	25,097,857	23
24	Deferred Taxes Tot. Plt.		Sum Accts 281,282,283 Less 190 (L20+L21+L22-L23)	497,044,767	24
25					25
26	Net Pole Investment		L2-L10-L16	101,519,718	26
27	Net Overhead Accts		L5-L11-L17	242,338,945	27
28	Net Plant Investment		L7-L13-L24	1,243,204,327	28
29					29
30	Appurt. Elimination Rate		Per Administrative Case No. 251	15.00%	30
31	Major Appurt Elimination Rate		Per 2006 Rate Case Settlement	32.24%	31
32	Number of Poles		Company Records as of 12/31/16	215,838	32
33	Net Cost of a Bare Pole		(L26*(1-L31)*(1-L30))/L32	270.90	33
34					34
35	Deprec. Rate - Poles		Annual Deprec. Rate (Exhibit 11; Final Order Case No. 2014-00396)	3.52%	35
36	Administrative Exp.		FORM 1; Page 323 (b)Ln 197	21,710,706	36
37	Pole Maintenance Exp		L26/L27*L38	16,550,591	37
38	Mainten. of Overhead Lines	593	FORM 1; Page 322 (b)Ln 149	39,508,115	38
39					39
40	**Operating Taxes**				40
41	Taxes Other Than Income	408	FORM 1; Page 114 (c)Ln 14	21,299,832	41
42	Income Taxes - Federal	409.1a	FORM 1; Page 114 (c)Ln 15	5,704,182	42
43	Income Taxes - Other	409.1b	FORM 1; Page 114 (c)Ln 16	96,461	43
44	Provision for Def. Inc. Tax	410.1	FORM 1; Page 114 (c)Ln 17	115,546,545	44
45	Provision for Def. Inc. Tax (cr.)	411.1	FORM 1; Page 114 (c)Ln 18	-95,774,242	45
46	Investment Tax Cr. Adj. - Net	411.4	FORM 1; Page 114 (c)Ln 19	-2,630	46
47	Operating Taxes - Total		L41+L42+L43+L44+L45+L46	46,870,148	47
48					48
49	Depreciation Expense Factor		(L35*L2)/L26	6.94%	49
50	Admin. Factor		L36/L28	1.75%	50
51	Pole Mainten. Factor		L37/L26	16.30%	51
52	Tax Expense Factor		L47/L28	3.77%	52
53	Rate of Return		Final Order Case No. 2014-00396	7.34%	53
54	Annual Cost Factor		L49+L50+L51+L52+L53	36.10%	54
55	Annual Net Pole Cost		L33*L54	$97.79	55
56					56
57	**Two User**				57
58	CATV Co. Space %		Per Administrative Case No. 251	12.24%	58
59	***Proposed CATV Co. Attachment Fee***		**L55*L58**	**$11.97**	59
60	Current Rate			$7.21	60
61					61
62	**Three User**				62
63	CATV Co. Space %		Per Administrative Case No. 251	7.59%	63
64	***Proposed CATV Co. Attachment Fee***		**L55*L63**	**$7.42**	64
65	Current Rate			$4.47	65

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Manager, Regulatory Pricing and Analysis that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Alex E. Vaughan

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, this the 20th day of June 2017.

Amanda E Owen

Notary Public

Notary ID Number :

My Commission Expires: Never

NOTARIAL SEAL STATE OF OHIO

Amanda E. Owen, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

DIRECT TESTIMONY OF
ALEX E. VAUGHAN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
ALEX E. VAUGHAN
FOR KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2017-00179

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Alex E. Vaughan, and I am employed by American Electric Power Service Corporation ("AEPSC") as Manager, Regulated Pricing and Analysis. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include the oversight of cost of service analyses, rate design, and special contracts for the AEP East System operating companies.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEP, I worked for a retail bank and a holding company where I held various underwriting, finance and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the Regional Transmission Organization ("RTO") Settlements Group. I later became the PJM Settlements Lead Analyst where I was responsible for reconciling AEP's settlement of its activities in the PJM market with the monthly PJM invoices and for resolving billing issues with PJM. In 2010, I transferred to

Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's 11 state jurisdictions and at the Federal Energy Regulatory Commission ("FERC"). In addition, I was responsible for performing financial analyses related to AEP's generation resources and loads, power pools and PJM. In September of 2012, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I presented testimony on behalf of the AEP Operating Companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee and Indiana. In Kentucky, I have testified before the Kentucky Public Service Commission (the "Commission") in Case No. 2013-00197 and Case No. 2014-00396 on behalf of the Company. I have also participated in and provided information to the Commission in several informal conferences.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is four-fold:

(1) to provide an overview of how the Company's base rates relate to the various surcharges and riders it utilizes;

(2) to describe the Company's proposed rate design, including the changes to the residential service charge and the proposal to combine the small general service tariff and the medium general service tariff;

(3) to describe certain changes to the Company's tariffs, including (a) changes to the Purchase Power Adjustment (PPA) tariff, the System Sales Clause tariff, and the optional Green Pricing Option Rider; (b) the elimination of the Pilot Tariff K-12 Schools (Public School tariff); and (c) the Company's new, voluntary Pilot Residential Demand-Meter Electric Service tariff; and

(4) to support certain operation and maintenance expense and operating revenue adjustments detailed in Section V, Exhibit 2, including adjustments related to

(a) base purchased power expense; (b) adjustments to the test year amount of PJM charges and credits; (c) adjustments to the test year level of Off System Sales (OSS) margins; and (d) adjustments to the test year firm sales revenues.

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

- Exhibit AEV 1 – Base Rate Revenue Target Summary
- Exhibit AEV 2 – Full Cost Basic Service Charge Calculation
- Exhibit AEV 3 – Marginal Customer Connection Study
- Exhibit AEV 4 – Relative Class Rates of Return
- Exhibit AEV 5 – Proposed Revisions to Green Pricing Option Rider (Renewable Power Option)
- Exhibit AEV 6 – New Residential Demand Tariff
- Exhibit AEV 7 – Proposed PPA Tariff
- Exhibit AEV 8 – Proposed Peaking Unit Equivalent Cost Calculation

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

III. BASE RATE COST OF SERVICE OVERVIEW

Q. CAN YOU DESCRIBE GENERALLY THE MECHANISMS THROUGH WHICH KENTUCKY POWER CHARGES ITS CUSTOMERS FOR THE ELECTRIC SERVICE IT PROVIDES?

A. Yes. Kentucky Power charges its customers for electric service through two types of mechanisms: (1) base rates and (2) surcharges and riders. Through base rates, the Company recovers its operating expenses and a return on and of the capital investments it has prudently made to provide safe and reliable electric service to its customers. The

Company also recovers through surcharges and riders certain operating expenses and returns on investments that are volatile or otherwise inappropriate for recovery through base rates.

Q. HOW DOES THE INTERRELATION BETWEEN BASE RATES AND THE COMPANY'S SURCHARGES AFFECT THE COST OF SERVICE STUDY PERFORMED IN THIS CASE?

A. Kentucky Power's test year revenues and operating expenses included revenues and expenses relating to the following surcharges and riders:

- Big Sandy 1 Operations Rider ("BS1OR")
- Big Sandy Retirement Rider
- Environmental Surcharge
- Purchase Power Adjustment
- DSM Adjustment Clause
- Fuel Adjustment Clause
- System Sales Clause
- Capacity Charge
- Home Energy Assistance Program ("HEAP") Surcharge
- Kentucky Economic Development Surcharge ("KEDS")

To properly determine the portion of the cost of service to be recovered through base rates, the Company had to address the revenues and expenses associated with each of these surcharges. How each of these surcharges is addressed depends on the manner in which those surcharges operate.

Q. ARE THERE ANY SURCHARGES FOR WHICH THE ASSOCIATED REVENUES AND EXPENSES ARE FULLY REMOVED FROM BASE RATES?

A. Yes. The Company removed all revenues and expenses associated with the following surcharges from base rates:

- Big Sandy Retirement Rider (Decommissioning Rider)
- DSM Adjustment Clause
- Capacity Charge
- HEAP Surcharge
- Kentucky Economic Development Surcharge

Each of these surcharges recovered specifically identified costs that are separate from the Company's base rates requirements:

- Big Sandy Retirement Rider – through the Big Sandy Retirement Rider, renamed the Decommissioning Rider, the Company recovers the remaining net book value of the retired Big Sandy Unit 2 and the incurred decommissioning costs for coal-related assets at the Big Sandy plant.

- DSM Adjustment Clause – through the DSM Adjustment Clause, the Company recovers the program costs and lost revenues associated with the Company's demand side management and energy efficiency programs.

- Capacity Charge – through the Capacity Charge, the Company recovers $6.2 million annually as approved by the Commission's final order in Case No. 2004-00420 regarding the extension of the Rockport plant unit power service agreement. The Commission's Order specifically requires the Company to remove these revenues from the cost of service.

- HEAP Surcharge – the HEAP surcharge is a fixed charge levied on each residential account, and matched on a dollar-for-dollar basis by the Company, to provide financial assistance to low-income residential customers.

- Kentucky Economic Development Surcharge – Similar to the HEAP surcharge, the KEDS is a fixed charge levied on each account, and matched on a dollar-for-dollar basis by the Company, to support economic development in the Company's service territory.

Q. CONVERSELY, ARE THERE ANY SURCHARGES FOR WHICH THE ASSOCIATED REVENUES AND EXPENSES ARE INCLUDED IN BASE RATES?

A. Yes. For the reasons described below, the Company included the revenues and expenses associated with the following surcharges in base rates:

- Big Sandy 1 Operations Rider
- Environmental Surcharge (non-FGD portion)
- Purchase Power Adjustment
- System Sales Clause.

Q. WHY WERE THE BS1OR REVENUES AND EXPENSES INCLUDED IN BASE RATES?

A. The BS1OR was an interim surcharge, approved by the Commission in Case No. 2014-00396, through which the Company recovered the non-fuel costs associated Big Sandy Unit 1 and a return on and of the capital investment to convert the unit to natural gas. The Company has completed the conversion and is proposing to recover the costs that had been recovered through the BS1OR through base rates. Accordingly, the BS1OR related revenues and expenses have been rolled into the base rate cost of service.

Q. WHY WERE A PORTION OF THE ENVIRONMENTAL SURCHARGE REVENUES INCLUDED IN BASE RATES?

A. The Company incurred costs during the test year associated with projects included in the Company's approved environmental compliance plan. Through the environmental surcharge, the Company recovers from or credits to customers the costs for its environmental projects that exceed or are below the corresponding monthly amounts included in base rates. The Company's test year non-FGD environmental compliance costs and non-FGD environmental surcharge revenues are included in base rates and serve as the monthly baselines against which actual costs are compared.

Q. ARE ALL OF THE TEST YEAR ENVIRONMENTAL COMPLIANCE COSTS INCLUDED IN BASE RATES?

A. No. In accordance with a settlement agreement approved in Case No. 2012-00578, the Company recovers the costs associated with the flue gas desulfurization ("FGD") project at the Mitchell Plant exclusively through the environmental surcharge (as opposed to just the variance from the prior year's costs). Further detail regarding the treatment of the Mitchell FGD is included in the testimony of Company Witness Elliott.

Q. WHY DOES THE COMPANY INCLUDE REVENUE FROM THE SYSTEM SALES CLAUSE IN BASE RATES?

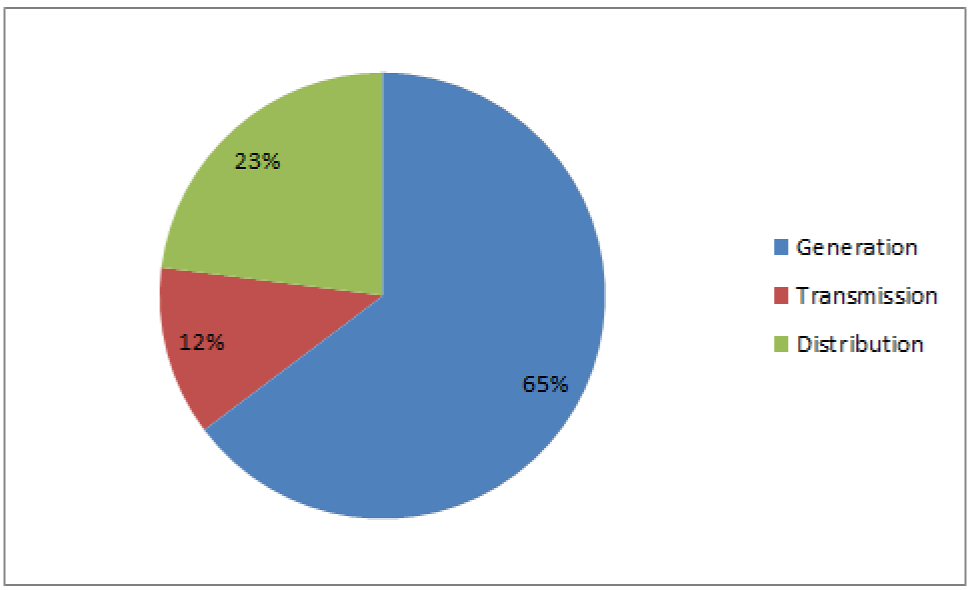
A. Through the system sales clause, the Company shares with customers the difference between the embedded base rate credit for off system sales margins and the actual off system sales margins realized. The Company included the test year level of off system sales margins in the base rate cost of service because the Company is proposing to reset the embedded base rate credit to the test year level of off system sales margins. I will discuss the impact of this reset in more detail later in my testimony.

Q. HAS THE COMPANY SYNCHRONIZED ANY SURCHARGE RELATED REVENUES AND EXPENSES IN BASE RATES?

A. Yes. The Company synchronized the revenues and expenses associated with the Purchase Power Adjustment and the Fuel Adjustment Clause and included both in the base rate cost of service. Synchronization was necessary due to the two month lag between when the expenses are incurred and when they are recovered through the surcharges. Following the synchronization, the test year amounts for these surcharges have no effect on the Company's base rate cost of service. Details regarding the synchronization of the revenues and expenses associated with these surcharges is included in the testimony of Company Witness Rogness. Additionally, the Company has included adjusted baseline amounts in the base rate cost of service related to the Purchase Power Adjustment.

Q. PLEASE PROVIDE A BRIEF SUMMARY REGARDING THE COMPONENTS OF THE COMPANY'S BASE RATE COST OF SERVICE AND GENERALLY WHICH CUSTOMERS ARE RESPONSIBLE FOR THOSE COSTS.

A. The Company's Kentucky retail jurisdictional cost of service breaks down to the basic functions of generation, transmission and distribution service as follows:



The generation function comprises the majority of customers' cost of service. Both the generation function and transmission functions are utilized by all customers and included in all customers' rates. Unlike generation and transmission costs, distribution costs are only included in the rates of distribution voltage level customers, except for a small amount related to metering and billing. Approximately 37% of the Company's adjusted test year usage was for customers taking service at voltage levels above distribution.

Therefore, roughly a quarter of the Company's cost of service is paid by distribution level customers that make up less than two thirds of adjusted test usage.

IV. RATE DESIGN

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE COMPANY'S PROPOSED RATES.

A. The Company's underlying approach in designing rates is to design its rates and rate components so that they reflect the Company's costs to provide service to each of its customer classes. This approach includes collecting basic service-related costs through basic service charges and recognizing the differences in the costs to serve customers at different service delivery voltages.

The rate design process involved multiple steps that varied with each tariff. The cost components developed by Company Witness Buck in the class cost of service study informed the relative amounts of revenue that should be recovered from service charges, energy charges and demand charges. In general, where sufficient metering data was available for a customer class, the Company designed full-cost service charges, energy rates, and demand rates by dividing the component-allocated proposed revenues by the test year billing units. These initial rates were then compared to the current rates to determine whether the Company needed to moderate the full-cost price changes to mitigate rate impacts on groups of customers.

