COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	**CASE NO.**
ELECTRIC RATES AND FOR CERTIFICATES	**)**	**2016-00370**
OF PUBLIC CONVENIENCE AND NECESSITY	**)**	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION
DATED JANUARY 11, 2017

FILED: JANUARY 25, 2017

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Senior Vice President – Operations for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Kent W Blake
Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President – State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of January 2017.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Director – Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John P. Malloy**, being duly sworn, deposes and says that he is Vice President – Gas Distribution for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of January ___ 2017.

Notary Public (SEAL)

My Commission Expires:

April 17, 2019

ROBERT LEE MARTINEZ
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 4/17/2019
NOTARY ID 13019391-2

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott
Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

W. Seelye

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is President and Chief Operating Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W. Thompson

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President - Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John K. Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of January 2017.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER

Notary Public, State at Large, KY

My commission expires July 11, 2018

Notary ID # 512743

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 1

Responding Witness: Robert M. Conroy

Q-1. Refer to the Application, page 4, paragraph 6, which states that KU has a special contract with a customer receiving service under the Retail Transmission Service tariff wherein the customer is not charged the energy charge, fuel adjustment charge, and demand-side management ("DSM") cost recovery mechanism. Identify the customer referenced in this paragraph and explain why the customer does not pay these charges.

A-1. The customer referenced is the American Municipal Power, Inc. ("AMP") hydroelectric station in Foster, Kentucky ("AMP Meldahl"). KU filed its special contract concerning AMP Meldahl with the Commission in September 2014 and has an effective date of October 13, 2014, per the Commission's Tariff Branch. A copy of the special contract, which is available on the Commission's website, is attached for ease of reference.

As explained in the recitals of the Agreement for Back-Up Electric Service and Retail Electric Transmission Service ("Agreement"), AMP Meldahl is in KU's certified service territory, but is interconnected at the transmission level with Duke Energy Ohio, Inc. ("Duke Ohio"). As interconnected, AMP Meldahl's primary source of energy supply when the station is not self-supplying power is Duke Ohio, not KU. Therefore, although KU had and has exclusive retail service rights under KRS 278.018 for the territory where AMP Meldahl is located, KU acknowledged it would be economically impracticable for KU to provide the energy to serve AMP Meldahl across the transmission facilities interconnecting AMP Meldahl to Duke Ohio. But to protect KU's exclusive retail service rights, AMP Meldahl agreed to pay KU the non-energy and non-fuel charges of its Retail Transmission Service Standard Rate (Rate RTS) for any power that flowed into AMP Meldahl from Duke Ohio's transmission facilities, as more fully described in Exhibit 2 to the Agreement, which is the Special Contract for Retail Electric Transmission Service. As explained in the special contract, AMP Meldahl does not pay DSM charges because it is an industrial customer for DSM purposes, and KU did not then and does not now offer DSM programs to industrial customers, and therefore does not bill such customers DSM charges.

AMP Contract No. 2014-001082-MAS

AGREEMENT FOR BACK-UP ELECTRIC SERVICE AND RETAIL ELECTRIC TRANSMISSION SERVICE

This Agreement for Back-Up Electric Service and Retail Transmission Service ("Agreement") made and entered into this 9th day of September, 2014, by and between Kentucky Utilities Company, a Kentucky corporation ("Company"), and American Municipal Power, Inc., an Ohio corporation for non-profit ("Customer").

WITNESSETH:

WHEREAS, Customer is currently constructing, and will subsequently test, commission, synchronize to the grid, and commercially operate, a hydroelectric generating facility in Foster, Kentucky ("AMP Meldahl"), which lies in Company's certified electric retail service territory; and

WHEREAS, Company is currently providing electric service to AMP Meldahl at six delivery points under various rate schedules while Customer is constructing AMP Meldahl; and

WHEREAS, Customer has requested that Company provide permanent back-up power service at a single delivery point when AMP Meldahl transitions from its construction phase to its testing-and-commissioning phase (see Exhibit 1, Contract for Back-Up Electric Service, Contract No. 2014-001083-SCHED, attached hereto); and

WHEREAS, Customer requires, and PJM Interconnection L.L.C. ("PJM") will provide, electric transmission service to AMP Meldahl, which interconnects to the portion of the PJM transmission system owned by Duke Energy Ohio, Inc. ("DEO"); and

WHEREAS, Company has exclusive retail service rights under Kentucky Revised Statutes 278.018 for the territory where AMP Meldahl is located but acknowledges it would be economically impracticable for Company to provide the energy to serve AMP Meldahl across the transmission facilities interconnecting AMP Meldahl to DEO's transmission facilities ("Transmission Facilities"); and

WHEREAS, Company therefore will not supply any energy AMP Meldahl consumes from the Transmission Facilities, which energy entities other than Company will supply to AMP Meldahl according to the applicable rules, policies, and practices of PJM; and

WHEREAS, to protect Company's exclusive retail service rights, Customer agrees to pay Company the non-energy and non-fuel charges of its Retail Transmission Service Standard Rate (Rate RTS) for any power that flows into AMP Meldahl from the Transmission Facilities, as fully described in Exhibit 2, Special Contract for Retail Transmission Service, Contract No. 2014-001084-SCHED, attached hereto;

NOW, THEREFORE, in consideration of the foregoing premises and the respective covenants and agreements of the Participants herein set forth, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, it is mutually agreed as follows:

This Agreement, including the two exhibits, will become effective on the earliest date authorized by law but no later than the date on which power first flows to or from AMP Meldahl across the Transmission Facilities; and,

Company will provide retail electric service to any and all Customer facilities in Company's certified service territory that are not electrically connected to AMP Meldahl at standard tariff rates, terms, and conditions.

IN WITNESS WHEREOF, the names of the parties have been hereunto subscribed by their officers duly authorized thereto as of the day and year first above written.

KENTUCKY UTILITIES COMPANY

By:______________________
John P. Malloy
VP Customer Services

Attest:

By:______________________
Notary - June 21, 2018

400001.125957/1121100.1

AMERICAN MUNICIPAL POWER, INC.

By:______________________
Marc S. Gerken, President/CEO

Attest:

By:______________________
John W. Bentine, Sr. Vice President/General Counsel

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
10/13/2014
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

AMP Contract No. 2014-001083-SCHED

EXHIBIT 1, CONTRACT FOR BACK-UP ELECTRIC SERVICE

This Contract for Back-Up Electric Service ("Back-Up Contract") made and entered into this 9th day of September, 2014, by and between Kentucky Utilities Company ("Company") and American Municipal Power, Inc. ("Customer").

1. Service: Beginning on the date on which power first flows to or from Customer's hydroelectric generating facility in Foster, Kentucky ("AMP Meldahl") across the transmission facilities interconnecting AMP Meldahl with the transmission facilities of Duke Energy, Inc. ("DEO") in Ohio (which facilities are under the operating control of PJM Interconnection, L.L.C.), Company will provide to AMP Meldahl back-up power service to serve its station power in the event that the other AMP Meldahl back-up systems fail.

   All back-up electric capacity and energy taken under this Back-Up Contract will be delivered as 3 phase, 60 cycle, alternating current, at a nominal voltage at the point of 12,470 volts, metered and billed as primary service.

   This point of delivery requires an estimated system capacity of 800 kW, or kVA as is appropriate, of Back-Up Contract capacity.

   It is mutually agreed that Company's general terms and conditions and applicable rate schedules, but not the special terms and conditions, as from time to time approved by and on file with the Kentucky Public Service Commission, are made a part of this Back-Up Contract as fully as if written here unless such term or condition is in express conflict with a term or condition of this Back-Up Contract or Agreement, in which case the term or condition of this Back-Up Contract or Agreement shall prevail. Nothing in this Back-Up Contract prohibits or precludes AMP from challenging any changes proposed by Company or otherwise to Company's tariff that impact AMP or AMP Meldahl.

2. Term: This Back-Up Contract shall be in full force and effect for a period of two years from the commercial operation date, unless otherwise stated in the applicable tariff, and shall continue in force thereafter for successive periods of one year each until either party shall give the other not less than sixty days written notice of its intention to terminate this contract at the expiration of and of said yearly periods. Notwithstanding anything in this Back-Up Contract or Agreement to the contrary, this Back-Up Contract shall automatically terminate upon the proper cancellation by the Kentucky Public Service Commission of any rate or tariff whose administration of the same is necessary for this Back-Up Contract to continue; however, the renaming, restructuring, or changing of rates of any tariff provision this Back-Up Contract addresses shall not constitute cancellation of the same, and shall not automatically terminate this Back-Up Contract.

3. Notice: Customer must give Company at least 30 calendar days' notice of the date on which power first flows to or from AMP Meldahl across the transmission facilities interconnecting AMP Meldahl with DEO's transmission facilities in Ohio.

4. Rate: Each month Customer will pay to Company for all facilities provided, and capacity and energy delivered, to Customer in the preceding billing period an amount determined in accordance with:

    a. Company's Time-of-Day Primary Service Standard Rate (Rate TODP) and

    b. Company's Supplemental or Standby Service Standard Rate Rider (Rider SS)

IN WITNESS WHEREOF, the parties hereto have caused this Back-Up Contract to be executed by their duly authorized representatives this day and year shown above.

KENTUCKY UTILITIES COMPANY

By: ______________________

John P. Malloy
VP Customer Services
Official Capacity

Attest:

By: Betty L. Griel

Notary - June 6, 2018

AMERICAN MUNICIPAL POWER, INC.

By: ______________________

Marc S. Gerken, President/CEO
Official Capacity

Attest:

By: ______________________
John W. Bentine, Sr. Vice President/General Counsel

KENTUCKY
PUBLIC SERVICE COMMISSION

JEFF R. DEROUEN
EXECUTIVE DIRECTOR

TARIFF BRANCH

Bunt Kirtley

EFFECTIVE

10/13/2014

PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

AMP Contract No. 2014-001084-SCHED

EXHIBIT 2, SPECIAL CONTRACT FOR RETAIL ELECTRIC TRANSMISSION SERVICE

This Special Contract for Retail Transmission Service ("Special Contract") made and entered into this 9th day of September, 2014, by and between Kentucky Utilities Company ("Company") and American Municipal Power, Inc. ("Customer").

Company and Customer acknowledge that it would be uneconomical for Company to provide the energy supplied to AMP Meldahl across the transmission facility interconnecting AMP Meldahl with the transmission facilities of Duke Energy Ohio, Inc. ("DEO") (which facilities are under the operating control of PJM Interconnection, L.L.C.). Accordingly, energy will be supplied to Customer by entities other than Company according to the applicable rules, policies, and practices of PJM Interconnection, LLC. Nonetheless, Company and Customer acknowledge Company's exclusive right under Kentucky Revised Statutes 278.018 to provide retail electric service to AMP Meldahl. Therefore, Company and Customer are entering into this arrangement to accommodate the economic reality while protecting Company's exclusive retail service rights under Kentucky Revised Statutes 278.018. Company and Customer acknowledge this is a unique situation, not a template for future projects.

1. Service and Rates:

   a. Back feed for testing and commissioning. Beginning on the date on which power first flows to or from Customer's hydroelectric generating facility in Foster, Kentucky ("AMP Meldahl") across the transmission facilities interconnecting AMP Meldahl with the transmission facilities of DEO in Ohio, Customer will pay Company for retail electric transmission service under the terms of Company's Retail Transmission Service Standard Rate (Rate RTS), with the following exceptions:

      i. Company will not bill Customer, and Customer will not pay Company, for the Energy Charge or Fuel Adjustment Clause charges provided under Rate RTS;

      ii. Company will not bill Customer, and Customer will not pay Company for the Demand-Side Management Cost Recovery Mechanism (Sheet No. 86), which would not apply to Customer in any event because Customer is an industrial customer for the purposes of Company's Demand-Side Management Cost Recovery Mechanism.

      iii. All other provisions of Rate RTS will apply.

2. Consumption Data: To calculate the applicable charges under Rate RTS, Customer will supply to Company within 15 calendar days of the last day of each calendar month the appropriate electric demand and energy consumption data for that month related to AMP Meldahl's gross electric energy consumption from its facilities interconnected with DEO's transmission facilities.

3. Audit and Metering: Customer agrees to permit Company, upon reasonable request, to audit, and will fully cooperate in any Company audit of, the electric demand and energy

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
10/13/2014
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

consumption data Customer has provided to Company. After such audit, Company may reasonably request that additional metering equipment be installed if necessary to ensure accurate measurement of Customer's electric demand and gross electric energy consumption from its transmission facilities interconnected with DEO's transmission facilities. Customer agrees to cooperate with Company and facilitate the installation of such metering equipment as Company in its sole discretion determines to be necessary. Company will bear the cost of any such meter and any related metering equipment. Company will install such metering equipment in consultation with Customer and in such a manner as to minimize any impacts to Customer's operations.

4. Term: This Special Contract shall be in full force and effect for a period of two years from first date on which power first flows to or from AMP Meldahl and shall continue in force thereafter for successive periods of one year each until either party shall give the other not less than sixty days written notice of its intention to terminate this Special Contract at the expiration of and of said yearly periods. Notwithstanding anything in this Special Contract to the contrary, this Special Contract shall automatically terminate upon the proper cancellation by the Kentucky Public Service Commission of any rate or tariff whose administration of the same is necessary for this Special Contract to continue; however, the renaming, restructuring, or changing of rates of any tariff provision this Special Contract addresses shall not constitute cancellation of the same, and shall not automatically terminate this Special Contract.

5. Tariff Provisions: It is mutually agreed that Company's general terms and conditions and applicable rate schedules as from time to time approved by and on file with the Kentucky Public Service Commission, are made a part of this Special Contract as fully as if written here unless such term or condition is in express conflict with a term or condition of this Special Contract, in which case the term or condition of this Special Contract shall prevail. Nothing in this Special Contract prohibits or precludes AMP from challenging any changes proposed by Company or otherwise to Company's tariff that impact AMP or AMP Meldahl.

IN WITNESS WHEREOF, the parties hereto have caused this Contract to be executed by their duly authorized representatives this day and year shown above.

KENTUCKY UTILITIES COMPANY

By: John P. Malloy

VP Customer Services
Official Capacity

Attest:

By: Dotty L. Triley

Notary - June 21, 2018

AMERICAN MUNICIPAL POWER, INC.

By:

Marc S. Gerken, President/CEO
Official Capacity

Attest:

By:
John W. Bentine, Sr. General Counsel

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
10/13/2014
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 2

Responding Witness: Paul W. Thompson / John P. Malloy

Q-2. Refer to the Application, page 8, paragraph 14; and the Direct Testimony of Victor A. Staffieri ("Staffieri Testimony"), page 2, lines 7-8; and the Direct Testimony of Paul W. Thompson ("Thompson Testimony"}, page 22, lines 10-11. The Application states that KU will replace a total of 530,000 meters in its territory. The Staffieri Testimony states that KU serves 546,000 customers while the Thompson Testimony states that KU serves approximately 519,000 customers.

a. Explain the discrepancy in the number of customers served as stated in the testimonies.

b. Reconcile the number of meters being replaced as stated in the Application with the number of customers served by KU as stated in the testimonies.

A-2.

a. The 546,000 number in Mr. Staffieri's testimony was taken from general Company information earlier in 2016 and included approximately 28,000 KU Virginia customers, leaving the KU Kentucky customer count at 518,000. The 519,000 customers was based on the Company's operating reports at August 31, 2016 for KU Kentucky customers only. The difference of approximately 1,000 customers was due to slightly different points in time of when the customer count information was taken.

b. The Companies plan to replace all electric meters except for the MV90 meters (approximately 3,800 meters) with AMS meters. The difference between number of customers served by KU and numbers of meters is because some customers have more than one meter.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 3

Responding Witness: John P. Malloy

Q-3. Refer to the Application, page 16, paragraph 36. The last sentence of the paragraph states, "[a]ccordingly, KU requests a permanent deviation from 807 KAR 5:006, Section 14(3) for its AMS meters that allow for remote data communication." State whether there are Advanced Metering System ("AMS") meters that do not allow for remote data communication. If so, explain.