Q. FOR WHICH TARIFFS IS THE COMPANY PROPOSING BASE RATE DESIGN CHANGES IN THIS PROCEEDING?

A. The Company is refining the rate design for residential customers, creating a new optional pilot residential demand metering tariff, and is proposing to combine small and medium general service customers into a newly designed rate structure under a new general service tariff.

i. <u>Residential Service Rate Design</u>

Q. WHAT CHANGES TO THE RESIDENTIAL SERVICE RATE DESIGN IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing to increase the basic service charge to $17.50 per month from $11.

Q. WHAT IS THE RATIONALE FOR INCREASING THE RESIDENTIAL BASIC SERVICE CHARGE?

A. The Company is proposing to increase the basic service charge for residential customers to more accurately reflect the actual fixed cost of providing service to those customers. The rate structures for customer classes that utilize demand charges are better aligned with cost causation principles than those that do not because fixed costs are generally recovered through a demand charge. Because the residential class does not include a separate demand charge, the majority of fixed distribution costs are recovered through the energy charge. These fixed distribution costs, or at least a larger portion of them, should be recovered in the basic service charge since they do not vary with usage and are instead solely the costs associated with connecting a customer to the distribution system and maintaining that connection. The current basic service charge is too low relative to the fixed cost of providing electric service creating intra-class subsidies between customers. Because of these intra-class subsidies, the current basic service charge disadvantages higher usage customers, including electric heating customers.

The following example demonstrates the intra-class subsidies using three hypothetical Kentucky residential customers. These three customers live next door to each other on the same street. All three customers' homes were connected to the Company's distribution system using the same equipment for the same cost. Assuming that these customers' electric rates are structured in the same fashion as the Company's current residential rate design in that the rates include a basic service charge of $11 with the balance of the distribution revenue requirement being recovered through a charge per kWh, the intra-class subsidies are as follows:

	Customer 1	Customer 2	Customer 3	Total
Household Description	Family Using Electric Heating	Single person	Retired couple, spend 5 months of the year in vacation home	
Avg Monthly Usage (kWh)	2,200	1,000	400	3,600
Annual Avg Usage (kWh)	26,400	12,000	4,800	43,200
Annual Fixed Dist Connection Cost	$ 480	$ 480	$ 480	$ 1,440
Annual Basic Service Charge ($11*12)	$ 132	$ 132	$ 132	$ 396
Per kWh charge ($/kWh) = ($1,440-$396)/43,200	0.0242	0.0242	0.0242	
Annual Example Bill for Fixed Distribution Costs =$132 + (annual kWh* 0.0242)	$ 770	$ 422	$ 248	$ 1,440
Subsidy Received/(Paid)	$ (290)	$ 58	$ 232	$ -

In this example, Customer 1 is providing an intra-rate class subsidy to Customers 2 and 3. This is true even though costs incurred by the Company to connect each of the customers to the distribution system are the same for each customer. In other words, Customer 1 is paying too high a share of the fixed cost associated with connecting the three hypothetical customers to the Company's distribution system.

These subsidies between like customers are exactly what the Company's proposed increase to the basic service charge is intended to reduce. Here is the same table with the Company's proposed basic service charge of $17.50:

	Customer 1	Customer 2	Customer 3	Total
Household Description	Family Using Electric Heating	Single person	Retired couple, spend 5 months of the year in vacation home	
Avg Monthly Usage (kWh)	2,200	1,000	400	3,600
Annual Avg Usage (kWh)	26,400	12,000	4,800	43,200
Annual Fixed Dist Connection Cost	$ 480	$ 480	$ 480	$ 1,440
Annual Basic Service Charge ($17.5*12)	$ 210	$ 210	$ 210	$ 630
Per kWh charge ($/kWh) = ($1,440-$630)/43,200	0.0188	0.0188	0.0188	
Annual Example Bill for Fixed Distribution Costs =$210+ (annual kWh* 0.0188)	$ 705	$ 435	$ 300	$ 1,440
Subsidy Received/(Paid)	$ (225)	$ 45	$ 180	$ -

Proposed Subsidy Reduction (paid)/received	$ (65)	$ 13	$ 52	$ -

As can be seen, the Company's proposal reduces the intra-class subsidies as it narrows the gap between the service charge and the actual cost to provide each customer with distribution service.

Q. HOW WILL THE INCREASED BASIC SERVICE CHARGE IMPACT MONTHLY BILL VOLATILITY?

A. Because less of the fixed distribution system connection costs will be recovered through the usage-related energy charge, the average customer will see less volatility in bills in high usage months. This is especially true for the Company's electric heating customers who tend to experience very high usage months in the winter to heat their homes. This proposed rate design change will lessen the bill impact in those months because the increased usage will not result in even greater subsidization of lower usage customers. Further, as described above, this is an appropriate result based upon cost causation principles.

Q. WHAT IMPACT WOULD THE HIGHER BASIC SERVICE CHARGE HAVE ON LOWER INCOME AND ELECTRIC HEATING CUSTOMERS?

A. A higher basic service charge will help lower income customers who, because they often do not have the resources to invest in weatherization and energy efficient appliances, have higher than average usage. Based on test year data, the average kWh usage for the Company's low income energy assistance customers (1,392 kWh/month) is greater than the average usage for the residential class as a whole (1,246 kWh/month). Because the increased service charge benefits higher usage customers by reducing intra-class subsidies, the change will benefit the average low income customer.

The Company's electric heating customers will also benefit from the increased service charge because their average usage (1,483 kWh/month) is also above the residential class average. During the test year, 71% of the Company's low income energy assistance customers were also electric heating customers.

Q. HOW WAS THE NEW BASIC SERVICE CHARGE DETERMINED?

A. The Company calculated the full-cost basic service charge to be approximately $38 per month. The $38 per unit cost represents the cost of the fixed portion of the distribution system used to serve the residential class. Said another way, this is the full cost of the portion of the distribution system that is required just to connect customers to the grid and stand ready to serve them. It does not include costs that vary by kW demand or kWh usage. It should also be noted that the $38 per month full cost basic service charge is a distribution only figure; it does not include any generation or transmission service costs.

While cost causation principles would support a $38 per month basic service charge, the Company is acting consistently with the principle of gradualism and only proposing to raise the basic service charge to $17.50 in this proceeding

Q. HOW DID YOU CALCULATE THE FULL COST BASIC SERVICE CHARGE OF $38?

A. I calculated the full-cost basic service charge by first determining the fixed cost portion of the Company's distribution system attributable to the residential class. Next, I divided this value by the adjusted test year number of residential customer bills to arrive at the approximately $38[1] full-cost basic service charge. This calculation is described in Exhibit AEV 2.

In order to determine the fixed cost portion of the Company's distribution system attributable to the residential class, I utilized the residential class distribution and customer revenue requirements produced by the class cost of service study and used in rate design as the starting point. The customer portion of the revenue requirement was assigned entirely to the full-cost basic service charge calculation because these costs are fixed and only vary with the number of customers taking service. A portion of the remaining distribution revenue requirements was then allocated to the full cost basic service charge revenue requirement using fixed distribution plant allocation factors.

These fixed distribution plant allocation factors originate from a study that examines actual components of the Kentucky Power's distribution system and compares their component costs by distribution plant account classification to what the total cost

[1] $37.88 per customer per month

would be if all components of these distribution plant components were the typical or average size installed by the Company when connecting the average distribution level customer. All component costs up to the typical level are classified as fixed costs that only vary with the number of customers connected to the distribution system. The costs above the typical level are classified as related to demand since the additional cost of these facilities was incurred due to the need to install additional facilities to meet customer kilowatt (kW) demands.

The total of the residential class fixed distribution and customer revenue requirements are then divided by the total number of residential bills in the test year, which produced the approximately $38 per month cost.

Q. DID YOU EXPLORE ANY OTHER METHODS OF PRICING THE FULL COST BASIC SERVICE CHARGE?

A. Yes, I also calculated what the full cost basic service charge would be using what I refer to as "the marginal customer connection" method. The study is included as Exhibit AEV-3. This study identifies the Company's current average marginal cost to connect a residential customer to its distribution system. The total cost of the residential connection is then multiplied by the appropriate levelized carrying charge and divided by 12 to compute the monthly full cost basic service charge.

Using this method, I calculated the full cost basic service charge for a Kentucky Power residential customer to be approximately $39 per month. In other words, the fixed monthly cost associated with connecting the next customer to the distribution system is $39. It should be noted that this is only the cost of connecting the customer to the distribution grid; the $39 per month contains no generation costs, transmission costs or costs of maintaining the connection or existing distribution facilities.

Q. WILL THE COMPANY'S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE DETER ENERGY CONSERVATION?

A. No. In addition to its proposal to increase the basic service charge, the Company has also proposed to increase its base rate kWh charge. Because the amount charged in a customer's bill is still largely driven by the amount of kWh consumed, the increase in basic service charge is not providing customers a price signal that would encourage additional consumption. An increase in usage will still result in an increased bill.

Ideally, the Company would recover little to none of the residential class distribution revenue requirement through a per kWh charge because the distribution revenue requirement does not vary with the amount of kWh consumed. Instead, the Company would institute a per kW demand charge for residential customers to collect residential distribution costs not recovered through the service charge. However, the Company's current residential class metering infrastructure does not provide the information necessary to institute a per kW demand charge for all customers.

Using a per kW demand charge to recover the remaining residential distribution system costs would be preferred because the fixed costs of the distribution system are incurred in two ways. First, costs are incurred by simply connecting a customer to the radial distribution system. These connection costs do not vary with the kWh consumed or the kW demands of customers. The Company is proposing to include a larger portion of these connection costs through the increased basic service charge. Second, the Company incurs residential system distribution costs by sizing the distribution system to meet customer peak kW demand. These sizing costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. These sizing costs would ideally be collected through a demand charge, but this cannot be done for all customers due to the current limitations of the Company's metering infrastructure. In fact, under the Company's proposal, nearly 90% of the Company's residential customer revenues are still being recovered through a per kWh usage charge.

In the absence of a peak demand charge, the Company is proposing to move a portion of those fixed distribution costs that only vary with the number of customers connected to the system from the per kWh charge to the basic service charge.

Q. IS SENDING THE CORRECT PRICE SIGNALS TO CUSTOMERS THROUGH RATES THAT REFLECT THE TRUE COST OF SERVICE IMPORTANT TO THE LONG TERM SUCCESS OF CONSERVATION EFFORTS?

A. Yes. While in the short term a higher kWh charge that does not reflect the true cost of service could encourage conservation, in the long term it provides confusion to customers and can result in customers making uneconomic decisions. Customers expect that when they use less energy, the usage-related portion of their bills will decrease. However, to the extent that the usage-related portion of rates are designed to include a portion of the fixed costs as well, it is likely that as those fixed cost collections diminish the Company will need to increase the usage-related portion of rates. When that happens, customers will see the usage-related portion of their bills increase even though they have conserved energy. It is important to send accurate, cost-based price signals to customers, which is exactly what the Company's proposed residential rate design takes a step towards.

Q. ARE THERE OTHER COST OF SERVICE JUSTIFICATIONS FOR THE COMPANY TO REQUIRE A HIGHER RESIDENTIAL SERVICE CHARGE THAN THE OTHER KENTUCKY INVESTOR OWNED UTILITIES?

A. Yes, for two reasons. First, the Company finds itself in a unique position compared to the other investor owned utilities in Kentucky in regards to the overall density of its service territory. As can be seen in the following table[2], the Company has many fewer customers per distribution line (circuit) mile than does its peers:

IOU	Distribution Circuit Miles	Customers	Customers/Line Mile
Kentucky Power	10,080	168,107	17
Duke Kentucky	2,933	138,605	47
LGE/KU	22,887	928,000	41

As a result, the Company must make more distribution plant investments and incur more maintenance costs per customer to provide service. Second, the topography of the Company's service territory adds to the cost. Kentucky Power's service territory is primarily mountainous creating challenges for distribution system installation and maintenance that other utilities in the Commonwealth do not experience to the same degree. The combination of lower customer density and challenging topography results in a comparatively higher cost based basic service charge.

ii. <u>Optional Residential Demand Charge Tariff</u>

Q. PLEASE DESCRIBE THE OPTIONAL RESIDENTIAL DEMAND RATE TARIFF THE COMPANY IS PROPOSING.

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[2] IOU information sources: filed 10-K forms, FERC Form 1, and KY PSC Annual Gross Operating Revenue Reports.

A. The Company is proposing a new optional residential rate schedule, called Residential Demand-Metered Electric Service ("Tariff RSD"). This optional tariff is available to up to 1,000 residential customers and utilizes a three-part rate structure with a monthly service charge, on-peak and off-peak kWh energy charges, and an on-peak kW demand charge. The on-peak period is limited to 7:00 AM – 11:00 AM in the months of October through May and 4:00 PM – 9:00 PM during the months of June through September. The on-peak periods coincide with the Company's winter heating peak hours and summer cooling peak hours. The goal of this optional rate structure is to send targeted price signals that will reward customers for shifting usage away from the peak time periods that cause the Company to incur higher costs. Additionally, it is possible that some electric heating customers could benefit under this rate structure due to their potentially higher load factor usage characteristics.

Q. PLEASE EXPLAIN HOW THE COMPANY DESIGNED THE TARIFF RSD RATES.

A. The rates for Tariff RSD were calculated by first determining what the demand charge should be in light of the proposed $17.50 basic service charge. To calculate the demand charge, I first calculated the service charge revenue that the proposed $17.50 basic service charge would produce across the entire residential class by multiplying the service charge by the total number of residential billing units. The basic service charge revenue was then subtracted from the total customer and distribution secondary and primary revenue targets and divided by the residential class total kW demands to produce the $4.44/kW on-peak demand charge.

I next determined the off-peak energy charge by adding one cent per kWh to the average off-peak energy rate calculated in the residential storage water heating rate design producing a rate of 7.418 cents per kWh. I chose to add a cent to the off-peak residential rate because the off peak period for Tariff RSD is larger than off-peak period in the standard residential tariff. Accordingly, it is appropriate to recover more fixed costs under the off-peak Tariff RSD rate because there will be fewer on-peak kWh billing units under Tariff RSD.

The on-peak energy charge of 13.747 cents per kWh is a residual calculation that collects the remainder of the revenue target not included in the service charge, on-peak demand charge or off-peak energy rate.

The Tariff RSD rate design is revenue neutral to the standard residential tariff. This means that if all residential customers were able to and did switch to the proposed Tariff RSD and did not change their usage patterns, there would be no difference in the amount of revenue produced as compared to the revenue that would have been produced under the standard residential tariff. The proposed Tariff RSD is attached to my testimony as Exhibit AEV 6.

iii. <u>Small General Service & Medium General Service Rate Design</u>

Q. IS THE COMPANY PROPOSING A RATE DESIGN CHANGE TO THE SGS AND MGS TARIFFS?

A. Yes, the Company is proposing to combine the two existing tariffs into a single "General Service" (GS) tariff under which all general service customers with average demands up to 100 kW will take service.

Q. WHY IS THE COMPANY PROPOSING TO COMBINE THE SGS AND MGS TARIFFS?

A. The Company is creating the new GS tariff for tariff administration efficiencies. During the test year, 3,793 customer accounts moved between the SGS and MGS tariffs.[3] This occurred because some customers' load characteristics vary such that the best tariff for them in some months is the SGS tariff and in other months the best tariff is the MGS tariff. The Company's proposed GS tariff is designed to eliminate these transition issues by effectively billing customers each month using the rate design in the current SGS or MGS tariffs that is most beneficial to them.