A-3. All AMS meters allow for remote data communication.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 4

Responding Witness: Robert M. Conroy / William S. Seelye

Q-4. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet Nos. 35 and 35.1, Lighting Service. State whether KU considered decreasing the rate for each of the following lights that exceed the cost support provided in the Direct Testimony of William Steven Seelye ("Seelye Testimony"), Exhibit WSS-4: 464, 465, 488, 451, 491, 492, 497, 498, and 499. If not, explain.

A-4. Yes, the Company considered reducing the charges for the referenced light codes but decided against proposing decreases to these lights because reductions for these rates would have resulted in larger increases to other lights, especially lights whose rates are significantly below current actual costs. This is the reverse side of capping the maximum increase for any light at 30% and is consistent with the ratemaking principle of gradualism. Bringing all rates to a cost-based level, especially by lowering the rates for light codes 464, 465, 488, 451, 491, 492, 497, 498, and 499, would have necessitated increasing the 30% cap used to limit the maximum increase to any one rate.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 5

Responding Witness: Robert M. Conroy / William S. Seelye

Q-5. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet Nos. 36, 36.1 and 36.2, Restricted Lighting Service. State whether KU considered decreasing the rate for each of the following lights that exceed the cost support provided in the Exhibit WSS-4: 455, 490, 493, and 360.

A-5. Yes, the Company considered reducing the charges for the referenced light codes but decided against proposing decreases to these lights because reductions for these rates would have resulted in larger increases to other lights, especially lights whose rates are significantly below current actual costs. See the response to Question No. 4.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 6

Responding Witness: Robert M. Conroy / William S. Seelye

Q-6. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet No. 36.1. Explain why KU is proposing to eliminate light 434, whether there are any customers with this light, and if so, the effect the elimination will have on those customers.

A-6. Bill code 434 is an incandescent "tear drop" fixture. There are no customers presently on this rate. The Company does not want to encourage future customers to be on this rate due to the lack of available incandescent products and due to the newer lighting technologies that exist today.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information Dated January 11, 2017

Question No. 7

Responding Witness: William S. Seelye

Q-7. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet No. 41. Provide supporting calculations for the increase in the rates for EVSE, Electric Vehicle Supply Equipment, shown on this page.

A-7. See attached.

Certain information requested is confidential and proprietary and is being filed under seal pursuant to a Petition for Confidential Protection.

KENTUCKY UTILITIES COMPANY

DERIVATION OF RATES FOR EVSE

NEW EVSE / EVC TARIFF

CONFIDENTIAL INFORMATION REDACTED

			LEVEL 2 Single Charger EVSE(R) & EVSE	LEVEL 2 Single Charger EVC	LEVEL 2 Dual Charger EVSE(R) & EVSE
Estimated Investment per Unit			[redacted]	[redacted]	[redacted]
Fixed Charges @	**22.27%**		[redacted]	[redacted]	[redacted]
O&M (scheduled/trouble)			[redacted]	[redacted]	[redacted]
Energy Management Fee (5 years)			[redacted]	[redacted]	[redacted]
Networking Service Plan (5 years)			[redacted]	[redacted]	[redacted]
			$1,598.12	$4,521.68	$2,481.76
EVSE Monthly Rate for Equipment Only		EVSE (R)	**$133.18**		**$206.81**
EVC Monthly Rate for Equipment Only			$376.81		$450.44
EVSE Rate per Hour for Equipment Only				$2.48	
Distribution Energy per kWh per year (Calculated with GS Rate)	**0.10685**		$625.29		$1,250.57
Distribution Energy per kWh per month			$52.11		$104.21
Distribution Energy per kWh per hour				$0.4283	
Basic Service Charge			$0.00	$0.00	$0.00
Fuel Adjustment Clause			$0.00	-$0.01977	$0.00
Environmental Surcharge (Level 2)			$0.00	$0.02	$0.00
Franchise Fee			$0.00	$0.00	$0.00
School Tax			$0.00	$0.00	$0.00
State Sales Tax			$0.00	$0.00	$0.00
EVSE Monthly Rate for Equipment, Energy & Factors		EVSE	**$185.28**		**$311.03**
EVC Fee per Hour for Equipment, Energy & Factors		EVC		**$2.90**	

KU

EVC Capital

MONTH	DAYS / MONTH	Single Charger		Dual Charger	
		Daily Capital	Monthly Capital	Daily Capital	Monthly Capital
JAN	31	$12.16	$376.81	$14.53	$450.44
FEB	28	$13.46	$376.81	$16.09	$450.44
MAR	31	$12.16	$376.81	$14.53	$450.44
APR	30	$12.56	$376.81	$15.01	$450.44
MAY	31	$12.16	$376.81	$14.53	$450.44
JUN	30	$12.56	$376.81	$15.01	$450.44
JUL	31	$12.16	$376.81	$14.53	$450.44
AUG	31	$12.16	$376.81	$14.53	$450.44
SEP	30	$12.56	$376.81	$15.01	$450.44
OCT	31	$12.16	$376.81	$14.53	$450.44
NOV	30	$12.56	$376.81	$15.01	$450.44
DEC	31	$12.16	$376.81	$14.53	$450.44
	365	$12.40	$4,521.68	$14.82	$5,405.32
		Daily Average		Daily Average	

Capital:	**$**	**9.90**	Daily Weighted Average
	$	**2.48**	Rate per Hour

Energy Calculation:

$0.4283	kWh charge per hour =	(kWh per year x energy rate) / 365 days per year / 4 hours per day

Kentucky Utilities Company
Support for EVSE, EVC and EVSE-R Rates
Case No. 2016-00370

KU	**Fuel Adjustment Clause**		Fuel Base:	**0.02892**	
					kWh
					Per hour
		2016			**4.01**
	November		-0.00475		
	October		-0.00428		
	September		-0.00256		
	August		-0.00348		
	July		-0.00645		
	June		-0.00605		
	May		-0.0068		
	April		-0.00417		
	March		-0.00186		
	February		-0.00622		
	January		-0.00586		
	December	'2015	-0.00671		
		Average	**-0.00493**		**-0.01977** FAC per hour

KU	**Environmental Surcharge**			
		2016	Group 1	Group 2
	November		1.55%	2.33%
	October		1.73%	2.59%
	September		1.84%	2.77%
	August		2.32%	3.54%
	July		3.28%	5.07%
	June		3.44%	5.37%
	May		2.77%	4.37%
	April		1.51%	2.42%
	March		5.64%	9.13%
	February		6.13%	10.05%
	January		6.09%	10.08%
		2015	6.06%	10.07%
		Average	**3.53%**	**5.65%**

Kentucky Utilities Company
Support for EVSE, EVC and EVSE-R Rates
Case No. 2016-00370

KU

Weighted Average Cost of Capital (WACC)

	Capitalization Ratio	Annual R.O.E.	Annual Cost	Weighted Cost
Common	53.27%	10.23%		5.450%
Total Equity	53.27%			
Short Term	2.46%		0.74%	0.018%
Long Term	44.26%		4.12%	1.824%
Total Debt	46.72%			
Total WACC	100.00%			**7.291%**

Overall Cost of Capital

Carrying Charge Income Tax Calculation

Corporate Tax Rate: 38.90%

Carrying Charge: (Weighted Cost of Equity / (1- CORPORATE TAX RATE)) x CORPORATE TAX RATE

(**5.450%** / (**1** - **38.90%**)) x **38.90%**

3.469%

Calculation of Annual Carrying Charge

Overall Rate of Return	7.291%
Straight Line Depreciation	
10 year useful life	10%
Income Taxes	3.469%
Property Tax	1.514%
TOTAL LEVELIZED FIXED CHARGE	**22.27%**

Kentucky Utilities Company
Support for EVSE, EVC and EVSE-R Rates
Case No. 2016-00370

Charging Station Consumption

KU		kWh / DAY	(HRS/MO. X KW)	
MONTH	**DAYS / MONTH**	**16**	**kWh / MONTH**	
JAN	31		496	
FEB	28		448	
MAR	31		496	
APR	30		480	
MAY	31		496	
JUN	30		480	
JUL	31		496	
AUG	31		496	
SEP	30		480	
OCT	31		496	
NOV	30		480	
DEC	31		496	
	365	=HRS/YEAR	**5,852**	=kWh / YEAR *

* Includes additional 1 kWh / month for display & security lighting

KU
CAPITAL INVESTMENT
CONFIDENTIAL INFORMATION REDACTED

		Level 2 Charger		**Level 2 Charger**	
Installed Cost for		***Single***		***Dual***	
Electric Vehicle Charging Station		**Material**	**Labor**	**Material**	**Labor**
Charging Station (Bollard Charger)		[redacted]		[redacted]	
Sales Tax		[redacted]		[redacted]	
Shipping cost		[redacted]		[redacted]	
Install Cost (materials / labor) **EVC Only**		$1,120.00	$12,005.00	$1,120.00	$12,005.00
	Subtotal:	[redacted]	$12,005.00	[redacted]	$12,005.00
	Overheads	$0.00	$0.00	$0.00	$0.00
	Total with OH	[redacted]	$12,005.00	[redacted]	$12,005.00
Total Cost (1 year)		**$17,702.48**		**$19,638.04**	

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 8

Responding Witness: William S. Seelye

Q-8. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet No. 42. Provide supporting calculations for the increase in the Electric Vehicle Charging rate.

A-8. See the response to Question No. 7.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 9

Responding Witness: William S. Seelye

Q-9. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet No. 75. Provide supporting calculations for the increase in the rates for EVSE-R, Electric Vehicle Supply Equipment, shown on this page.

A-9. See the response to Question No. 7.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 10

Responding Witness: Robert M. Conroy

Q-10. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet No. 86.1 0, Demand-Side Management Cost Recovery Mechanism. State whether the current rates will change as a result of new base rates. If so, explain how they will change.

A-10. The DSM Revenue from Lost Sales component of the Demand-Side Management Cost Recovery Mechanism will go to zero upon approval and implementation of new base rates. Revised Demand-Side Management Cost Recovery components will be filed for Commission approval based on the effective date of new base rates in this proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 11

Responding Witness: Robert M. Conroy

Q-11. Refer to Tab 5 of the Application, proposed P.S.C. No. 18, Original Sheet No. 97, Application for Service section, first paragraph. Outside of the date of birth requirement as discussed on page 31 of the Direct Testimony of Robert M. Conroy ("Conroy Testimony"), explain whether the changes to this paragraph represent a change from KU's current practice. If so, identify the changes and explain the reason for each change.

A-11. The changes do not represent a change from KU's current practice. The changes merely provide more detail in the tariff reflecting KU's current practices with respect to application information.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 12

Responding Witness: Kent W. Blake

Q-12. Refer to Tab 16 of the Application, A. Page 7 of 18, which states that rate case revenue requirements impacts are calculated using expected Return on Equity ("ROE") based on past rate case settlements. Provide the ROE used for each year of the 2017 business plan.

A-12. The financial forecasts provided in this proceeding do not include assumptions for projected rate case activity or ROE changes. However, the Company's 2017 business plan did assume no change to approved ROEs on other rate mechanisms and a 10% ROE on base rates for 2017, 2018 and a portion of 2019. From that point forward, the 2017 business plan assumed an ROE of 10.25%. Subsequent to the development of this assumption in the 2017 Business Plan, the Company received the testimony of Mr. McKenzie. The economic analysis presented by Mr. McKenzie demonstrates that a 10.23 return on common equity was reasonable under current economic conditions at the time his analysis was prepared based on established methods for developing the cost of equity capital.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 13

Responding Witness: Christopher M. Garrett / William S. Seelye

Q-13. Refer to Tab 67 of the Application, Typical Bill Comparison Under Present and Proposed Rates.

a. Refer to page 4 of 22. Provide the largest rate impact the proposed changes to this rate class will have on a single customer taking service under All Electric School Single-Phase.

b. Refer to page 5 of 22. Provide the largest rate impact the proposed changes to this rate class will have on a single customer taking service under All Electric School Three-Phase.

c. Refer to page 14 of 22 and to P.S.C. No. 18, Original Sheet No. 30. Explain the basis for the proposed changes to the Fluctuating Load Service Primary rates.

A-13.

a. The largest impact on a single customer taking service under All Electric School Single-Phase is $75.49 (7.6%) per month based on historical usage for the period of September 2015 through August 2016.

b. The largest impact on a single customer taking service under All Electric School Three-Phase is $589.80 (1.9%) per month based on historical usage for the period of September 2015 through August 2016.

c. There are currently no customers taking service under the Fluctuating Load Service Primary rate. The charges were designed to be revenue neutral with Rate TODP based on the relationship between the billing demands determined on the basis of 15-minute demand readings for Rate TODP versus the 5-minute demand readings for Rate FLS, as set forth in the Determination of Maximum Load section of the Rate FLS tariff.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 14

Responding Witness: David S. Sinclair / Daniel K. Arbough

Q-14. Refer to Filing Requirement - 807 KAR 5:001, Section 16(8){d} ("FR 16.8.d"), Schedule D-1 , page 1 of 8.

a. Refer to line 4, Commercial Sales of Electricity. The description of the ($2, 145,637) adjustment from the base period to the forecasted test period reads, "Variance reflects forecasted decrease in billing determinates from the base period to the forecasted period at current tariff rates." Provide the reason(s) for the decrease in the billing determinants and explain how the amount of decrease was determined.

b. Refer to line 7, Other Sales to Public Authorities. The description of the ($962,804) adjustment from the base period to the forecasted test period reads, "Variance reflects forecasted decrease in billing determinates from the base period to the forecasted period at current tariff rates." Provide the reason(s) for the decrease in the billing determinants and explain how the amount of decrease was determined.

c. Refer to line 13, Late Payment Charges. The description of the ($198,073) adjustment from the base period to the forecasted test period reads, "Variance reflects trend in this account and is based on a historic average." Provide supporting work papers, spreadsheets, etc. , which show the derivation of this adjustment, along with any necessary narrative explanation.

d. Refer to line 14, Electric Service Revenues. The description of the ($68,919) adjustment from the base period to the forecasted test period reads, "Variance reflects trend in this account and is based on a historic average." Provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment, along with any necessary narrative explanation.

e. Refer to line 15, Rent from Electric Property. The description of the ($103,511) adjustment from the base period to the forecasted test period reads, "Variance reflects trend in this account and is based on a historic average." Provide supporting workpapers, spreadsheets, etc. which show the derivation of this adjustment along with any necessary narrative explanation.

A-14.

a. The decrease in KU Commercial billing determinants is primarily due to lower projected demand volumes for these customers as described in the direct testimony of David Sinclair and lower projected fuel revenues. The table below indicates how the decrease was determined. It highlights the lower demand revenues due to a drop in KU demand customer volumes and lower base fuel revenues due to lower projected fuel cost.

	A	B	
	Base Period - YE Feb 2017	Forecasted Test Period - YE June 2018	B - A
	Base Rev (included base fuel)		
Commercial			
Stats:			
Customer Count	79,972	79,568	(404)
Energy Forecast (MWh)	3,886,507	3,870,488	(16,019)
Demand Forecast (MVA/MW)	10,335	10,140	(195)
Total Revenues:			
Total Customer Revenue	29,907,760	29,913,620	5,860
Base Energy Revenue	122,860,484	122,928,131	67,647
Total Demand Revenue	87,872,461	86,116,128	(1,756,333)
Total Base Fuel Revenue	112,397,317	111,934,506	(462,811)
Total Revenues	353,038,022	350,892,385	(2,145,637)

b. The decrease in KU Other Sales to Public Authorities billing determinants is primarily due to lower projected demand volumes and lower projected fuel revenues. Demand volumes are heavily influenced by energy sales and the energy forecast is driven by increased efficiencies offsetting a small amount of customer growth. A discussion of factors influencing the load forecast is included on pages 4-7 in the direct testimony of David S. Sinclair as well as in the Filing Requirement 16(7)(c) Item B and Item C attached at Tab 16 of the Companies' Applications. The table below indicates how the decrease was determined. Lower demand revenues and lower projected fuel cost lead to an overall decline in projected revenues.