Q. PLEASE BRIEFLY DESCRIBE THE NEW GS TARIFF RATE DESIGN.

A. The new GS tariff is designed to combine rate design features from the current SGS and MGS tariffs. The current SGS tariff includes a kWh blocked energy charge[4] and a monthly service charge. The current MGS tariff, on the other hand, includes an hours use blocked energy charge[5], a per kW demand charge, and a monthly service charge. Current MGS customers have meters capable of recording monthly kW demand readings while SGS customers do not. The new GS tariff rate design includes a monthly service charge, a blocked energy charge, and a demand charge for monthly billing demand greater than 10kW. This structure is designed to minimize bill impacts on current SGS and MGS customers while ensuring that they receive service under the most favorable terms based on usage.

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[3] 1,245 SGS customers moved from SGS to MGS, and 2,548 MGS customers moved to SGS.
[4] The SGS tariff has 2 kWh blocks, the first 500 kWh each month and all kWh over 500.
[5] The MGS tariff has two blocks of billing energy, block 1 is equal to 200 kwh per kW of demand, the second block is all remaining kWh.

The new GS tariff blocked energy charge establishes one rate for monthly usage less than or equal to 4,450 kWh and another rate for all monthly usage in excess of 4,450 kWh. The transition point for the blocked energy charge is based on the average SGS class load factor multiplied by 10kW – the maximum demand level for receiving service under the current SGS tariff. Setting the kWh block rate in this manner ensures that almost all usage that would have been billed under the current SGS tariff will continue to be billed on an energy charge only. It also provides a clear delineation for customers who will require a demand meter because when their usage exceeds the block breaking point their metered demand is most likely at or above 10 kW.

V. TARIFF CHANGES AND NEW OFFERINGS

i. Public School Service Tariff

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS CASE REGARDING THE PILOT PUBLIC SCHOOL TARIFF THAT WAS ESTABLISHED IN CASE NO. 2014-00396?

A. The Company is proposing to discontinue the pilot Public School Service tariff because the Company's load research and class cost of service study shows that the Public School Service customers would be better off in the Large General Service (LGS) class. This is due to the load characteristics of customers taking service under the Public School Service tariff. The public school load research data was not available at the time of the Company's last base rate case when this pilot tariff was created as part of the settlement agreement.

Q. DID THE COMPANY COMPLY WITH ITS COMMITMENTS UNDER THE SETTLEMENT AGREEMENT IN CASE NO. 2014-00396 REGARDING THE PUBLIC SCHOOL TARIFF?

A. Yes. As required by Paragraph 16 of the settlement agreement in Case No. 2014-00396, the Company established a pilot K-12 Public School Service tariff with rates designed to produce a lower annual revenue requirement than would be produced under the LGS tariff. The Company added 30 load research meters to K-12 Public School Service tariff accounts to provide the load information necessary for further analysis.

Q. WAS CONTINUATION OF THE DISCOUNTED PUBLIC SCHOOLS TARIFF JUSTIFIED BY THE CLASS COST OF SERVICE STUDY?

A. No. To test whether there was a cost of service justification for a separate, discounted public schools tariff, the Company evaluated public school tariff customers as a separate customer class in the class cost of service study utilizing the results obtained from the load research meters. The results of the class cost of service study for the separate public schools tariff class were then compared to the standard LGS tariff class. The public schools class produced a lower return on rate base than did the LGS class (6.17% vs 8.29% respectively) as shown in Exhibit AEV-4. This indicates that the public school usage characteristics do not support the current lower prices that they pay relative to the LGS class that they were previously a part of.

As a result of their lower return and to reflect the true cost of service for the class, the public school class was allocated a higher percentage of the revenue increase when calculating the class revenue targets for rate design purposes. This discrepancy between the public schools tariff customers and the LGS customers is generally attributable to the fact that public school tariff customers have lower average load factors than standard LGS customers. Said another way, rather than justifying a discounted rate for the public school tariff customers, the class cost of service study shows that the public school tariff customers actually benefit from the load diversity and higher average load factor of the standard LGS customers when they were on the LGS rate schedules.

Because there is not a cost of service justification for the lower rate under the pilot Public Schools Service tariff, the Company is proposing to discontinue the pilot tariff, and to return the Public School Service customers to taking service under the LGS tariff.

ii. <u>Renewable Power Option Rider</u>

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE CURRENT GREEN PRICING OPTION RIDER.

A. Besides changing the name of the tariff to the "Renewable Power Option" Rider, the Company is proposing to expand the renewable options available to customers. The Company's current Green Pricing Option Rider offers a single renewable energy certificate (REC) purchase option that could be sourced from any renewable resource. The new Renewable Power Option Rider provides three specific REC purchase options:

1. Solar RECs
2. Wind RECs
3. Hydroelectric and Other RECs

Each REC purchase option is priced according to the approximate cost of procuring the RECs on behalf of customers. All RECs purchased under this tariff will be retained or retired by the Company on behalf of customers. By retaining or retiring the RECs for the customers, the Company is ensuring that RECs are removed from circulation and cannot be bought or sold again in the REC markets. All of the costs associated with service under the Renewable Power Option Rider are borne solely by the customers who select to receive service under the rider. Because this is an optional service, there is no cost of service impact on customers who do not participate in the Renewable Power Option Rider.

Also included in proposed tariff RPO is an option for larger customers to contract with the Company bilaterally to directly purchase the electrical output and all associated environmental attributes from a specific renewable energy project. The proposed Renewable Power Option Rider is attached to my testimony as Exhibit AEV 5.

iii. **<u>Non Utility Generator Tariff Changes</u>**

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE NON UTILITY GENERATOR ("NUG")TARIFF.

A. The NUG tariff has been updated to remove an antiquated clause regarding potential future transmission congestion charges. The tariff contemplated how existing customers would be notified if a regional transmission organization created such charges. Since there are no customers currently on the NUG tariff, and PJM has already created transmission congestion charges, the notice language relating to the creation of these charges is no longer necessary. The Company also made clarifying edits regarding the provision of station power to the special terms and conditions section.

iv. **<u>Proposed Changes to the Purchase Power Adjustment Rider</u>**

Q. WHAT COST OF SERVICE ITEMS ARE CURRENTLY APPROVED FOR INCLUSION IN THE PURCHASE POWER ADJUSTMENT RIDER?

A. The Company's Purchase Power Adjustment Rider ("Tariff PPA") currently authorizes the Company to recover through the monthly Purchase Power Adjustment factor the cost of (1) demand credits paid to CS-IRP customers for their commitment to interrupt service during PJM-initiated demand response events, (2) certain purchase power expenses that are not recoverable through the Company's fuel adjustment clause ("FAC"), and (3) the cost of power purchased by the Company through new Purchase Power Agreements.

Q. WHAT ADDITIONAL COST OF SERVICE ITEMS IS THE COMPANY PROPOSING TO INCLUDE IN THE PURCHASE POWER ADJUSTMENT RIDER?

A. The Company is proposing to include the following additional cost of service items to be tracked and recovered through Tariff PPA: (1) various PJM Open Access Transmission Tariff ("OATT") charges and credits that it incurs or receives from its participation as a load serving entity ("LSE") in the organized wholesale power markets of the PJM RTO, (2) purchase power costs excluded from recovery though the FAC as a result of the purchased power limitation ("FAC Purchased Power Limitation"), and (3) gains and losses from incidental gas sales.

(a). <u>PJM LSE OATT Charges and Credits</u>

Q. WHAT SPECIFIC PJM CHARGE AND CREDIT ITEMS IS THE COMPANY PROPOSING TO INCLUDE IN TARIFF PPA?

A. Kentucky Power incurs charges and credits as an LSE and transmission owner in PJM under the FERC-approved OATT. The Company is proposing to include the following PJM LSE transmission charges and credits to the costs recoverable through Tariff PPA: network integration transmission service (NITS), transmission owner scheduling system control and dispatch service (TO), regional transmission expansion plan (RTEP), point-to-point (PTP) transmission service, and RTO start-up cost recovery. Together these charges represent the cost of wholesale transmission service from PJM for the Company's load.

Q. IS THE COMPANY PROPOSING TO REMOVE THESE PJM OATT CHARGES AND CREDITS FROM BASE RATES ENTIRELY?

A. No. The Company is proposing to include an adjusted test year level of the net OATT charges and credits in base rates. The Company would then, on a monthly basis, track the amount of net OATT LSE charges and credits above or below the base rate level using deferral accounting. The annual net over or under collection of PJM charges, as compared to the annual amount included in base rates, would then be collected from or credited to customers through the operation of Tariff PPA.

Q. WHY IS THE COMPANY PROPOSING A TRACKING MECHANISM FOR THESE PJM OATT LSE CHARGES AND CREDITS?

A. These PJM charges and credits are volatile and can have a significant financial impact on the Company. The annual level of such charges and credits can vary greatly from year to year and are largely out of the Company's control.

Q. ARE THERE ANY ADDITIONAL REASONS FOR INCLUDING THE PJM OATT LSE CHARGES AND CREDITS IN A TRACKING MECHANISM?

A. Yes. The Company expects increasing investment in the transmission grid by PJM member transmission owners. This investment, which is necessary to maintain and improve the grid, will increase transmission charges allocated to LSEs in PJM, including Kentucky Power. Tracking these PJM LSE charges and credits via Tariff PPA could potentially avoid the cost and administrative inefficiencies arising from more frequent rate cases that could otherwise be necessary as these PJM OATT LSE charges change. Also, there are two pending FERC proceedings that may affect the level of PJM LSE OATT charges incurred by the Company.

First, a challenge to the return on equity included in the AEP Zone formula rate, which determines the PJM transmission cost of service for the AEP Transmission Zone, has been lodged via a FERC 206 filing in docket EL17-13. Although FERC may act on the merits of this challenge at any time after a quorum of FERC commissioners is established, the Company does not expect FERC to issue an order on the merits lowering the return on equity prior to the Company's new base rates going into effect in January 2018. Additionally, any new resulting return on equity applicable for the AEP Zone Transmission cost of service for the AEP companies is not known or measurable at this time, and the Company, therefore, cannot include an adjustment in this base rate case to account for the possible ROE change.

Second, there is a pending non-unanimous settlement before FERC in docket number EL05-121 regarding the cost allocation methodology historically used by PJM to allocate the costs of transmission enhancement projects to the LSEs in PJM's footprint. If approved by FERC without modification, the proposed stipulation is expected to result in lower PJM LSE OATT charges for customers; although the timing or magnitude of the possible cost allocation changes are not currently known.

The uncertainty surrounding the two FERC proceedings that may affect the Company's going level of PJM LSE OATT charges and credits illustrates the volatility of these costs and highlights the need to track the difference between the amount in base rates for these items and the actual costs incurred. This difference can be tracked effectively through the Company's Tariff PPA. If these FERC proceedings result in a reduction in the PJM LSE OATT charges for Kentucky Power's customers, the proposed tracking mechanism would allow the Company to flow those reductions to its customers in short order. If this tracking mechanism is approved, the Company would recover from customers only the actual amount of cost incurred for wholesale transmission service, not a dollar less or more.

Q. WHAT IS THE PROPOSED LEVEL OF PJM LSE OATT CHARGES AND CREDITS TO BE INCLUDED IN BASE RATES?

A. The adjusted test year Kentucky retail jurisdictional total of net PJM LSE OATT charges and credits included in base rates is $74,377,364. This amount has grown from $53,779,456 in Case No. 2014-00396.

(b) FAC Purchased Power Limitations

Q. WHAT OTHER CHANGES TO THE PURCHASE POWER ADJUSTMENT RIDER IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing to include a level of expense in its base rates related to the FAC Purchased Power Limitation that is generally driven by the peaking unit equivalent calculation and the forced outage purchase power limitation. The Company would then, on a monthly basis, track the amount of purchase power costs excluded from recovery through the FAC above or below the base rate level using deferral accounting. The annual net over or under collection of these FAC-excluded purchase power costs, as compared to the annual amount included in base rates, would then be collected from or credited to customers through the operation of Tariff PPA.

Q. PLEASE DESCRIBE THE FAC PURCHASED POWER LIMITATION AND WHY THE DIFFERENCES BETWEEN ACTUAL FAC PURCHASED POWER LIMITATION EXPENSE AND THE AMOUNT EMBEDDED IN BASE RATES SHOULD BE TRACKED THROUGH THE PURCHASE POWER ADJUSTMENT RIDER?

A. The FAC Purchase Power Limitation is a calculation that caps the amount of purchase power expense to be recovered in the Company's monthly FAC surcharge. The calculation compares the cost of actual purchased power on an hourly basis[6] to the cost of the Company's highest cost unit or the theoretical peaking unit equivalent and caps the FAC-recoverable purchase power expense at the cost ($/MWh) of the highest cost generating unit (Company owned or peaking unit equivalent). The peaking unit equivalent was created as a proxy because Kentucky Power does not own any peaking units. The FAC Purchase Power Limitation is applied to all[7] purchased power expense used to serve the Company's customers.

The very structure of the FAC Purchase Power Limitation and the peaking unit equivalent calculation promotes variability and volatility because it relies on factors that are outside of the Company's control. Moreover, because the FAC Purchase Power Limitation applies regardless of whether all of the Company's generation resources are being dispatched by PJM in that hour, if some or all resources are on a scheduled maintenance outage, or if it is simply more economic in that hour to purchase PJM spot market energy rather than generate it from Kentucky Power's generating fleet, the

[6] There is a monthly threshold test that is first applied to see if the hourly calculation is necessary.
[7] All purchased power expense excluding that which is characterized as being attributable to generator forced outages which is excluded from FAC recovery separately.

amount of purchased power expense excluded from the FAC is unpredictable and incredibly variable.

The variable nature of the FAC Purchase Power Limitation is shown in the historic period studied[8] by the Company for purposes of Adjustment 26. During that period, the monthly FAC Purchase Power Limitation calculation yielded as little as $19 and as much as $7,172,309 of non-FAC recoverable purchase power expense. That is a 38,272,526% variance over the course of 3 years. This volatility is driven by the commodity market exposure that is inherent in the peaking unit equivalent calculation because the cost of the hypothetical peaking unit equivalent is based on the lowest hourly natural gas price at the Columbia Gas Appalachian pricing point and an arbitrary heat rate compared to the commodity price of the marginal supply resource[9] in PJM's hourly spot energy market. During the period studied the price of energy in PJM's real time spot energy market ranged from a low of -$230/MWh to a high of $1,839/MWh. These extreme price variations coupled with the variability of the Company's hourly generation resource supply vs. load demand position creates a volatile benchmark for capping the amount of purchase power expense that can be included for recovery in the Company's FAC.

This type of unpredictable, volatile, and significant operating expense is the very definition of what should be tracked so that customers do not win or lose on this cost of service; but rather pay only what was incurred by the Company to serve customers, not a dollar more or less.

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[8] January 2014 – February 2017
[9] The marginal resource in PJM is generally a natural gas combustion turbine, but can be any resource in PJM's hourly energy markets.