	A	B	
	Base Period - YE Feb 2017	Forecasted Test Period - YE June 2018	B - A
	Base Rev (included base fuel)		
KU-KY Public Authority			
Stats:			
Customer Count	7,829	8,047	218
Energy Forecast (MWh)	1,548,787	1,534,039	(14,747)
Demand Forecast (MVA/MW)	7,635	7,492	(143)
Total Revenues:			
Total Customer Revenue	3,895,553	3,841,015	(54,538)
Base Energy Revenue	25,514,488	25,745,533	231,045
Total Demand Revenue	44,422,277	43,709,606	(712,671)
Total Base Fuel Revenue	44,791,056	44,364,416	(426,640)
Total Revenues	118,623,374	117,660,570	(962,804)

c. See attached.

d. See attached.

e. See attached.

Purpose - to tie amounts in budget to Schedule D-1

Late Payment Fees: Base Period YE February 2017:	MAR-2016	APR-2016	MAY-2016	Jun-16	JUL-2016	AUG-2016	SEP-2016	OCT-2016	NOV-2016	DEC-2016	JAN-2017	FEB-2017	**Base Period**
450-LATE PAYMENT CHARGES	$481,050	$281,520	$211,069	$243,426	$340,924	$495,952	$373,010	$373,010	$373,010	$373,010	$330,090	$330,090	**$4,206,160**
450-LATE PAYMENT CHARGES MUNI	$10	$0	$0	$0	$0	$0	$13	$13	$13	$13	$9	$9	**$83**
TOTAL LATE PAYMENT CHARGES	$481,060	$281,520	$211,069	$243,426	$340,924	$495,952	$373,023	$373,023	$373,023	$373,023	$330,100	$330,100	**$4,206,243**
Jurisdictional factor - Per Schedule C-2.1B													96.42%
Base Amount which agrees to Schedule D-1													**$4,055,578**

Late Payment Fees: Forecasted Test Period YE June 2018:	JUL-2017	AUG-2017	SEP-2017	OCT-2017	NOV-2017	DEC-2017	JAN-2018	FEB-2018	MAR-2018	APR-2018	MAY-2018	JUN-2018	**Forecasted Period**
450-LATE PAYMENT CHARGES	$330,090	$330,090	$330,090	$330,090	$330,090	$330,090	$336,692	$336,692	$336,692	$336,692	$336,692	$336,692	**$4,000,696**
450-LATE PAYMENT CHARGES MUNI	$9	$9	$9	$9	$9	$9	$10	$10	$10	$10	$10	$10	**$115**
TOTAL LATE PAYMENT CHARGES	$330,100	$330,100	$330,100	$330,100	$330,100	$330,100	$336,702	$336,702	$336,702	$336,702	$336,702	$336,702	**$4,000,811**
Jurisdictional factor - Per Schedule C-2.1F													96.42%
Forecasted Amount which agrees to Schedule D-1													**$3,857,505**
Base *Less* Forecast Test Period per Schedule D-1													**$198,073**

Electric Service Revenues: Base Period YE February 2017:	MAR-2016	APR-2016	MAY-2016	Jun-16	JUL-2016	AUG-2016	SEP-2016	OCT-2016	NOV-2016	DEC-2016	JAN-2017	FEB-2017	**Base Period**
451-RECONNECT CHARGES	$206,024	$251,426	$197,064	$173,404	$134,036	$213,318	$176,488	$176,488	$176,488	$176,488	$178,776	$178,776	**$2,238,777**
451-OTHER SERVICE CHARGES	$4,397	$5,120	$6,573	$4,503	$3,985	$5,591	$4,669	$4,669	$4,669	$4,669	$4,751	$4,751	**$58,345**
TOTAL ELECTRIC SERVICE REVENUES	$210,421	$256,546	$203,637	$177,907	$138,021	$218,909	$181,157	$181,157	$181,157	$181,157	$183,527	$183,527	**$2,297,122**
Jurisdictional factor - Per Schedule C-2.1B													94.78%
Base Amount which agrees to Schedule D-1													**$2,177,201**

Electric Service Revenues: Forecasted Test Period YE June 2018:	JUL-2017	AUG-2017	SEP-2017	OCT-2017	NOV-2017	DEC-2017	JAN-2018	FEB-2018	MAR-2018	APR-2018	MAY-2018	JUN-2018	**Forecasted Period**
451-RECONNECT CHARGES	$178,776	$178,776	$178,776	$178,776	$178,776	$178,776	$182,352	$182,352	$182,352	$182,352	$182,352	$182,352	**$2,166,769**
451-OTHER SERVICE CHARGES	$4,751	$4,751	$4,751	$4,751	$4,751	$4,751	$4,846	$4,846	$4,846	$4,846	$4,846	$4,846	**$57,581**
TOTAL ELECTRIC SERVICE REVENUES	$183,527	$183,527	$183,527	$183,527	$183,527	$183,527	$187,198	$187,198	$187,198	$187,198	$187,198	$187,198	**$2,224,350**
Jurisdictional factor - Per Schedule C-2.1F													94.78%
Forecasted Amount which agrees to Schedule D-1													**$2,108,282**
Base *Less* Forecast Test Period per Schedule D-1													**$68,919**

Rent from Electric Property: Base Period YE February 2017:	MAR-2016	APR-2016	MAY-2016	Jun-16	JUL-2016	AUG-2016	SEP-2016	OCT-2016	NOV-2016	DEC-2016	JAN-2017	FEB-2017	**Base Period**
454-RENT FROM ELEC PROPERTY	$286,889	$263,433	$288,060	$280,581	$101,957	$263,383	$286,884	$286,884	$286,884	$286,884	$284,452	$253,764	**$3,170,055**
454-RENT FROM ELEC PROPERTY I/C	$34,982	$21,101	$20,843	$20,843	$20,844	$20,845	$31,878	$31,878	$31,878	$31,878	$21,292	$21,292	**$309,554**
TOTAL RENT FROM ELECTRIC PROPERTY	$321,872	$284,534	$308,903	$301,424	$122,801	$284,228	$318,762	$318,762	$318,762	$318,762	$305,744	$275,056	**$3,479,610**
Departing Municipal facility charge already reflected in account 456 [1]						-$230	-$230	-$230	-$230	-$230			**-$1,151**
Amount per Schedule C-2.1B Unadjusted Total Company													**$3,478,458**
Jurisdictional factor - Per Schedule C-2.1B													**93.32%**
Base Amount which agrees to Schedule D-1													**$3,246,156**

Rent from Electric Property: Forecasted Test Period YE June 2018:	JUL-2017	AUG-2017	SEP-2017	OCT-2017	NOV-2017	DEC-2017	JAN-2018	FEB-2018	MAR-2018	APR-2018	MAY-2018	JUN-2018	**Forecasted Period**
454-RENT FROM ELEC PROPERTY	$254,101	$254,101	$254,101	$254,101	$254,101	$254,101	$289,860	$259,171	$259,171	$259,171	$259,171	$259,171	**$3,110,319**
454-RENT FROM ELEC PROPERTY I/C	$21,292	$21,292	$21,292	$21,292	$21,292	$21,292	$21,578	$21,578	$21,578	$21,578	$21,578	$21,578	**$257,220**
TOTAL RENT FROM ELECTRIC PROPERTY	$275,393	$275,393	$275,393	$275,393	$275,393	$275,393	$311,438	$280,749	$280,749	$280,749	$280,749	$280,749	**$3,367,539**
Jurisdictional factor - Per Schedule C-2.1F													93.32%
Forecasted Amount which agrees to Schedule D-1													**$3,142,645**
Base *Less* Forecast Test Period per Schedule D-1													**$103,511**

Notes:

March 2016 to August 2016 based on actuals per trial balance.