Q. HAS THE COMPANY PROPOSED THIS TYPE OF RECOVERY IN PREVIOUS PROCEEDINGS FOR THE FAC PURCHASE POWER LIMITATION EXPENSE?

A. Yes, in Case No. 2014-00396, the Company proposed to collect all FAC Purchase Power Limitation expense through Tariff PPA. In its final order in that proceeding the Commission denied this recovery and stated the following:

> *"Kentucky Power has not shown that the amounts of these excluded purchased power costs are volatile to the point of requiring this method of recovery. In addition, the Commission notes that there would be numerous administrative issues involved in establishing periodic proceedings to review and approve or deny these costs. The Commission believes these costs are more appropriately recoverable through base rates and will not approve this portion of the Settlement."*

The Company's proposal in this case conforms to the Commission's guidance on this issue in past cases. The Company's proposal to include an adjusted level of purchase power limitation expense in its base rate cost of service and track the differences between that level and the volatile, actual expense is reasonable and equitable to both customers and the Company. Moreover, this method does not add any significant administrative burden as it is similar to other tracking mechanisms utilized the by the Company. If this expense item is not tracked through the purchase power adjustment, the Company stands to profit from or lose on an item that should be a dollar for dollar pass-through to customers as a cost of serving them, due to the extreme volatility and materiality of the FAC Purchase Power Limitation expense.

Q. IS THE COMPANY PROPOSING ANY CHANGE TO THE CALCULATION OF THE FAC PURCHASED POWER LIMITATION?

A. Yes. The Company is proposing to change the methodology for calculating the cost of the peaking unit equivalent used in the determining the FAC Purchased Power

Limitation. The Company's proposed change results in a peaking unit equivalent cost that more accurately reflects the cost of a hypothetical combustion turbine.

Q. PLEASE DESCRIBE HOW THE COST OF THE PEAKING UNIT EQUIVALENT IS CALCULATED.

A. Currently, the cost of the peaking unit equivalent is calculated solely by multiplying the lowest hourly daily gas price at the Columbia Gas Appalachian pricing point (in $/MMBtu) by a 10,400 heat rate (10,800 for June – August), divided by 1,000). For example, a gas price of $3/MMBtu results in a peaking unit equivalent cost of $31.2/MWh [(3*10,400)/1000 = 31.2]. If the peaking unit equivalent is the highest cost unit in that hour[10], the FAC Purchased Power Limitation limits recovery of purchased power costs through the FAC to $31.2/MWh. To the extent the expense arising from this operation of the FAC Purchased Power Limitation, which is controlled by factors outside the Company's control, is not included in base rates, the Company is forced to absorb the expense.

Q. WHAT CHANGES TO THE PEAKING UNIT EQUIVALENT CALCULATION IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company proposes to include the following operating costs in calculation of the cost of the peaking unit equivalent:

- Unit startup costs
- The cost of firm natural gas service
- Variable O&M expense

[10] The hourly peaking unit equivalent cost calculation compares the hypothetical peaking unit to the Company's other generating units and uses the highest cost unit for the FAC Purchased Power Limitation calculation. The hypothetical peaking unit is often the highest cost unit.

Q. WHY SHOULD THESE COSTS BE INCLUDED IN THE PEAKING UNIT EQUIVALENT COST CALCULATION?

A. All of these costs the Company is proposing to include are costs that would be incurred to operate an actual natural gas combustion turbine generating unit (CT). The peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT because the Company does not own a real CT for the purposes of calculating the FAC Purchased Power Limitation.

CT startup costs include start up fuel consumed, station power requirements and start up maintenance and labor; and are incurred when bringing a CT online but prior to the unit generating power. These are real costs that the hypothetical CT would incur in order to generate electricity and should be included in the peaking unit equivalent cost calculation.

In order to be available to generate electricity, a CT needs to have access to natural gas which is contracted for on either a non-firm or firm basis. Firm gas service means that the unit has reserved a portion of the capacity in the pipeline making gas always available for use in generating electricity. Since the hypothetical CT used in the peaking unit equivalent cost calculation can be “dispatched” any day of the year, it requires firm gas service. Because this is a cost that an actual CT would incur to provide the service presumed for the hypothetical CT, it should be included in the peaking unit equivalent cost calculation.

Finally, Variable O&M expense associated with operating the hypothetical CT should also be included in the peaking unit equivalent cost calculation because these expenses are necessary to generate electricity at a CT.

Q. PLEASE QUANTIFY THE IMPACT ON THE PEAKING UNIT EQUIVALENT COST CALCULATION FROM THESE PROPOSED CHANGES.

A. Based on the Company's experience and information available regarding costs associated with combustion turbines, the startup costs, variable O&M, and firm gas components combine to add between \$38 - \$39/MWh to the peaking unit equivalent cost calculation depending on the month of the year. The details behind this calculation can be found in Exhibit AEV 8.

(c) <u>Gains and Losses from Incidental Gas Sales</u>

Q. WHY IS THE COMPANY ALSO PROPOSING TO TRACK GAINS AND LOSSES FROM INCIDENTAL GAS SALES THROUGH TARIFF PPA?

A. Like PJM LSE OATT charges and credits and FAC Purchased Power Limitation expenses, gains and losses from the incidental sales of natural gas that the Company had purchased for use at Big Sandy Unit 1, but could not use or store, are highly volatile and largely outside of the Company's control. Additional information about the gains and losses from incidental gas sales is included in the testimony of Company Witness Rogness.

Q. IS THE COMPANY PROPOSING ADDITIONAL CHANGES TO TARIFF PPA IN THIS PROCEEDING?

A. Yes. In addition to tracking and recovering the difference between the costs described above, and the amount of those costs included in base rates, the Company is proposing to change the structure of the Power Purchase Adjustment itself from a monthly adjusting surcharge to an annually updated surcharge. The Company also proposes to change the rate structure from a percentage of revenue charge to a structure that includes a per-kWh charge for energy-related costs and a per-kW charge for demand-related costs, for certain demand metered tariffs. These changes to the rider's structure are meant to promote monthly bill stability. Because a base level of expense for the items the Company is proposing to track via Tariff PPA has been included in its proposed base rates, the Company proposes to set the Annual Purchase Power Adjustment's initial rates to zero for the first year. Please see Exhibit AEV 7 for the proposed Tariff PPA rate design and tariff.

Q. IF THE COMMISSION APPROVES THE PROPOSED CHANGES TO THE PURCHASE POWER ADJUSTMENT RIDER, WHEN WOULD THE COMPANY PROPOSE TO UPDATE TARIFF PPA RATES?

A. Tariff PPA is designed to true-up the actual incurred purchase power related costs relative to the amounts in the Company's base rates. As a result, the Annual Purchase Power Adjustment will be set at $0 when the Company's new base rates go into effect. After that, it will be trued-up annually. The Company proposes filing the required true-up information beginning no later than August 15 of each year, with updated rates to be effective cycle 1 of October. The Company will make its first filing of required true-up information by August 15, 2018.

v. <u>Proposed Change to the System Sales Clause</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE SYSTEM SALES CLAUSE TARIFF.

A. The Company is proposing to change the system sales clause tariff ("Tariff SSC") to utilize an annually adjusting rate instead of a monthly adjusting surcharge. Since the test year level of off system sales margins have been included as a credit to the Company's base rate cost of service, now is an opportune time to make such a switch that will help simplify the Company's tariffs and reduce monthly bill volatility. Under the Company's proposal, the initial Tariff SSC rate would be set to $0 and the difference between actual off system sales margins and the base amount of $7,163,948 would be deferred based on the current 75/25[11] sharing calculation that occurs in the monthly SSC accounting. The net deferred credit or charge to customers would then be the basis for the annual SSC rate update. The Company proposes filing the required true-up information beginning no later than August 15 of each year, with updated rates to be effective cycle 1 of October. The Company will make its first filing of required true-up information by August 15, 2018.

VI. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.

A. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the following adjustments:

Adjustment	Exhibit 2, Page No.
Adjust Test Year Off System Sales (OSS) Margins	W8
Adjust Firm Sales for Tariff Migration	W13
Year End Number of Customers Annualization	W14
Adjust Firm Sales for Normal Weather	W15
Include Base Level of Purchase Power Limitation Expense	W26

[11] Currently the Company credits 75% of the difference between base and actual off system sales margins amounts to customers and retains 25%.

Include Base Level of Forced Outage Purchase Power Limitation Expense	W27
Adjust PJM LSE OATT Expense to Going Level	W28
Adjust PJM Admin Fees to Going Level	W29
Surcharge Book to Bill Adjustment	W54

Adjust Test Year Off System Sales (OSS) Margins
(Section V, Exhibit 2, W8)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR OSS MARGINS.

A. The purpose of this adjustment is to include in the base rate cost of service the adjusted test year level of OSS margins. The adjusted test year amount of OSS margins is $7,163,948, and this is the amount that the Company proposes to include as the new base credit that will be tracked through the System Sales Clause.

Q. HOW WAS THIS ADJUSTMENT CALCULATED?

A. To adjust the base rate cost of service so that it only reflects the test year amount of OSS margins, three items must be accounted for:

1. System Sales Clause retail revenues;
2. The portion of the fuel deferral related to the System Sales Clause; and
3. Non-associated utilities (OSS) environmental costs

During the test year, the System Sales Clause collected $5,313,052 from customers because actual OSS margins were less than the amount included in base rates. This $5.3 million of retail revenues were removed from the base rate cost of service as part of Adjustment W8. During the test year, a deferred fuel expense amount of $173,875 relating to the System Sales Clause was recorded on the Company’s books. This amount was reversed as part of this adjustment to remove the test year deferral's effect on the base rate cost of service. Lastly, to adjust the base rate cost of service so that it reflects the proper amount of OSS margins, I took into account the test year amount non-associated companies environmental costs. The test year amount for this item was $3,661,679. These costs are related to the Commission's Orders Dated March 31, 2003 in Case No. 2002-00169 and September 7, 2005 in Case No. 2005-00068, that require the Company to allocate its environmental costs on a percentage of revenue basis to OSS margins. These allocated environmental costs are deducted from actual OSS margins during monthly System Sales Clause accounting to arrive at the amount of actual OSS margins to be shared with customers.

The net effect of these three items in Adjustment W8 is an $8,800,856 increase to the base rate cost of service and re-sets the base rate OSS margin credit level to $7,163,948.

Adjust Firm Sales for Tariff Migration
(Section V, Exhibit 2, W13)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR FIRM SALES REVENUE.

A. The purpose of the tariff migration adjustment is to determine the test year revenue that Kentucky Power would have received if each customer were billed for the entire twelve months of the test year on the tariff under which the customer was taking service at the end of the test year. For example, a customer may have been billed under the MGS (Medium General Service) tariff for the first seven months of the test year and then billed under the LGS (Large General Service) tariff for the remaining five months of the test year.

Q. HOW IS THE TARIFF MIGRATION ADJUSTMENT CALCULATED?

A. The tariff migration adjustment starts with the "per books revenue" as shown in Section II of this filing. "Per books revenue" means the revenues from customers as they were actually billed for each month of the test year. For purposes of the tariff migration adjustment, these customers would be re-billed for the entire test year under the tariff under which they received service at the end of the test year to determine the impact on test year revenues. This restatement of per books revenue was made for each customer who switched tariffs during the test year. This results in an increase of test year revenues of $1,026,263.

Year End Number of Customers Annualization
(Section V, Exhibit 2, W14)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR FIRM SALES REVENUE.

A. The purpose of the year end customer annualization adjustment is to restate test year revenues and expenses to reflect, on an annual basis, changes in load that occurred during the test year. For example, if the number of residential customers increased during the test year, per books residential kWh sales would have to be increased to reflect the impact of annualizing load growth that occurred within the test year. In addition to the revenue adjustment, test year variable operating expenses would also have to be increased or decreased to reflect the incremental costs associated with annualizing test year load growth or decline.

Q. HOW IS THE YEAR END CUSTOMER ANNUALIZATION ADJUSTMENT CALCULATED?

A. The year-end customer annualization adjustment begins with the number of customers in each tariff class at the end of the historic test year and adds or subtracts usage from the test year amounts by the average amount of usage per customer. These adjusted billing units then calculate the new adjusted firm sales revenues for the various tariffs.

To ensure that the customer annualization adjustment reflects only actual customer growth or decline, the impact of customer migrations has been eliminated by starting with the data adjusted for the tariff migration adjustment. Additionally, the year-end customer annualization adjustment includes the elimination or addition of any known specific changes to customer loads.

In addition to the impact on firm sales revenue, the year-end customer annualization adjustment reflects a change in variable operating expense that would also change based on load growth or decline. The year-end customer annualization adjustment reduces firm sales revenues by $3,274,059 and reduces operation and maintenance expense by $1,931,695.

Adjust Firm Sales for Normal Weather
(Section V, Exhibit 2, W15)

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT.

A. The purpose of the Weather Normalization Adjustment is to restate test year revenues and expenses to reflect a 30-year average load for weather sensitive customers compared to the weather experienced during the test year. The Company bases its weather normalization on deviations from normal in both heating and cooling degree-days.

Using data provided by the Company's Economic Forecasting Group, the adjustment was calculated to increase residential energy usage to the level of the 30-year average. The adjustment was limited to the residential customer class because these customers have the highest correlation of energy usage to weather. The result of this adjustment was to increase total usage by approximately 102.7 million kilowatt-hours and increase revenues by $9,953,044. The weather normalization adjustment also reflects the change in variable operating expense that the Company would experience based on this positive adjustment to residential class load. Accordingly, this adjustment increases operation and maintenance expense by $4,080,748.

Include Base Level of FAC Purchased Power Limitation Expense
(Section V, Exhibit 2, W26)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR BASE RATE PURCHASE POWER EXPENSE RELATED TO THE FAC PURCHASED POWER LIMITATION.

A. This adjustment increases the base rate cost of service by $3,150,582 to account for a three year adjusted average of reasonably incurred purchase power expense excluded from recovery through the FAC Purchased Power Limitation. The Commission has previously instructed the Company that purchase power costs not recoverable through the FAC are eligible for recovery through base rates.[12]

Q. WHY DID YOU CHOOSE A THREE YEAR AVERAGE FOR THE PROPOSED BASE LEVEL OF PURCHASED POWER LIMITATION EXPENSE?

A. A three year historic average was chosen to incorporate sufficiently diverse weather, load, generation, and natural gas pricing conditions into the proposed base rate expense adjustment that is driven largely by the peaking unit equivalent cost calculation in the Company's monthly FAC accounting process. All of these factors play an important role

[12] Order, *In the Matter of: An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of American Electric Power Company from May 1, 2001 to October 31, 2011*, Case No. 2000-00495-B, at 5 (Ky. P.S.C., May 2, 2002).

in the results of the FAC Purchased Power Limitation calculations, and many of them are out of the Company’s control and are volatile.

Q. HOW DID YOU CALCULATE THIS ADJUSTMENT?

A. An adjusted three year average amount of FAC Purchased Power Limitation expense was used to calculate the amount of additional purchase power expense to be included in the Company’s base rate cost of service. Because Big Sandy Unit 2 was still operating during 15 months of the historic period from March of 2014 - May of 2015, the historic actuals were adjusted to remove Big Sandy Unit 2 since the Company's exposure to the purchase power limitation was mitigated by Big Sandy Unit 2's historic output that will not be available to the Company going forward. The Company’s historic internal load, generation and purchase information was used to reconstruct the hourly FAC Purchased Power Limitation calculation for the 15 months in question. After removing the historic Big Sandy Unit 2 hourly generation from the Company's supply stack, the Company required more market purchases of energy that would have been subject to the FAC Purchased Power Limitation. The hourly analysis assumes that all new purchases created by the removal of Big Sandy Unit 2's generation were first met by other Kentucky Power generation, then by historic market purchases for internal load, then by historic purchases that had been assigned to OSS, and then, if the Company was still energy deficient in that hour, a new market purchase was created. These new market purchases were priced at PJM's real time system energy price (locational marginal prices without the congestion and loss components). The FAC Purchased Power Limitation calculation was then applied to the new hourly purchases the Company used to meet its internal load obligations.

Beginning with June 2015, I used the actual historic FAC Purchased Power Limitation calculations because Big Sandy Unit 2 was no longer operating. I then divided the total purchase power limitation expense for the three year period by 36 to get the average monthly amount. That annualized total less the test year amount of FAC Purchased Power Limitation expense is equal to the $3,150,582 adjustment to the base rate cost of service. This amount is directly assigned to the Kentucky retail jurisdiction because it is derived using the Company's Kentucky retail load.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE MONTHLY FAC PURCHASED POWER LIMITATION CALCULATION THAT WOULD AFFECT THE AMOUNT OF THIS ADJUSTMENT?

A. Yes. As described above, the Company is proposing a methodology change to the peaking unit equivalent cost calculation that is included within the monthly FAC Purchased Power Limitation calculation. If the Commission were to adopt the proposed changes to the peaking unit equivalent cost calculation, it would reduce Adjustment W26 by $3,287,910 (from $3,150,582 to $-137,328), which would be a net reduction to the revenue requirement in this case of $3,305,565.[13]

Include Base Level of Forced Outage Related Purchase Power Expense
(Section V, Exhibit 2, W27)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR BASE RATE PURCHASE POWER EXPENSE RELATED TO FORCED OUTAGES.

A. This adjustment was made to include a three year average amount of purchase power expense related to Kentucky Power generation forced outages, which is excluded from

[13] The difference between the effect on the adjustment and the revenue requirement is the income tax impact of the change in Adjustment W26 and the gross revenue conversion factor's effect on the new required net electric operating income figure.

the Company's FAC. The calculation of the adjustment was similar to Adjustment W26 in that the three year period includes the period before Big Sandy Unit 2 was retired. The calculation of the three year average accounts for the removal of Big Sandy Unit 2 from the historic actuals to produce a more representative level of expense because the Company does not have Big Sandy Unit 2's generation, or operational risk, going forward.

During the test year, the Company recovered forced outage related purchase power expense through the Purchase Power Adjustment. Accordingly, the test year amount of expense was zeroed out in the base rate cost of service in Adjustment W9 as described in the testimony of Company Witness Rogness. The three year average amount of forced outage related purchase power expense included in the Company's proposed base rate cost of service is now $882,204.

Adjust Test Year PJM LSE OATT Expense to Going Level
(Section V, Exhibit 2, W28)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF PJM LSE OATT EXPENSE.

A. The FERC approved OATT includes rates and billing units that are different in 2017 than they were in 2016. I adjusted test year PJM LSE OATT expense to account for these differences. This adjustment increases the Kentucky retail jurisdiction base rate cost of service by $3,825,858 for a total adjusted test year OATT LSE expense level of $74,377,364.

Adjust PJM Admin Fees to Going Level
(Section V, Exhibit 2, W29)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF PJM ADMINISTRATION FEE EXPENSE.

A. This adjustment accounts for the FERC-approved[14] 7.5% increase in PJM administrative fees from the 2016 level. This adjustment increases the Kentucky retail jurisdiction base rate cost of service by $118,606.

Surcharge Book to Bill Adjustment
(Section V, Exhibit 2, W54)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. This adjustment accounts for the difference between the cost of service adjustments that remove various surcharges from the test year sales revenues and the billing analysis for the same surcharges. This adjustment reduces firm sales revenues by $62,588.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

[14] FERC Docket No. ER17-249-000

KPCo Kentucky Retail Jurisdiction
Base Rate Revenue Target Summary

				Proposed Tariff GS		Proposed Tariff LGS					
		Total			Total	Total	Total	Total			
	From CCOS	**Retail**	**RS**	**SGS**	**MGS**	**LGS**	**PS**	**IGS**	**MW**	**OL**	**SL**
a	Demand	$ 243,752,700	$ 104,206,522	$ 7,659,911	$ 26,839,501	$ 25,449,489	$ 5,743,787	$ 73,756,368	$ 89,543	$ 6,166	$ 1,413
b	Energy	$ 191,926,408	$ 73,064,956	$ 4,651,909	$ 16,114,623	$ 18,516,846	$ 3,932,692	$ 73,610,566	$ 71,333	$ 1,664,370	$ 299,113
c	Dist Primary	$ 72,512,797	$ 42,843,798	$ 3,067,924	$ 10,665,215	$ 9,320,681	$ 2,209,680	$ 4,195,444	$ 36,121	$ 143,067	$ 30,867
d	Dist Secondary	$ 32,012,721	$ 21,213,526	$ 1,636,335	$ 4,559,449	$ 2,944,372	$ 985,794	$ 69,612	$ 12,829	$ 507,729	$ 83,075
e	Customer	$ 25,589,466	$ 12,249,602	$ 3,465,334	$ 1,188,363	$ 468,678	$ 61,338	$ 256,346	$ 1,530	$ 6,791,546	$ 1,106,729
f= sum a-e	TOTAL	$ 565,794,092	$ 253,578,404	$ 20,481,413	$ 59,367,151	$ 56,700,066	$ 12,933,291	$ 151,888,336	$ 211,356	$ 9,112,878	$ 1,521,197
	Adjustments										
g	Less Fuel Clause	$ 9,129,743	$ 3,264,810	$ 211,604	$ 735,733	$ 832,252	$ 178,342	$ 3,821,769	$ 3,184	$ 68,807	$ 13,242
	Base Rate Revenue Targets										
h=a	Demand	$ 243,752,700	$ 104,206,522	$ 7,659,911	$ 26,839,501	$ 25,449,489	$ 5,743,787	$ 73,756,368	$ 89,543	$ 6,166	$ 1,413
i=b-g	Energy	$ 182,796,665	$ 69,800,146	$ 4,440,305	$ 15,378,890	$ 17,684,594	$ 3,754,350	$ 69,788,797	$ 68,149	$ 1,595,563	$ 285,871
j=c	Dist Primary	$ 72,512,797	$ 42,843,798	$ 3,067,924	$ 10,665,215	$ 9,320,681	$ 2,209,680	$ 4,195,444	$ 36,121	$ 143,067	$ 30,867
k=d	Dist Secondary	$ 32,012,721	$ 21,213,526	$ 1,636,335	$ 4,559,449	$ 2,944,372	$ 985,794	$ 69,612	$ 12,829	$ 507,729	$ 83,075
l=e	Customer	$ 25,589,466	$ 12,249,602	$ 3,465,334	$ 1,188,363	$ 468,678	$ 61,338	$ 256,346	$ 1,530	$ 6,791,546	$ 1,106,729
m = sum h-l		$ 556,664,349	$ 250,313,594	$ 20,269,809	$ 58,631,418	$ 55,867,814	$ 12,754,949	$ 148,066,567	$ 208,172	$ 9,044,071	$ 1,507,955

Full Cost Basic Service Charge Calculation
Kentucky Power Company

Residential					
		Dist. Primary Demand	**Dist. Secondary Demand**	**Distribution Customer Services & Accounts**	**Distribution Total**
Distribution Revenue Requirement (CCOS)		$42,843,798	$21,213,526	$12,249,602	$ 76,306,926
Fixed Distribution Plant Allocation Factors		78%	77%	100%	
Fixed Distribution Plant Revenue Requirement		$ 33,419,297	$ 16,434,421	$12,249,602	$ 62,103,320
Residential Bills					
1,639,281		20.39	10.03	7.47	
1,637,416	RS				
1,865	RSTOD				
Full Cost Basic Service Charge		**$37.88**	**per customer per month**		

Marginal Customer Connection Study
Kentucky Power 2017

Kentucky Power (Customer Hookup Cost): 7.2kV				
Account	Description	Total Installed Cost	% of Total Cost	Avg Serv Life (yrs)
3640000	Poles, Towers & Fixtures	$1,443.86	35.75%	31
3650000	OH Conductor & Devices	$866.52	21.46%	40
3680000	Transformer Devices	$1,363.28	33.76%	32
3690000	Services	$253.52	6.28%	33
5860000	Meter Expense	$111.54	2.76%	25
Total Work Request Charges		$4,038.72		

Marginal Cost Per Month to Connect a Residential Customer	
Weighted Avg Accounting Life	33
Levelized 34 Year Carrying Charge	11.56%
Total Capital Cost	$4,038.72
Monthly Capital Recovery $	$38.91
Total Basic Service Charge $/month	**$38.91**

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended February, 28, 2017

					Proposed Revenue Allocation					
Current Class (1)	**Current Revenue** (2)	**Rate Base** (3)	0 **Current Income** (4)	**Current ROR %** (5)	**Income Increase** (6)	**Income** (7)	**ROR %** (8)	**Revenue Increase** (9)	**Sales Revenue** (10)	**Percent Increase** (11)
RS	216,341,050	652,486,366	7,048,662	1.08	22,660,786	29,709,448	4.55	37,237,355	253,578,405	17.21
SGS	18,632,507	37,514,381	3,959,664	10.56	1,125,152	5,084,816	13.55	1,848,907	20,481,414	9.92
MGS	53,484,637	114,971,829	9,505,162	8.27	3,579,804	13,084,966	11.38	5,882,515	59,367,152	11.00
LGS	51,515,378	101,363,382	8,399,008	8.29	3,155,140	11,554,148	11.40	5,184,686	56,700,064	10.06
IGS	139,030,771	240,509,510	13,166,219	5.47	7,824,469	20,990,688	8.73	12,857,564	151,888,335	9.25
PS	11,535,619	26,428,694	1,631,776	6.17	850,553	2,482,329	9.39	1,397,672	12,933,291	12.12
MW	194,881	337,885	37,818	11.19	10,026	47,844	14.16	16,476	211,357	8.45
OL	8,254,025	18,839,286	2,836,123	15.05	522,655	3,358,778	17.83	858,854	9,112,879	10.41
SL	1,411,343	2,437,113	382,116	15.68	66,851	448,967	18.42	109,853	1,521,196	7.78
Total	500,400,211	1,194,888,447	46,966,548	3.93	39,795,436	86,761,984	7.26	65,393,882	565,794,093	13.07

RIDER R.P.O.
(Renewable Power Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P. and M.W. tariffs. T T

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants. T

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. N N

CONDITIONS OF SERVICE.

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage. T T

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers. T T

RATES. T

Option A: T

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item. T

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

A1. Solar RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month	N
All Usage Purchase:	Charge: $0.010/kWh consumed	N

(Cont'd on Sheet 31-2)

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TITLE: Director Regulatory Services

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In Case No. 2017-00179 Dated XXXXXXX

RIDER R.P.O. T
(Renewable Power Option Rider) T

RATES. (Cont'd)

A2. Wind RECs: N

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month
All Usage Purchase:	Charge: $0.010/kWh consumed

A3. Hydro & Other RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 0.30/month
All Usage Purchase:	Charge: $0.003/kWh consumed

Option B:

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer. N

TERM.

This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice. T T T

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer. T

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program. T

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KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 6-10
CANCELLING P.S.C. KY. NO. 11 _________ SHEET NO. 6-10

N

TARIFF R. S. D.
(Residential Demand-Metered Electric Service)

AVAILABILITY OF SERVICE.

Available for residential electric service through one single-phase multiple-register demand meter. Availability is limited to the first 1,000 customers applying for service under this tariff.

MONTHLY RATE.

Service Charge .... $ 17.50 per customer

Energy Charge
All KWH used during on-peak billing period..................13.747¢ per KWH
All KWH used during off-peak billing period.................. 7.418¢ per KWH

Demand Charge .... $4.44 for each KW of monthly billing demand

For the purpose of this tariff, the on-peak billing period is defined as follows:
Months of October – May.................7:00 A.M. to 11:00 A.M for all weekdays
Months of June – September ....4:00 P.M to 9:00 P.M for all weekdays
The off-peak billing period is defined as all weekday hours not defined above as on-peak hours and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

ADJUSTMENT CLAUSES.

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 5
System Sales Clause	Sheet No. 19
Franchise Tariff	Sheet No. 20
Demand-Side Management Adjustment Clause	Sheet No. 22
Home Energy Assistance Program	Sheet No. 24
Kentucky Economic Development Program	Sheet No. 25
Capacity Charge	Sheet No. 28
Environmental Surcharge	Sheet No. 29
School Tax	Sheet No. 33
Purchase Power Adjustment	Sheet No. 35
Decommissioning Rider	Sheet No. 38

MONTHLY BILLING DEMAND.

Customer's demand will be taken monthly to be the highest registration of a 15 minute integrating demand meter or indicator during the on-peak period.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, and additional charge of 5% of the unpaid portion will be made.

N

(Cont'd on Sheet No. 6-11)

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TARIFF R.S. D. (Cont'd)
(Residential Demand-Metered Electric Service)

N

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

N

TARIFF P.P.A.
(Purchase Power Adjustment)

T

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

RATE.

The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

   PPANC= N+RP+CSIRP+G+OATT-BPP

   Where:
   BPP=The annual amount of purchase power costs included in base rates, $79,076,785.

   a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
   b. RP = The annual purchased power costs not otherwise recoverable in the Fuel Adjustment Clause including but not limited to the cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages and the cost of purchases in excess of the highest cost owned or leased unit.
   c. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.
   d. G= The annual gains and losses on incidental gas sales; and
   e. OATT= The net annual PJM load-serving entity Open Access Transmission Tariff Charges.

(Cont'd on Sheet No. 35-2)

T

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N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	\$/kWh	\$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	\$0.00000	--
S.G.S.-T.O.D.	\$0.00000	--
M.G.S.-T.O.D.	\$0.00000	--
G.S.	\$0.00000	--
L.G.S., L.G.S.-T.O.D.	\$0.00000	\$0.00
L.G.S.-L.M.-T.O.D.	\$0.00000	--
I.G.S. and C.S.-I.R.P.	\$0.00000	\$0.00
M.W.	\$0.00000	--
O.L.	\$0.00000	--
S.L.	\$0.00000	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS and IGS tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet No. 35-3)

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TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES. (Cont'd)

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.

2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.

3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.0240909%	
S.G.S.-T.O.D.		0.0196553%	
M.G.S.-T.O.D.		0.0196553%	
G.S.		0.0196553%	
L.G.S., L.G.S.-T.O.D		0.0170480%	
L.G.S.-L.M.-T.O.D.		0.0170480%	
I.G.S. and C.S.-I.R.P.		0.0118222%	
M.W.		0.0135480%	
O.L.		0.0000000%	
S.L.		0.0000000%	

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.

7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.34% and the KPSC Maintenance Fee of 0.1941% and other similar revenue based taxes or assessments occasioned by the Big Sandy Unit 1 Operation Rider revenues.

9. The annual PPA factors shall be filed with the Commission by August 15 of each year, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

N
N

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By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

Calculation of Proposed Peaking Unit Equivalent Cost Calculation Adjustment

	Firm Gas Adjustment Calculation					
	$/MMBtu	Heat Rate	$/MWh	Startup Costs $/MWh	Variable O&M $/MWh	Total $/MWh Adjustment
January	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
February	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
March	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
April	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
May	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
June	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
July	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
August	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
September	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
October	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
November	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
December	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87

Proposed new Peaking Unit Equivalent cost calculation = (Daily Gas Price * Heat Rate/1000) + Total $/MWh Adjustment

Firm Reservation Rate, per Big Sandy Agreement ($.20/MMBtu)
Firm Surcharges, as stated in TCO tariff ($.0545/MMBtu)
Firm Transportation Commodity Rate ($0.0104/MMBtu)
Transportation Retainage, as stated in TCO tariff (1.893% or ~$0.058 on $3 gas)
Park and Lend Rate, as stated in the TCO tariff ($0.1939 winter and $0.1327 summer)
FERC Annual Charge Adjustment (ACA) ($0.0013/MMbtu)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

DIRECT TESTIMONY OF

KATHARINE I. WALSH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Katharine I. Walsh, being duly sworn, deposes and says she is a Regulatory Consultant Principal for American Electric Power that she has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of her information, knowledge and belief

Katharine I Walsh

Katharine I Walsh

STATE OF OHIO)
) CASE NO. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Katharine I Walsh, this the 21 day of June 2017.