September 2016 to December 2016 based on previous budget

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 15

Responding Witness: Lonnie E. Bellar

Q-15. Refer to FR 16.8.d, Schedule D-1, page 2 of 8, line 24, Steam Expenses. The description of the $626,149 adjustment from the base period to the forecasted test period reads, "Base period understated for limestone for Trimble County 2 that should have been allocated to KU." Confirm that this cost was originally allocated to Louisville Gas and Electric Company ("LG&E") ("collectively Companies") and that it made a corresponding adjustment to its base year to correct the misallocation.

A-15. The costs for limestone used at the Trimble County 2 plant for the months September through December 2016 in the base period were misallocated only to LG&E. This resulted in the KU base year being understated. A corresponding adjustment was made on LG&E reflecting the misallocation and thus LG&E being overstated in the base period. The forecasted test years for both utilities are correctly allocated.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 16

Responding Witness: Lonnie E. Bellar

Q-16. Refer to FR 16.8.d, Schedule D-1, page 2 of 8, line 26. Also refer to the Direct Testimony of Daniel K. Arbough ("Arbough Testimony") at page 5, which states that, "The resulting change in average wage rates between the previous test year ending June 30, 2016 and the forecasted test year ending June 30, 2018 is 3.6% over a two-year period, or 1.8% on an average annual basis." The description of the $435,956 adjustment from the base period to the forecasted test period reads, "Labor increases for Trimble County 2." The adjustment represents an approximate 6.4 percent increase in labor expenses at Trimble 2. Explain why this increase in labor expense is so much larger than the average wage increase discussed in the Arbough Testimony.

A-16. Upon further review, the increase in labor at Trimble County 2 is minimal with total Kentucky Utilities labor for this account increasing approximately $158,000 or 2.8%. The remaining increase is primarily due to the increase in chemicals for circulating water equipment at the Ghent plant. This increase is driven mainly by a need for acid injection chemicals on Units 1 and 2 to reduce service water intake to comply with environmental regulations.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 17

Responding Witness: Lonnie E. Bellar

Q-17. Refer to FA 16.8.d, Schedule D-1, page 2 of 8, line 27, Misc Steam Power Expenses. The description of the $1,152,865 adjustment from the base period to the forecasted test period reads, "Base period understated for ammonia, hydrated lime and mercury mitigation agents for Trimble County 2 that should have been allocated to KU." Confirm that this cost was originally allocated to LG&E and that LG&E made a corresponding adjustment to its base year to correct the misallocation.

A-17. The costs for ammonia, hydrated lime and mercury mitigation agents used at the Trimble County 2 plant for the months September through December 2016 in the base period were misallocated only to LG&E. A corresponding adjustment was made on LG&E reflecting the misallocation and thus LG&E being overstated in the base period. The forecasted test years for both utilities are correctly allocated.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 18

Responding Witness: Lonnie E. Bellar

Q-18. Refer to FA 16.8.d, Schedule D-1, page 2 of 8, line 30, Maintenance Supervision and Engineering. The description of the $1,757,375 adjustment from the base period to the forecasted test period reads, "Forecasted test year labor for Trimble County budgeted to FERC 510 instead of FERC 511." Explain why the proposed adjustment is not reflected as a negative adjustment due to the forecasted test year labor cost is being overstated in this account. Also, provide supporting work papers, spreadsheets, etc., which· show the derivation of this adjustment along with any necessary narrative explanation.

A-18. The base period on line 31 correctly states the allocation of Trimble County Unit 2 costs between Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU). However, the allocation to KU in the test year related to FERC Account 511 was incorrectly forecasted to FERC 510, thus overstating the charges in FERC 510. The adjustment is therefore positive due to the test year being higher than the base year for this FERC account. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 19

Responding Witness: Lonnie E. Bellar

Q-19. Refer to FR 16.8.d, Schedule D-1, page 2 of 8, line 31, Maintenance of Structures. The description of the ($1,369,345) adjustment from the base period to the forecasted test period reads, "Forecasted test period labor for Trimble County budgeted to FERC 510 instead of FERC 511." Explain why the proposed adjustment is not reflected as a positive adjustment due to the forecasted test year labor cost is being understated in this account. Also, provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment along with any necessary narrative explanation.

A-19. The base period on line 31 correctly states the allocation of Trimble County Unit 2 costs between Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU). However, the allocation to KU in the test year related to FERC Account 511 was incorrectly forecasted to FERC 510, thus understating the charges in FERC 511. The adjustment is therefore negative due to the test year being lower than the base year for this FERC account. See the supporting spreadsheet attached to response to Question No. 18.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 20

Responding Witness: Lonnie E. Bellar

Q-20. Refer to FR 16.8.d, Schedule D-1, page 2 of 8, line 32, Maintenance of Boiler Plant. The description of the $5.542 million adjustment from the base period to the forecasted test period reads, "Major planned generator overhauls in forecasted test period for Trimble County unit 2 and EW Brown Units."

a. Provide the year(s) in which the most recent generator overhauls were performed on Trimble County unit 2 and the E.W. Brown units.

b. Provide the existing cycles for generator overhauls of Trimble County unit 2 and the E.W. Brown units.

c. State in what year(s) generator overhauls will be planned for Trimble County unit 2 and the E.W. Brown units after the test period.

d. Provide the projected cost of the overhaul at each unit.

e. Explain whether there will be similar overhauls on other units during the base period. If there are such overhauls, identify the unit(s) and provide the actual or projected cost thereof.

A-20.

a. Trimble County unit 2 went in service in 2010; therefore, this is its first major overhaul.

Unit	Year
EW Brown Unit 1	2015
EW Brown Unit 2	2009
EW Brown Unit 3	2012
Trimble County Unit 2	NA

b.

Unit	Year
EW Brown Unit 1	2022
EW Brown Unit 2	2018
EW Brown Unit 2	2025
EW Brown Unit 3	2020
Trimble County Unit 2	2018
Trimble County Unit 2	2026

c. See response to Item b above.

d. The costs reflected in the table below represent maintenance costs for planned and scheduled routine and major overhauls requiring a unit outage. These costs are not jurisdictionalized and do not include costs related to daily maintenance activities included in this account.

	Base $	Test $
EW Brown Unit 1	455,632	608,000
EW Brown Unit 2	595,497	1,794,000
EW Brown Unit 3	855,328	1,208,000
Trimble County Unit 2	1,181,241	4,700,000

e. There will be similar overhauls on other units during the base and test periods. These costs are not jurisdictionalized and do not include costs related to daily maintenance activities included in this account. Costs related to Ghent Unit 4 are outside of the test period.

	Base $	Test $	Type of overhaul
Ghent Unit 1	1,503,553	2,433,000	Routine maintenance/inspections
Ghent Unit 2	2,249,992	2,482,000	Routine maintenance/inspections
Ghent Unit 3	2,298,142	1,358,000	Routine maintenance/inspections
Ghent Unit 4	2,251,261	-	Routine maintenance/inspections

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 21

Responding Witness: Lonnie E. Bellar

Q-21. Refer to FR 16.8.d, Schedule D-1, page 2 of 8, line 33, Maintenance of Electric Plant. The description of the $500,325 adjustment from the base period to the forecasted test period reads, "Major planned turbine overhauls in forecasted period for EW Brown units."

a. Provide the year(s) in which the most recent turbine overhauls were performed on the E.W. Brown units.

b. Provide the existing cycles for turbine overhauls of the E.W. Brown units.

c. State in what year(s) turbine overhauls will be planned for the E.W. Brown units after the test period

d. Provide the projected cost of the overhaul at each unit.

e. Explain whether there will be similar overhauls on other units during the base period. If there are such overhauls, identify the unit(s) and provide the actual or projected cost thereof.

A-21.

a.

Unit	Year
EW Brown Unit 1	2015
EW Brown Unit 2	2009
EW Brown Unit 3	2012

b.

Unit	Year
EW Brown Unit 1	2022
EW Brown Unit 2	2018
EW Brown Unit 2	2025
EW Brown Unit 3	2020

c. See response to item b above.

d. The costs reflected in the table below represent maintenance costs for planned and scheduled routine and major overhauls requiring a unit outage. These costs are not jurisdictionalized and do not include costs related to daily maintenance activities included in this account.

	Base $	Test $
EW Brown Unit 1	817,591	0
EW Brown Unit 2	16,241	3,152,000
EW Brown Unit 3	63,639	0

e. There will be similar overhauls on other units during the base and test periods. These costs are not jurisdictionalized and do not include costs related to daily maintenance activities included in this account.

	Base $	Test $	Type of overhaul
Ghent Unit 1	552,187	115,000	Routine maintenance/inspections
Ghent Unit 2	85,597	1,130,000	Routine maintenance/inspections
Ghent Unit 3	531,825	145,000	Routine maintenance/inspections
Ghent Unit 4	381,705	-	Routine maintenance/inspections
Trimble County Unit 2	909,315	548,000	Routine maintenance/inspections

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 22

Responding Witness: Lonnie E. Bellar

Q-22. Refer to FR 16.8.d, Schedule D-1, page 3 of 8, line 52, Generation Expenses. The description of the $228,970 adjustment from the base period to the forecasted test period reads, "Minor consumables (grease, oil, etc.) small tools and equipment analysis needed for operation of Cane Run 7." Explain why an approximate 60 percent increase in this cost is necessary over this period of time.

A-22. Cane Run 7 (CR7) went into commercial operation in June 2015, with a two year warranty period in the base period. Estimated future maintenance expenses beyond expiration of the warranty were included in the forecasted test period. The initial maintenance cost estimates were adjusted to reflect 18 months of unit operating experience.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 23

Responding Witness: Lonnie E. Bellar

Q-23. Refer to FR 16.8.d, Schedule D-1, page 3 of 8, line 56, Maintenance of Structures. The description of the $1,001,478 adjustment from the base period to the forecasted test period reads, "Major planned overhaul in forecasted test period for Cane Run 7."

a. Explain the need for the major overhaul of Cane Run 7 in the forecasted test period.

b. Provide the year(s) in which the most recent such overhauls were performed on Cane Run 7.

c. Provide the existing cycle for such overhauls for Cane Run 7.

d. State in what years such overhauls will be planned after the test period.

e. Explain whether there will be similar overhauls on other units during the base period. Identify the unit(s) and provide the actual or projected cost thereof.

A-23.

a. During the test period, Cane Run 7 (CR7) will complete the first Combustor Inspection. Since CR7 is a base load unit, this overhaul is needed every two years and includes a visual inspection of all gas path parts. The test year includes costs to completely disassemble the combustor sections in order to ensure the individual component parts are either capable of being re-installed and operational until the next similar outage, or if they will need to be repaired/replaced. Inspections of this nature are standard for this type of unit across all original equipment manufacturers.

b. Cane Run 7 was placed in service in June 2015; therefore, the first iteration of this type of inspection will take place in 2017.

c. Below is a table of the current cycles of overhauls for CR7. Unlike coal units, this schedule is based on forecasted generation and is flexible depending on demand and fuel prices.

Type	Year
Combustor Inspection (CI)	2017
Hot Gas Path Inspection (includes CI)	2019
Combustor Inspection (CI)	2021
Major Inspection (includes CI)	2023
Combustor Inspection (CI)	2025

d. See response to item c above.

e. There are no similar overhauls on other units during the base period.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 24

Responding Witness: Lonnie E. Bellar

Q-24. Refer to FR 16.8.d, Schedule D-1, page 3 of 8, line 57, Maintenance of Generation and Electric Plant. The description of the $1,131,055 adjustment from the base period to the forecasted test period reads, "Major planned overhaul in forecasted test period for EW Brown Unit 6 and unit 1 0."

a. Explain the need for major planned overhauls of E.W. Brown units 6 and 10 in the forecasted test period.

b. Provide the year(s) in which the most recent such overhauls were performed on E.W. Brown units 6 and 10.

c. Provide the existing cycles for such overhauls for E.W. Brown units 6 and 10.

d. State in what years such overhauls will be planned after the test period.

e. Explain whether there will be similar overhauls on other units during the base period. Identify the unit(s) and provide the actual or projected cost thereof.

A-24.

a. Schedule D-1 line 57 incorrectly references E.W. Brown unit 10 when it is actually unit 11 that has a major planned overhaul. The number of service hours of the units triggers the need for a major planned overhaul of simple cycle combustion turbines. The equipment manufacturer has determined defined service intervals for the units based on parts design and fleet experience. It is standard practice throughout the generation industry to perform the overhauls as they come due. Based on service hours, there is a need for overhauls on units 6 and 11 in 2018.

b. The most recent overhaul on E.W. Brown unit 6 was 2007. This is the first such overhaul on unit 11.

c. The cycles for such overhauls are based on service hours for each unit. It is estimated the cycles will occur approximately every ten years.

d. It is estimated the next such overhauls will most likely occur in 2028.

e. There are no costs included in this account in the base period for similar overhauls on other units.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 25

Responding Witness: Lonnie E. Bellar

Q-25. Refer to FR 16.8.d, Schedule 0-1, page 3 of 8, line 58, Maintenance of Misc Other Power Generation Plant. The description of the $1,004,976 adjustment from the base period to the forecasted test period reads, "Increase in process water treatment maintenance." Identify and describe the reason(s) for the proposed increase to process water maintenance expense and provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment.

A-25. The majority of the costs in this account relate to Cane Run 7 (CR7). When CR7 went into commercial operation in June 2015, the plant construction contractor Bluegrass Power Construction (BPC) was under contract to provide a two year warranty period which would ultimately result in BPC covering a portion of the cost to operate and maintain the unit during base period. Costs included in this account include maintenance of process water systems, annual outages, rotating equipment and various other systems. With less than two years of commercial operations, a robust and proactive maintenance plan continues to be implemented throughout these systems as unit specific experience is gained to drive prudent budgeting. This approach minimalizes potential equipment failures which can cause adverse impacts to unit reliability. With process water systems, annual outages, and rotating equipment all having a vital role in power generation, a focused effort has been taken to ensure adequate funding is available in the test period to cover maintenance in the absence of the BPC warranty. Also included in this account are costs associated with outages and maintenance of processed water systems for the EW Brown simple cycle combustion turbines.

A miscalculation of CR7 allocated costs to Kentucky Utilities in the test year is also included in this account. The offset is primarily included in FERC 553 – Maintenance of Generating and Electric Plant and FERC 551 – Maintenance Supervision and Engineering. See the attachment being provided in Excel format for the details of the costs and details on the miscalculation included in this account.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 26

Responding Witness: Lonnie E. Bellar

Q-26. Refer to FR 16.8.d, Schedule D-1, page 4 of 8, line 70, Overhead Line Expenses. The description of the $393,153 adjustment from the base period to the forecasted test period reads, "Variance primarily due to enhanced wood and steel pole/tower inspection program, as well as higher aerial patrol expense." Describe in detail the enhancements made to the wood and steel pole/tower inspection program and how their cost was determined.

A-26. Comprehensive visual inspections are planned for all transmission wood poles, steel poles, and steel towers on a 12 year cycle. These are aerial inspections focused on identifying defects in poles, wires, and associated line hardware. The Company also plans to evaluate below grade capacity and corrosive activity for steel poles and towers on a 24 year cycle. Costs for these programs were based on actual costs from inspections completed on targeted wood poles, steel poles, and steel towers. The Company is expanding these inspection programs across all applicable transmission lines.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 27

Responding Witness: Lonnie E. Bellar

Q-27. Refer to FR 16.8.d, Schedule D-1, page 5 of 8, line 78, maintenance of Overhead Lines. The description of the $5,026,655 adjustment from the base period to the forecasted test period reads, "Variance is driven by change to 'Cycle' based line clearing, enhanced corrosion prevention, and switch maintenance programs." Provide a breakdown of the adjustment which shows the amount of these three items.

A-27. The Conversion to Cycle based line clearing including the implementation of new programs to address the threat of the Emerald Ash Borer and hazard trees is $3,989,944. Corrosion Prevention is $441,761. Switch Maintenance is $549,430. The balance is for miscellaneous items.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 28

Responding Witness: John P. Malloy

Q-28. Refer to FR 16.8.d, Schedule D-1, page 5 of 8, line 90, Meter Expenses. The description of the $1,344,442 adjustment from the base period to the forecasted test period reads, "Increase is due primarily to Advanced Meter System project expenses associated with removing, shipping, tracking, and testing the existing meters that are being removed." Provide the amount of the adjustment if KU's deviation request to eliminate the requirement to test the meters is granted.