Princess Brown

Notary Public

My Commission Expires: 4/19/2020

NOTARIAL SEAL STATE OF OHIO

Princess M. Brown
Notary Public, State of Ohio
My Commission Expires 04-19-2020

DIRECT TESTIMONY OF
KATHARINE I. WALSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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**DIRECT TESTIMONY OF
KATHARINE I. WALSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A. My name is Katharine I. Walsh. I am employed by American Electric Power Service Corporation ("AEPSC") as a Regulatory Consultant Principal in the Regulated Pricing and Analysis Department. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS A REGULATORY CONSULTANT IN THE REGULATORY PRICING AND ANALYSIS DEPARTMENT?

A. My responsibilities include preparing cost of service studies for regulatory filings and providing regulatory support and analysis for pricing matters associated with Kentucky Power, and other AEP electric utility operating companies.

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

A. I received a Bachelor of Science in Economics from Xavier University in 2008. In 2008 I joined AEPSC as an Energy Analyst in the Commercial Operations Group.

In 2010, I transferred to Regulatory Services as a Regulatory Analyst. In 2017, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THIS OR OTHER UTILITY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony before the State Corporation Commission of Virginia on behalf of Appalachian Power Company, an AEP subsidiary and affiliate of Kentucky Power. Additionally, I participated in an informal conference at the Commission on September 1, 2016 to discuss the Company's annual Big Sandy Retirement Rider update.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony is to support the Kentucky Power jurisdictional cost of service study through which the cost to provide service to the Company's retail customers is developed. A copy of the Kentucky Power jurisdictional cost of service study is included as Section V.

IV. COST OF SERVICE STUDY OVERVIEW

Q. WHAT IS THE SOURCE OF THE DATA USED IN THE COMPANY'S JURISDICTIONAL COST OF SERVICE STUDY?

A. The Company follows the Uniform System of Accounts as prescribed by FERC and adopted by this Commission. The Uniform System of Accounts sets the guidelines for recording assets, liabilities, income and expenses into various accounts. The costs recorded in each FERC account are examined to verify compliance with these guidelines and may be adjusted to reflect the Commission's policies and known and measurable changes to the test year level of expenditures.

Q. HOW IS THE INFORMATION USED TO ALLOCATE COSTS TO KENTUCKY POWER'S RETAIL CUSTOMERS?

A. The costs recorded by FERC account are per book amounts pertaining to electric utility operations of the Company for service supplied to all customers, both wholesale and retail. Kentucky Power's retail revenue is approximately 99% of its total firm sales revenue. The Company's wholesale revenue, which includes sales to the cities of Olive Hill and Vanceburg, is approximately 1% of its total revenue. It is therefore, necessary to identify and segregate costs related only to providing service to Kentucky Power's retail customers.

Q. EXPLAIN HOW THE REVENUE REQUIREMENT IS DETERMINED FOR KENTUCKY POWER'S RETAIL CUSTOMERS.

A. A three-step process is followed to assign and allocate costs to determine the total revenue requirement for the Company's retail customers. These three steps are the functionalization of costs, the classification of costs, and the allocation of costs. By following this process the Company is able to identify and segregate the costs related to providing service to Kentucky Power's retail customers.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. Once the data is gathered, the costs are then separated by functional group as follows:

1) Production and Purchased Power costs;

2) Transmission costs;

3) Distribution costs;

4) Customer Service costs; and

5) Administrative and General (A&G) costs.

Q. PLEASE DESCRIBE EACH OF THESE FUNCTIONAL GROUPS.

A. The production and purchased power functional group includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission functional group consists of the costs associated with the high voltage system utilized for the bulk transmission of power from generation sources to the load centers, and to and from interconnected utilities. The distribution functional group includes the radial distribution system that connects the transmission system and the ultimate customer. The customer service functional group encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. Finally, the A&G functional group includes costs not directly assignable to other cost functions.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. Once costs have been segregated by functional group, the Company separates the costs within each functional group into separate classifications. The Company utilized the following classifications as part of its cost of service study: 1) demand costs (costs associated with the kW demand imposed by the customer), 2) energy costs (costs that vary with the number of kilowatt hours used by the customer), 3) customer costs (costs that are directly related to the number of customers served) and 4) labor costs (costs that are directly related to payroll expenses associated with serving the customer). The Company classified costs within each functional group as follows:

<u>Function</u>	<u>Classification</u>
Production and Purchased Power costs	Demand, Energy
Transmission costs	Demand
Distribution costs	Demand, Customer
Customer Service costs	Customer
A&G costs	Labor

Production plant costs, such as depreciation and return on investment, are considered to be demand-related costs. Most fuel and production operation and maintenance (O&M) expenses are energy-related because they vary with the quantity of energy produced. Transmission costs are demand-related because they are fixed and do not vary with energy usage. Generally, the distribution system costs are affected by either demand or by the number of customers served. Demand-related distribution costs will usually vary with the size of the load served, while customer-related distribution costs vary with the number of customers receiving the service. The classification process provides a basis on which to allocate different categories of costs (demand, energy or customer) to the utility's jurisdictions.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. Once the costs have been functionalized and classified, the third and final step is for the Company to allocate those costs among retail and wholesale customers based on how the costs are incurred for each. In other words, the allocation process assigns costs to customers subject to the Commission's jurisdiction (retail customers) or

FERC's jurisdiction (wholesale customers). The allocation process is a reasonable, appropriate, and understandable method to assign costs as between the Company's retail and wholesale customer classes.

Some costs are directly assignable to a jurisdiction. For example, costs related to regulatory deferrals are associated with a specific jurisdiction and are directly assigned to that jurisdiction. Most costs, however, are attributable to both of the Company's jurisdictions. These are joint costs and must be allocated to the jurisdictions by an allocation methodology that is based on the classification described above for that cost.

Q. ARE THE ALLOCATION METHODS EMPLOYED BY THE COMPANY CONSISTENT WITH COST OF SERVICE PRINCIPLES?

A. Yes. The allocation methodologies utilized in the Company's jurisdictional cost of service study were chosen after giving consideration to cost causation principles. The results of the jurisdictional cost of service study can be relied upon to determine the appropriate revenue requirement for the Company's retail customers.

Q. ARE YOU RESPONSIBLE FOR THE METHODOLOGY USED IN THE PREPARATION OF THE KENTUCKY POWER JURISDICTIONAL COST OF SERVICE STUDY?

A. Yes. I developed the allocation methodology and the allocation factors used to calculate the Kentucky Power's retail jurisdictional cost of service. The basic methodology used in this case is the same methodology used in the Company's last several rate cases.

V. ALLOCATIONS

Q. PLEASE DESCRIBE HOW THE ENERGY ALLOCATION FACTOR (EAF) WAS DETERMINED.

A. First, total retail customer test year sales of energy (in kWH) were accumulated. Next, the total sales of energy was adjusted to the generation level by applying the appropriate transmission and distribution loss factors to obtain the generation-level energy sales to retail customers. Finally, the retail generation-level sales were divided by the net total Company generation-level energy sales to obtain the retail energy allocation factor.

Q. PLEASE DESCRIBE HOW THE DEMAND ALLOCATION FACTOR (PDAF) WAS DETERMINED.

A. One basis for allocating the elements of the cost of property between retail and wholesale customers is the respective contribution by each of the two classes to the Company's peak demand. The PDAF reflects the coincident demand of the Company's retail customers at the time of Kentucky Power's monthly peak demand (the "coincident peak demand). In other words, it represents the kilowatt contribution of retail customers to the Company's monthly peak demand.

The production demand allocation factor was calculated by dividing the average of the twelve monthly retail class coincident demands, adjusted for losses to the generation levels, by the average of the twelve monthly total Company internal peak demands. The transmission and sub-transmission demand allocation factors are the same as the production demand allocation factor.

The remaining allocators are internally calculated within the study and can be found on Section V, Allocation Factors.

Q. PLEASE DESCRIBE ANY ADJUSTMENTS MADE TO THE PDAF AND EAF ALLOCATORS.

A. Kentucky Power removed one of its retail customers, Kentucky Electric Steel, from the test year levels of energy and demand in order to create the PDAF and EAF allocators. Kentucky Electric Steel declared bankruptcy during the test year and began to significantly decrease load over the course of 2016 and 2017. Accordingly, it was appropriate to remove their contribution to the allocators used in determining the appropriate level of demand and energy attributable to Kentucky Power's retail customers. These adjustments can be seen on Section V, Schedules 9 and 10.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S ELECTRIC PLANT IN SERVICE.

A. Electric plant in service was separated into different plant categories by function and then allocated accordingly. Kentucky Power's production plant was allocated to the two jurisdictions using the production demand allocation factor (PDAF). Transmission plant was allocated using the transmission demand allocation factor (TDAF). Distribution plant was directly assigned to Kentucky Power's retail customers with the exception of Olive Hill substation and meter costs. General and intangible plant was allocated using gross plant production, transmission and distribution factor (GP-PTD).

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. Kentucky Power's Accumulated Provision for Depreciation and Amortization were functionalized and classified in a fashion similar to Kentucky Power's Electric Plant in Service. Production, transmission and distribution accumulated depreciation was allocated using the same process as the allocation of the associated plant. General and Intangible plant accumulated depreciation was allocated by GP-PTD factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S OTHER RATE BASE COMPONENTS.

A. Electric Plant held for Future Use, Construction Work in Progress and Allowance for Funds Used during Construction were booked by functional group and then allocated using the associated plant factors. The Carrs Site, which represents the majority of the production-related Plant Held for Future Use is removed from KPCo Plant Held for Future Use prior to the allocation process. This is consistent with past treatment of this item.

Fuel and Allowance Inventory were allocated using the energy allocation factor (EAF). Materials and Supplies were separated into functional groups and allocated by associated plant factors accordingly. Materials and Supplies other components, such as Lime, Limestone, Urea and Urea In-Transit are allocated using the EAF. Prepayments were allocated using the gross plant total allocation factor (GP-TOT).

The Cash Working Capital component is calculated by using the standard formula of one-eighth of Total Company O&M expenses. This equals one and one half months of the Company's O&M expenses.

Accumulated Deferred Investment Tax Credit amounts were provided by Company Witness Bartsch. Customer Advances and Customer Deposits are a result of the Company's retail operations and, therefore, 100% of these amounts are allocated to Kentucky Power's retail cost of service.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S OPERATING REVENUES.

A. Sales revenue was directly assigned to each jurisdiction where possible. Demand-related system sales revenue was allocated based on the PDAF. Energy-related system sales revenue was allocated on the EAF.

Forfeited Discounts and miscellaneous service revenues were a result of the Kentucky Power's retail operations and therefore directly assigned 100% to the Company's retail customers.

Rent from electric property, other electric revenue, and various transmission agreement revenues were allocated to jurisdictions based on the corresponding functional allocator or directly assigned to Kentucky Power's retail customers where applicable.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S OPERATING AND MAINTENANCE EXPENSES.

A. Production-related Operation and Maintenance (O&M) expenses were classified as either demand or energy-related. The demand component was allocated using the PDAF and the energy component was allocated using the EAF.

Transmission-related O&M was allocated based on the gross plant transmission (GP-TRANS) allocation factor or directly assigned as applicable.

Distribution-related O&M was allocated based on the gross plant distribution (GP-DIST) allocation factor or directly assigned as applicable.

Customer Accounts, Customer Information and Customer Service expense were classified as customer-related and allocated on the total number of customers.

In general, Administrative and General (A&G) expenses were allocated using the A&G allocator which is derived based on how the non-A&G O&M expenses were allocated.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S DEPRECIATION AND AMORTIZATION EXPENSE.

A. Depreciation and Amortization were booked by functional group then allocated using the associated plant factors.

Q. PLEASE EXPLAIN HOW KENTUCKY POWER'S TAXES OTHER THAN FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.

A. Taxes Other than Income Taxes were classified as relating to payroll, property, revenue, demand or energy and allocated accordingly or directly assigned. Payroll taxes are related to labor and allocated on the payroll allocation factor (OML). Property taxes were allocated using the GP-TOT allocation factor.

Q. PLEASE EXPLAIN HOW KENTUCKY POWER'S FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.

A. For details on Federal and State Income Taxes, please see Company Witness Bartsch's testimony and supporting tax schedules.

Q. PLEASE EXPLAIN HOW ADJUSTMENTS FOR KENTUCKY POWER WERE INCORPORATED INTO SECTION V.

A. Adjustments to test year revenues and operating expenses were provided to me by way of individual worksheets compiled and prepared by various Company witnesses based on their expertise. I added the retail adjustments to the Company's retail per books cost of service amounts to arrive at the going-level Kentucky Power jurisdictional cost of service.

Q. PLEASE EXPLAIN ANY DIFFERENCES IN PRESENTATION, FROM PAST FILINGS, IN THE FORMAT OF THE COMPANY'S JURISDICTIONAL COST OF SERVICE STUDY.

A. For purposes of clarity and providing better detailed support, all adjustments are now included in the numbered going level adjustments and can be found on Section V Schedule 5. The Company's jurisdictional cost of service study no longer utilizes eliminating/reclassification adjustments prior to incorporating going level adjustments.

Q. PLEASE EXPLAIN THE REASON FOR THE DEPARTURE FROM THE FORMAT USED IN PAST JURISDICTIONAL COST OF SERVICE STUDIES OF THE COMPANY.

A. The new format provides greater detail and auditability as all adjustments are numbered and detail can be found in witnesses' workpapers. This new format should benefit the Parties to the case in their review of the Company's Cost of Service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2017-00179
COUNTY OF BOYD	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 21st day of June 2017.

Trisha M. Young Blum

Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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**DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A. My name is Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power in 1978 in various customer services and accounting positions. In 1983, I transferred to Kentucky Power Company working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 and oversaw all billing and collection activity for the Company. I transferred in 1998 to Appalachian Power Company and began work in rates. I transferred in 2001 to the AEP Service Corporation and worked as a Senior Rate Consultant. In July 2004, I assumed the position of Manager, Business Operations Support and was promoted to Director in April 2006. I was promoted to my current position as Managing Director, Regulatory and Finance effective September 1, 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR, REGULATORY AND FINANCE?

A. I am primarily responsible for managing the regulatory and financial strategy for Kentucky Power. This responsibility includes planning and executing rate filings for both federal and state regulatory agencies and certificate of public convenience and necessity ("CPCN") filings before this Commission. I am also responsible for managing the Company's financial operating plans including the preparation, coordination and review of various capital and O&M operating budgets. As part of developing and implementing the Company's financial strategy, I work with various departments within American Electric Power Service Corporation to ensure that adequate capital resources are available to build, operate, and maintain Kentucky Power's electric system assets. The goal of this effort is providing safe, reliable, and cost-effective service to our customers. In my role as Managing Director, Regulatory and Finance, I report directly to Matthew J. Satterwhite, President and Chief Operating Officer of Kentucky Power.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified before this Commission in various fuel review proceedings and filed testimony in the Company's four most recent base rate case filings, Case No. 2005-00341, Case No. 2009-00459, Case No. 2013-00197 and Case No. 2014-00396. Other cases in which I have testified include an environmental compliance plan, Case No. 2011-00401; a real-time pricing proceeding, Case No. 2012-00226; the transfer of the Mitchell Generating Station to Kentucky Power, Case No. 2012-00578; the CPCN filing to convert Big Sandy Unit 1 to a gas-fired unit, Case No. 2013-00430; a DSM application, Case No. 2014-00271; and a FAC review proceeding, Case No. 2014-00225.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support: (1) the revenue requirement being proposed by the Company; (2) adjustments to the Company's capitalization; (3) certain known and measurable adjustments to test year revenues and operating expenses; and (4) the request for establishment of new regulatory assets or liabilities and the amortization of existing regulatory assets. I also describe the Company's activities during the 30-day extension granted by the Commission for filing this application.

IV. FILING REQUIREMENTS

Q. PLEASE DESCRIBE SECTION IV OF THE COMPANY'S FILING.

A. Section IV of the Company's filing is the financial exhibit required by 807 KAR 5:001, Section 12. Balance sheet data is shown as of February 28, 2017, and income statement data is for the twelve months ended February 28, 2017. By Order dated May 24, 2017 the Commission granted the Company's motion for a deviation from the ninety-day requirement of 807 KAR 5:001, Section 12(1)(a) thereby allowing the Company to utilize a financial exhibit covering a twelve-month period ending more than 90 days from filing of the Company's application.

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S REGULATIONS REQUIRING CERTAIN ADDITIONAL DATA TO BE FILED?

A. Yes. The information required to be filed with a general rate case, including those set forth in 807 KAR 5:001, Section 16, are presented in Section II (filing requirements) of the Company's filing, Section III (testimony), and Section V (adjustments).

Q. ARE YOU SPONSORING ANY SCHEDULES IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the summaries and details of the Capitalization and Rate Base amounts, and the adjustments to the "per books" values. These schedules are located in Section V of the Company's filing. In particular, I am sponsoring the following Schedules:

- Schedule 1: Fully Adjusted Base Case Summary
- Schedule 2: Revenue Requirement
- Schedule 3: Capitalization
- Schedule 4: Adjustment Summary

I am also sponsoring a number of specific adjustments to test year revenues and expenses contained in Schedule 4 (Adjustment Summary) and identify the specific workpaper sheet number where appropriate.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT PORTIONS OF THE INFORMATION CONTAINED IN THE SUMMARIES AND ADJUSTMENTS ARE YOU SPONSORING?

A. I am responsible for the total Company amounts shown or used to derive the Kentucky Power retail jurisdictional amounts. Company Witness Walsh furnished the Kentucky Power retail jurisdictional amounts and the allocation factors required to calculate such amounts. Company Witness Walsh also is responsible for the allocation methodology.

V. PROPOSED INCREASE IN ANNUAL REVENUES

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT BEING PROPOSED BY THE COMPANY.

A. The Company is proposing a total annual revenue requirement of $619,288,965. This represents an increase of $65,387,987 over the Test Year ended February 28, 2017 adjusted revenues of $553,900,978, an increase of approximately 11.8%. Kentucky Power also is proposing additional customer funding for the Home Energy Assistance Program ("HEAP") and the Kentucky Economic Development Surcharge ("KEDS") of $81,667 and $203,224 respectively, for a total of $284,891, or an additional increase of approximately 0.06%. Kentucky Power will match the additional customer funding of HEAP and KEDS. With the additional customer HEAP and KEDS funding, the increase in Kentucky Power's annual revenue requirement totals $65,672,878, or an approximate 11.86% increase over the adjusted test year revenues. Finally, the Company is proposing a revenue increase of $3,903,056 in connection with the 2017 Environmental Compliance Plan ("2017 ECP"). The total increase in revenue will be

$69,575,934 or an increase of approximately 12.56%. Please refer to Section V, the Summary Tab for the derivation of the proposed revenue requirement.

Q. CAN YOU SUMMARIZE THE DEVELOPMENT OF THE PROPOSED BASE CASE ANNUAL REVENUE REQUIREMENT?

A. The development of the revenue requirement increase is shown on Schedule 1 (Fully Adjusted Base Case Summary) of Section V of the Company's filing. Schedule l summarizes the components of Net Electric Operating Income for the twelve months ended February 28, 2017, as adjusted, under present rates in Column 3; and the effects of the proposed rate increase on those components in Column 4. Also shown are the components of Net Electric Operating Income after giving effect to the proposed rate increase in Column 5. The total amount of rate base and capitalization is also shown, along with the calculated overall rates of return.

Q. PLEASE EXPLAIN WHAT SCHEDULE 2 (REVENUE REQUIREMENT) OF SECTION V ILLUSTRATES.

A. Schedule 2 shows how Kentucky Power derived the proposed revenue increase of $65,393,885 in the Company's base case annual revenue requirement. The rates proposed by the Company are designed to produce $65,387,987 in annual revenues as shown on the Summary tab of Section V.

Q. PLEASE DESCRIBE THE INFORMATION PROVIDED BY SCHEDULES 3 (CAPITALIZATION) AND 4 (ADJUSTMENT SUMMARY) OF SECTION V.

A. Schedule 3 shows the Company's development of the adjusted capitalization amount used to develop the base case annual revenue requirement. Schedule 4 identifies the known and measurable adjustments to test year revenue, expenses and rate base. Details of each adjustment are shown in the workpapers to Schedule 4.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL WITH RESPECT TO THE HEAP SURCHARGE AND ITS EFFECT ON KENTUCKY POWER'S ANNUAL REVENUE REQUIREMENT.

A. The Company proposes to increase the monthly HEAP surcharge to recover an additional $0.05 cents per residential customer per month to provide additional funds to local community action agencies to assist those customers who need help in paying their electric bills. This will increase the total monthly amount from $0.15 to $0.20 cents per residential bill. This will provide $81,667 of additional revenue from Kentucky Power's customers. Kentucky Power will match the increased customer HEAP payments. The customer and Company increased amounts will provide local community action agencies with an additional $163,334 to be distributed to customers in need of help to pay their monthly electric bills.

Q, WHAT IS KENTUCKY POWER PROPOSING WITH RESPECT TO KEDS?

A. The Company proposes to increase the monthly KEDS amount to recover an additional $0.10 cents per customer per month to fund additional efforts by local businesses and communities to bring additional jobs and customers into our service territory. This will increase the total monthly amount from $0.15 to $0.25 cents per customer bill providing $203,224 in additional revenue. The Company will match the $0.10 cents increase for a total of $406,448 in additional economic development funding to be distributed through economic development grants as described by Company Witness Hall.

Q. PLEASE EXPLAIN THE 2017 ECP COMPONENT OF KENTUCKY POWER'S ANNUAL REVENUE REQUIREMENT.

A. The proposed 2017 ECP will increase Kentucky Power's revenue requirement by $3,903,056. Company Witnesses McManus, Bartsch, McKenzie, Miller, Osborne, and Elliott provide specific information concerning the 2017 ECP and the recovery of the costs through Tariff E.S. The proposed base case revenue requirement plus the proposed additional three components (ECP, HEAP, and KEDS) produce a total increase in the Company's annual revenue requirement of $69,575,934.

Q. IS KENTUCKY POWER PROPOSING TO EQUALIZE RATES OF RETURN ACROSS ALL CUSTOMER CLASSES?

A. No. Equalizing rates of return for all customers would disproportionately require certain customer classes, particularly residential, to bear the effect of the proposed increase. The residential customer class has the lowest rate of return. Consistent with the Commission's long-standing policy of gradualism, this application makes small movement towards a more consistent rate of return across all customer classes. To this end, based upon the study performed by Company Witness Buck, Kentucky Power is proposing to reduce the residential class subsidy by 5%.

VI. CAPITALIZATION ADJUSTMENTS

Q. WOULD YOU PLEASE IDENTIFY AND EXPLAIN EACH OF THE CAPITALIZATION ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The Capitalization adjustments I am sponsoring are set forth in Section V, Schedule 3. Specifically, I am sponsoring the following capitalization adjustments:

Adjustment	Schedule 3
1. Decommissioning	Column 5
2. Mitchell FGD Consumables	Column 6
3. Mitchell FGD	Column 7
4. Mitchell Coal Stock	Column 8
5. Franklin Realty Company A/C 124	Column 9
6. Carrs Site	Column 10
7. Non-Utility Property	Column 11

Additional information regarding each of these capitalization adjustments is provided below.

Decommissioning
(Schedule 3, Column 5)

The Company removed from its capitalization all costs related to the decommissioning of Big Sandy Unit 2 and the other coal-related assets at the Big Sandy plant. Those costs are recovered exclusively through the Big Sandy Retirement Rider. Kentucky Power is proposing to change the name of this rider to the Decommissioning Rider.

Mitchell FGD Consumables
(Schedule 3, Column 6)

Kentucky Power removed all costs associated with consumables used in the operation of the flue gas desulfurization system (FGD) at the Mitchell Plant from base rates. Those costs are recovered exclusively through the environmental surcharge. Information regarding the derivation of Mitchell FGD consumables is included in the testimony of Company Witness Elliott.

Mitchell FGD Adjustment
(Schedule 3, Column 7)

As with the consumables used to operate the FGD, Kentucky Power removed the entire Mitchell FGD balance from base rates. Those costs will be recovered through the Company's Environmental Surcharge Tariff in conformity with the terms of the Stipulation and Settlement Agreement approved in Case No. 2012-00578.

Mitchell Coal Stock Adjustment
(Schedule 3, Column 8)

The coal inventory target at the Mitchell Plant is separately developed for the low and high sulfur coal piles. At February 28, 2017, the Mitchell Plant had 94,209 tons (Kentucky Power's 50% share) of low sulfur coal on hand at an average cost of $59.50 per ton, and a total value (on February 28, 2017) of $5,605,602. The target low sulfur coal inventory is 115,215 tons (Kentucky Power's 50% share). Thus, the difference between the February 28, 2017 low sulfur coal inventory and the target low sulfur coal inventory is 21,006 tons with a February 28, 2017 value of $1,249,691.

On February 28, 2017 the Mitchell Plant had 207,285 tons (Kentucky Power's 50% share) of high sulfur coal on hand at an average cost of $53.81 per ton and a total value (on February 28, 2017) of $11,153,949. The target inventory level for high sulfur coal is 57,608 tons (Kentucky Power's 50% share). Thus, the difference between the February 28, 2017 high sulfur coal inventory and the target high sulfur coal inventory yields an adjustment downward of 149,677 tons and a reduction in capitalization of $8,054,063.

The net difference (of both low and high sulfur coal) between the coal inventory value at Mitchell on February 28, 2017 and the target inventory value is a reduction in capitalization of $6,804,372. Because the coal inventory is usually financed with short-term debt, the Company first eliminated the short-term debt balance of $1,022,872 and then allocated the remainder of $5,781,500 ratably between long-term debt and common equity.

Franklin Realty Company Account No. 124 Property
(Schedule 3, Column 9)

Consistent with prior practice, the Franklin Realty Company (FRECO) investment, recorded in Account No. 124, was removed from the Company's capitalization.

Carrs Site Adjustment
(Schedule 3, Column 10)

Consistent with prior practice, the Carrs Site investment was removed from the Company's capitalization.

<u>Non-Utility Property</u>
<u>(Schedule 3, Column 11)</u>

Consistent with prior practice, the Non-Utility property investment was removed from the Company's capitalization.

Q. HOW ARE THE CAPITALIZATION ADJUSTMENTS ALLOCATED AMONG LONG-TERM DEBT, SHORT-TERM DEBT, AND COMMON EQUITY?

A. After the adjustment relating to coal stock, the Company allocated the capitalization adjustments ratably among long-term debt and common equity based on each component's percentage share of total capitalization at the end of the test year on February 28, 2017.

Q. WILL CAPITALIZATION BE UPDATED AT SOME POINT DURING THIS RATE PROCEEDING?

A. Yes. On June 19, 2017 and June 21, 2017, respectively, the Company refinanced its $65 million Pollution Control Bond due June 26, 2017 and its $325 million Senior Unsecured Note due September 15, 2017. Kentucky Power will promptly submit supplemental testimony detailing the terms and conditions of the new debt offerings, and also provide an updated Capitalization schedule and the effect of the refinancing on the original revenue requirement.

VII. <u>REVENUE AND OPERATING EXPENSE ADJUSTMENTS</u>

Q. WOULD YOU PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2. I am sponsoring the following adjustments:

	Adjustment Name	**Adjustment No.**
1.	Normalization of Major Storms	W17
2.	Amortization of Storm Cost Deferral	W18
3.	Amortization of Deferred NERC Costs	W30
4.	Plant Maintenance Normalization	W41
5.	Interest Synchronization	W49
6.	AFUDC Offset	W50
7.	Employee Complement Increase	W52
8.	Reduce Base Forestry Expense	W56

Additional information regarding each of these adjustments is provided below.

Normalization of Major Storms Adjustment
(Section V, Exhibit 2, Adjustment W17)

Q. HOW WAS THE MAJOR STORM NORMALIZATION ADJUSTMENT CALCULATED?

A. The Company adjusted its test year storm damage expense, less in-house labor, by using its three year average storm damage expense, less in-house labor, adjusted by the Handy-Whitman Contract Labor Index. Using the three year average, and deducting the test year level of storm damage expense, results in a jurisdictional increase to expenses of $595,932.

Amortization of Major Storm Deferral Adjustment
(Section V, Exhibit 2, Adjustment W18)

Q. HOW WAS THE AMORTIZATION OF MAJOR STORM DEFERRAL ADJUSTMENT CALCULATED?

A. In Case No. 2012-00445 the Commission authorized the Company to defer major storm costs of $12,146,000. These costs were subject to review in Kentucky Power's next base rate case. In Case No. 2014-00396, Kentucky Power proposed amortizing the $12,146,000 in storm costs over five years. The Company began amortizing those costs in July 2015 with the establishment of new base rates in Case No. 2014-00396. The amount amortized during the test year ending February 28, 2017 was $2,429,200. In Case No. 2016-00180 the Commission authorized the Company to defer additional major storm costs of $4,377,336. Recovery of the deferral was to be determined in Kentucky Power's next base rate proceeding following a review of the Company's storm preparedness, its response to system outages, and system reliability. Company Witness Phillips discusses these issues in his testimony. Kentucky Power proposes to amortize the 2016 regulatory asset over five years, beginning when new rates are established by the Commission in this case. The annual amount of amortization would be $875,467. The total adjusted annual major storm expense is $3,304,667. After subtracting the amount of $2,429,200 already in the test year, the adjustment is an $875,467 increase to expense.

<u>Amortization of Deferred NERC Costs</u>
<u>(Section V, Exhibit 2, Adjustment W30)</u>

Q. HOW WAS THE PROPOSED AMORTIZATION OF NERC COMPLIANCE AND CYBERSECURITY ADJUSTMENT EXPENSE CALCULATED?

A. Beginning July 1, 2015, the Company deferred costs related to new NERC Compliance and Cybersecurity initiatives as authorized by order date June 22, 2015 in Case No. 2014-00396. The order also indicated that subject to Commission review and approval in the Company's next base rate case, the NERC Compliance and Cybersecurity costs could be amortized over a five-year period. The Company deferred $71,374 in costs relating to NERC Compliance and Cybersecurity requirements from July 1, 2015 through February 28, 2017. The annual amortization of the deferred amount will be an increase to expense of $14,275.

Q. IS THERE, AS REQUIRED BY THE COMMISSION'S ORDER, A DIRECT RELATIONSHIP BETWEEN THE DEFERRED COSTS AND NERC OR CYBERSECURITY REQUIREMENTS?

A. Yes. Kentucky Power made the required March 31, 2016 and March 31, 2017 filings in compliance with the Commission's June 22, 2015 Order. The projects, associated NERC or cybersecurity requirement, and work order number are presented below:

- W/O SITC056001 - NERC-CIP v5 Upgrade - Program Management team costs for upgrades to systems and processes to enable readiness for the new v5 NERC CIP standards.
- W/O SITC151801– ECMP Agile Team - ECMP (End Point Configuration

Management) costs needed to support NERC CIP v5 Upgrade Program.

- W/O SITC152301 – Security Configuration Agile Team - Implementation of new tool “iDefender” to enable compliance with new NERC CIP v5 Configuration Management requirements.
- W/O SITC151901 – Firewall Management Tool Team - Implementation of new tool “Tufin” to enable compliance with new NERC CIP v5 Firewall Management requirements.
- W/O SITC151701 – ARCS Agile Team – ARCS (AEP’s Risk & Compliance Solution) updates needed to support new NERC CIP v5 requirements.
- W/O SITC152401 – ServiceNow Agile Team – ServiceNow updates needed to support new NERC CIP v5 requirements.
- W/O SITC152101 – IAM Agile Team – IAM (Identity & Access Management) updates needed to support new NERC CIP v5 requirements.
- W/O SITC156201 – IT Active Directory – Implementation of a new active directory domain to support new NERC CIP v5 requirements.
- W/O SITCB44601 – Physical Access Control – Implementation of new Physical Access Control System for NERC CIP v5 requirements.
- W/O SITCA40401 – Physical Access Management – Implementation of a new system for physical access management for NERC CIP v5 requirements.
- W/O SITCA55601 – PAM Cost for EACMS – Additional costs needed for implementation of a new system for physical access management (PAM) for NERC CIP v5 requirements surrounding EACMS (Electronic Access Control and Monitoring Systems).
- W/O SITCB45901 – Lenel OnGuard Upgrade – Implementation of new Physical Access Control System (Lenel OnGuard) for NERC CIP v5 requirements.

Plant Maintenance Normalization
(Section V, Exhibit 2, Adjustment W41)

Q. HOW WAS THE PLANT MAINTENANCE ADJUSTMENT CALCULATED?

A. Because Kentucky Power generating plant maintenance is performed on a multi-year cyclical basis, an adjustment to the test year plant maintenance expense is required to reflect an annualized on-going level of plant maintenance in the Company’s test year cost of service. Further information on the cyclical nature of steam plant maintenance is included in the testimony of Company Witness Osborne. Consistent with the approach taken in past cases, the Company first took the level of Mitchell steam plant maintenance expense for the twelve months ended February 28, 2015, 2016, and 2017 and adjusted those levels of plant maintenance expense to a constant dollar amount using the Handy-Whitman total steam production plant index. Next, the Company took the level of Big Sandy steam plant maintenance expense for nine months of actual expense (June 2016 – February 2017) and annualized that number to arrive at a twelve months ended level for February 28, 2017. Because Big Sandy Unit 1 lacked three years of operating history as a gas-fired generating unit, Kentucky Power used the annualized number for the twelve months ended February 28, 2017 as the three year average. The three year total was divided by three to arrive at an average annual normalized level of Mitchell and Big Sandy steam plant maintenance expense of $16,239,620. That result was compared to the test year level amount of $16,518,132. The difference of $278,512, when allocated to retail customers based on the PDAF allocation factor, results in an decrease to O&M expense to the test year cost of service of $274,334.

Q. HAS KENTUCKY POWER HISTORICALLY NORMALIZED STEAM PLANT MAINTENANCE EXPENSES?

A. Yes. Because the small size of the Company's generation portfolio and the cyclical nature of maintenance on those plants can result in significant year to year variation in steam plant expense, Kentucky Power has historically normalized steam plant maintenance expenses using a three-year average.

Q. IS THE COMPANY PROPOSING AN ADDITIONAL REQUEST FOR TREATMENT OF STEAM PLANT MAINTENANCE?

A. Yes. While the Company believes that normalizing steam plant maintenance expenses using a three-year average produces a going-level steam plant maintenance expense that is reasonable and appropriate, there can be years where the actual expense could be substantially greater or less than the average included in base rates. Adjustment W41 worksheet details the large variation in actual expense of steam plant maintenance for the Mitchell units among the three years. Because of this variance between years, the Company is seeking approval to defer the actual annual steam plant maintenance cost above or below the 3-year average included in base rates and establish a regulatory asset or liability as appropriate to be recovered by the Company or returned to the customer in the Company's next base rate case.

Interest Synchronization Adjustment
(Section V, Exhibit 2, Adjustment W49)

Q. WHY IS AN INTEREST SYNCHRONIZATION ADJUSTMENT NECESSARY?

A. This adjustment synchronizes the capital costs and capital structure included by the Company in this filing with the Federal and State Income Taxes included in the test period cost of service and the interest expense tax deduction that will result. The adjustment resulted in an increase to state income tax of $610,088 and an increase to federal income tax of $3,421,531 for a total increase to expenses of $4,031,619.

AFUDC Offset Adjustment
(Section V, Exhibit 2, Adjustment W50)

Q. PLEASE EXPLAIN THE AFUDC OFFSET ADJUSTMENT.

A. The February 28, 2017 balance of Construction Work In Progress ("CWIP") was used in the determination of Rate Base. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction (AFUDC) "offset" adjustment is being made to record AFUDC above the line. The CWIP balance was $27,165,803 on February 28, 2017, of which $2,411,402 is not subject to AFUDC. The remaining balance of $24,754,401 is subject to AFUDC. Using the requested overall return of 7.28%, the annualized AFUDC is $1,802,120. The AFUDC booked during the test year was $1,232,536 requiring an adjustment to increase the AFUDC offset by $569,584. The Deferred Federal Income Taxes (DFIT) associated with the borrowed funds portion of the $1,802,120 in Annualized AFUDC is $258,163. The booked DFIT on the borrowed funds portion was $183,664. This increases DFIT by $74,499.

Employee Complement Increase
(Section V, Exhibit 2, Adjustment W52)

Q. WHY IS KENTUCKY POWER INCREASING ITS EMPLOYEE COMPLEMENT?

A. The Company has or is in the process of adding five distribution employees since the end of the test year. Those employees are; a Safety Coordinator, two Distribution System Inspectors, and two administrative associates. The employees are being added: (1) to improve the safety of the Company's operations; (2) to increase the Company's oversight of its contractors; and (3) to improve the effectiveness of Kentucky Power's revenue protection efforts. The adjustment results in a jurisdictional increase to O&M expense of $172,594.

Q. WHY DID KENTUCKY POWER ADD A SAFETY COORDINATOR?

A. Safety takes precedence in everything Kentucky Power does as a Company. Every employee knows he or she can stop any job at any time if there is a concern for the safety of Kentucky Power's employees or the public. The Company is committed to ensuring that every employee goes home to her or his family in the same condition the employee came to work. The addition of the new Safety Coordinator (effective May 20, 2017) gives Kentucky Power two employees overseeing the actions of its over 200 distribution employees in its 20-county service territory. Responsibilities of the new safety coordinator include providing employees with additional proactive safety messages and instructions, on site job observations and constructive feedback, updating of safety manual, coordinating all safety training, inspecting all material yards for safety concerns, and inspection of all fleet vehicles for safety issues. Each of these actions are intended to allow the Company to continue to improve its safety culture.

Q. WHY IS KENTUCKY POWER ADDING EMPLOYEES TO INCREASE THE OVERSIGHT OF ITS CONTRACTORS?

A. The Company is committed to providing the highest level of quality work to ensure safe, reliable, and cost effective electric service to its customers. The Company currently utilizes 14 contract line crews with 59 contract line crew employees. The addition of two Distribution System Inspectors and an administrative associate to assist with in-office paper work will enable the

Company to better monitor the work of its line contractors to ensure they are performing their work in a safe and effective manner that complies with both AEP construction standards and the National Electric Safety Code. In 2016 the Company paid over $7 million in both capital and O&M labor to complete reliability projects, customer service work, and service restoration work. One Distribution System Inspector was added to our complement effective May 20, 2017, and a second was added effective June 17, 2017. Kentucky Power is currently interviewing applicants for the administrative associate position.

Q. DOES KENTUCKY POWER COMPANY CURRENTLY INSPECT THE WORK OF ITS DISTRIBUTION LINE CONTRACTORS?

A. Yes. However, currently there is only one Distribution System Inspector, who is located in Pikeville and who oversees the line contractors for all three districts. The addition of two additional inspectors (one in Ashland and one in Hazard districts) will allow for many more inspections across the entire service territory.

Q. WHAT IS THE PURPOSE OF THE REVENUE PROTECTION ADMINISTRATIVE ASSOCIATE?

A. Kentucky Power currently employs 1.5 Full Time Employee (FTE) to investigate and recover revenues lost through energy theft. This work, which protects the vast majority of the Company's 168,000 customers who abide by the law, is extremely labor intensive and requires both field and in-office investigation. Unfortunately, the 1.5 FTEs lack sufficient time to investigate and take the necessary steps to recover lost revenues associated with suspected cases of energy theft. The new administrative associate will be responsible for handling the in-house aspect of energy theft investigations. This in turn will permit the existing 1.5 FTEs to spend more time in the field doing on-site investigations. For 2015 and 2016 the Company recovered $287,991 and $333,395, respectively, of otherwise lost revenue resulting from the theft of energy. By freeing up the existing FTEs to do more on-site investigations, the Company estimates in can increase its annual energy theft recoveries by up to 50%. Kentucky Power currently is interviewing applicants for this position.

<u>Reduce Base Forestry Expense</u>
<u>(Section V, Exhibit 2, Adjustment W56)</u>

Q. WHY IS THERE A BASE FORESTRY ADJUSTMENT?

A. Company Witness Phillips explains in detail the reasons for the reduction in the Company's base forestry (Distribution Vegetation Management) expense. This results in a decrease to test year O&M expense of $6,794,282.

<u>Update of Big Sandy Unit 1 Depreciation</u>
<u>(Section V, Exhibit 2, Adjustment W43)</u>

Q. ALTHOUGH YOU ARE NOT SPONSORING THE ADJUSTMENT, WOULD YOU PLEASE ADDRESS THE ADJUSTMENT RELATED TO THE UPDATED DEPRECIATION RATES FOR BIG SANDY UNIT 1?

A. Yes. Company Witnesses Cash and Ross address the updated depreciation rates for Big Sandy Unit 1 following its conversion to a natural gas-fired facility and the resulting increase of $3,076,557 in test year expenses. I respectfully encourage the Commission to approve the updated Big Sandy Unit 1 depreciation rates and resulting adjustment. The Big Sandy Unit 1 depreciation rates were last adjusted in 1991. Since then Kentucky Power has made millions of dollars in capital investments and retirements at Big Sandy Unit 1. The undepreciated balance of Big Sandy Unit 1 as of February 28, 2017 is $108,757,835. In Case No. 2014-00396, Company Witness Davis stated that new depreciation rates will be required for Big Sandy Unit 1 after it is repowered to use natural gas in 2016. Further delay only exacerbates the problem of a large undepreciated balance by shifting the depreciation from the current customers who are enjoying the benefits of Big Sandy Unit 1 to later customers.

Q. WHY WERE THE BIG SANDY DEPRECIATION RATES NOT PREVIOUSLY ADJUSTED?

A. The primary driver was that during previous rate proceedings, in an effort to minimize the impact on current customers of required rate adjustments, Kentucky Power, in conjunction with the parties to the cases, agreed to forego adjusting depreciation rates.

Q. HAVE THE COMPANY AND ITS CUSTOMERS RECENTLY SEEN THE EFFECT OF FAILING TO UPDATE DEPRECIATION RATES?

A. Yes. In Case No. 2012-00578 the Commission approved a plan to recover over a 25-year period the retirement costs of coal-related assets of the Big Sandy plant. A large portion of those costs was the undepreciated balances of the plant assets. That balance was greater than it otherwise would have been because of the failure to keep depreciation rates current. Hindsight being 20/20, the Company, the parties, and the Commission need to be careful not to fall into the same trap created by failing to keep depreciation rates current.

VIII. TARIFF REVISIONS

Big Sandy Unit 1 Operation Rider (Tariff B.S.1.O.R.)

Q. IS THE BIG SANDY UNIT 1 OPERATION RIDER (B.S.1.O.R.) BEING ELIMINATED?

A. Yes. The B.S.1.O.R. was intended as an interim measure to permit the recovery of Big Sandy Unit 1's operating expenses and related capital costs pending its conversion to a gas-fired unit.

Q. WILL THERE BE AN OVER/UNDER BALANCE IN THE B.S.1.O.R. WHEN NEW BASE RATES GO INTO EFFECT?

A. Yes. The B.S.1.O.R. factors are modified annually and by definition provide for the recovery of any prior period under-recovery or over-recovery. Thus, there will be an under-recovery or over-recovery when the tariff is ended.

Q. HOW DOES THE COMPANY PROPOSE TO ACCOUNT FOR THE OVER/UNDER BALANCE OF THE B.S.1.O.R.?

A. The Company is requesting accounting authority permitting it to defer, and establish a corresponding regulatory asset or liability (as the case may be), in the amount of any under-recovery or over-recovery existing with respect to the B.S.1.O.R. when new base rates go into effect.

Q. WHEN IS THE COMPANY PROPOSING TO RECOVER OR REFUND THE BALANCE ESTABLISHED AS A REGULATORY ASSET OR LIABILITY?

A. The Company would present the regulatory asset or liability for recovery or refund in its next general base rate case proceeding.

IX. CASE REVIEW

Q. WHAT STEPS DID THE COMPANY TAKE TO PROVIDE THE COMMISSION AN ADEQUATE CASE IN CHIEF FOR REVIEW?

A. The Company took the following steps in reviewing the base rate case filing. First, the Company followed its normal prepare/check/review processes. Second, the Company added a peer check and review process where an employee outside of those normally used in the check and review process was assigned to check and review every adjustment, not only for accuracy of the adjustment, but also to ensure that those numbers linked backed properly to the cost of service section of the filing as well as individual direct testimony. This added time to the review process, but having those who are not normally close to the adjustment but understand how the adjustment should work, provided a fresh and different perspective during their review. The additional time taken during this case review resulted in a revised request of $69.6M versus the $70.4M previously noticed, an overall reduction of approximately $0.8M.

Q. DOES THE COMPANY FEEL CONFIDENT THAT THE CURRENT APPLICATION IS AN ACCURATE REPRESENTATION OF THE FACTS?

A. Yes. In taking the steps discussed in detail above, the Company is confident that it took every effort possible to file a complete and accurate application and minimize any potential issues.

Q. WILL THERE BE ANY FURTHER CHANGES AFTER THE APPLICATION IS FILED?

A. Yes. As mentioned in my testimony above, and in the testimony of Company Witness Miller, there will be a change to capitalization based upon the current offering to refinance the Company's $65 million Pollution Control Bond due June 26, 2017 and the Company's $325 million Senior Unsecured Note due September 15, 2017.

Q. WHY WAS THE JUNE 2017 REFINANCING NOT REFLECTED IN THE JUNE 28, 2017 APPLICATION?

A. The timing of the refinancing occurred as the procedural and logistical deadlines to file this rate application were passing. For filing with the Commission, 807 KAR 5:001, Section 17(2) and 807 KAR 5:011, Section 8(2) require the Company to provide public notice of the proposed rate request beginning at least one week prior to filing the application. To meet these requirements, as well as the publication schedules of the 20 newspapers in the Company's service territory, the Company was required to make the required rate calculations, prepare the notice, and submit it for publication by mid-June. Neither of the two refinancing transactions was completed in time to be included in the required legal notice. The effect of the June 2017 refinancing will be reflected in an update as soon as practicable.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.