A-28. The Advanced Meter System project expenses were $1,116,003 of the $1,344,442 adjustment. Costs related to the existing meters that would be removed if the deviation is granted are $1,095,550 in the forecasted test period, leaving an adjustment of $20,453 for Advanced Meter System project expenses. If the deviation is granted, the total adjustment from the base period to the forecasted test period would be $248,892.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 29

Responding Witness: John P. Malloy

Q-29. Refer to FR 16.8.d, Schedule D-1, page 6 of 8, line 101, Maintenance of Meters. The description of the $1,371,953 adjustment from the base period to the forecasted test period reads, "Test year includes Advanced Meter System expenses associated with repairs to the customer-owned bases of the meters that are attached to the customer's property." Provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment, along with any necessary narrative explanation.

A-29. See the attachment being provided in Excel format.

The Company expects a small percentage of instances in which a technician arrives on site and finds damage to the customer-owned meter base preventing installation of an AMS meter. In these situations, the Company will offer to repair or replace the meter base at a customer's home or business as needed. This will be done at no additional cost to the customer, provided the customer signs a waiver confirming their understanding that these repairs are on a one-time basis and that the customer is responsible for meter base repairs and maintenance going forward. The customer also has the option to refuse this service, and repair the meter base through a contractor of their choice at their own cost.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 30

Responding Witness: John K. Wolfe

Q-30. Refer to FR 16.8.d, Schedule D-1 , page 6 of 8, line 1 02, Maintenance of Misc Distribution Plant. The description of the $237,656 adjustment from the base period to the forecasted test period reads, "Increase is due to buildings & grounds costs previously charged to 921 and 923, which are budgeted to 598. 2016 YTD August costs were reclassified to 598, but the forecast for the remainder of the year was not adjusted. Storm costs are also higher in the test year." Explain the determination of the increase in storm costs in the test year and provide any supporting documentation.

A-30. See attached.

Storm costs are budgeted based on 10-year average actual costs increased by CPI, by FERC account. The Maintenance of Misc Distribution Plant account 10-year average CPI adjusted cost was $106,572 for total KU. The KY jurisdictionalized forward test year amount was $105,410, which was a $39,259 increase from the base year storm costs in this FERC account.

Kentucky Utilities Company
Case No. 2016-00370

Organization	013085				
			Jurisdictional	Jurisdictional	
Sum of Total Months	**Period**		**Base Year**	**Test Year**	
Bud Description	**Base Year**	**Test Year**	**94.350%**	**94.436%**	**Variance**
KU Minor Strms - 012460	698.36				
KU Major Storm O&M 070816	6,622.80				
KU Major Strm Event - 013085	45,653.78	111,621.00			
KU Minor Strms - 013150	2,724.82				
KU MAJOR STORM O&M 05/07/	2,101.25				
KU Minor Strms - 014260	5,505.72				
KU Major Storm O&M 070616	2,624.42				
Major Storm 070416 - Lex	923.97				
OKM062316	50.30				
KU Minor Strms - 013660	3,206.89				
Grand Total	**70,112.31**	**111,621.00**	**66,150.96**	**105,410.41**	**39,259.44**

Kentucky Utilities Company
Case No. 2016-00370

10Year Average By FERC (CPI ADJUSTED)

Company	FERC	
KU	426	532.18
	580	178,490.40
	583	396,297.43
	584	613.55
	588	59,309.40
	590	58,082.66
	592	104,690.32
	593	2,910,881.94
	594	24,959.73
	595	29,033.97
	596	22.46
	598	106,571.76
	925	5,769.35
	930	717.66
KU Total		**3,875,972.80**
LG&E	562	-
	571	3,353.51
	580	414,882.49
	581	-
	583	772,386.19
	584	-
	588	1,423.36
	590	72,905.29
	593	3,358,057.89
	594	95,014.67
	595	33,295.28
	598	97,067.20
	834	-
	880	5,547.13
	891	5,781.27
	907	-
	925	15,116.32
	930	4,722.81
	935	16,428.87
LG&E Total		**4,895,982.28**
Grand Total		8,771,955.09

Kentucky Utilities Company
Case No. 2016-00370

BP Amounts by FERC (CPI ADJUSTED)

Company	FERC	2017	2018	2019	2020	2021
KU	426	547.86	563.57	579.29	592.76	608.48
	580	183,749.09	189,020.58	194,292.07	198,810.49	204,081.98
	583	407,973.16	419,677.30	431,381.45	441,413.58	453,117.73
	584	631.63	649.75	667.87	683.40	701.52
	588	61,056.78	62,808.41	64,560.04	66,061.43	67,813.06
	590	59,793.89	61,509.29	63,224.69	64,695.03	66,410.43
	592	107,774.71	110,866.60	113,958.50	116,608.70	119,700.60
	593	2,996,642.41	3,082,611.66	3,168,580.91	3,242,268.84	3,328,238.09
	594	25,695.09	26,432.25	27,169.40	27,801.25	28,538.40
	595	29,889.37	30,746.85	31,604.33	32,339.32	33,196.80
	596	23.12	23.78	24.45	25.01	25.68
	598	109,711.58	112,859.04	116,006.50	118,704.33	121,851.79
	925	5,939.32	6,109.71	6,280.10	6,426.15	6,596.54
	930	738.80	760.00	781.20	799.36	820.56
KU Total		3,990,166.80	4,104,638.80	4,219,110.80	4,317,229.65	4,431,701.65
LG&E	562	-	-	-	-	-
	571	3,452.31	3,551.36	3,650.40	3,735.29	3,834.33
	580	427,105.76	439,358.80	451,611.83	462,114.43	474,367.47
	581	-	-	-	-	-
	583	795,142.25	817,953.71	840,765.17	860,317.85	883,129.31
	584	-	-	-	-	-
	588	1,465.29	1,507.33	1,549.36	1,585.40	1,627.43
	590	75,053.23	77,206.40	79,359.56	81,205.13	83,358.30
	593	3,456,993.06	3,556,169.09	3,655,345.12	3,740,353.15	3,839,529.18
	594	97,813.99	100,620.13	103,426.27	105,831.53	108,637.67
	595	34,276.23	35,259.56	36,242.89	37,085.75	38,069.09
	598	99,927.00	102,793.76	105,660.52	108,117.74	110,984.50
	834	-	-	-	-	-
	880	5,710.56	5,874.38	6,038.21	6,178.64	6,342.46
	891	5,951.60	6,122.34	6,293.09	6,439.44	6,610.18
	907	-	-	-	-	-
	925	15,561.68	16,008.12	16,454.57	16,837.23	17,283.67
	930	4,861.95	5,001.43	5,140.92	5,260.47	5,399.95
	935	16,912.90	17,398.10	17,883.31	18,299.20	18,784.41
LG&E Total		5,040,227.82	5,184,824.52	5,329,421.22	5,453,361.25	5,597,957.95
Grand Total		9,030,394.62	9,289,463.32	9,548,532.02	9,770,590.90	10,029,659.60

CPI ADJUSTMENT TO ESCALATE FOR BP	
2021	1.1434
2020	1.1138
2019	1.0885
2018	1.0590
2017	1.0295
2016	1.0084

Kentucky Utilities Company
Case No. 2016-00370

Monthly Amounts for Budget Entry

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	2017												
10yr monthly avg	0.085829392	0.145008982	0.075802634	0.103345187	0.096084097	0.100804414	0.158119084	0.104881833	0.01683095	0.036444172	0.02890031	0.047948946	
	47.02	79.44	41.53	56.62	52.64	55.23	86.63	57.46	9.22	19.97	15.83	26.27	
	15,771.07	26,645.27	13,928.66	18,989.58	17,655.37	18,522.72	29,054.24	19,271.94	3,092.67	6,696.58	5,310.41	8,810.58	183,749.09
	35,016.09	59,159.77	30,925.44	42,162.06	39,199.73	41,125.49	64,508.34	42,788.97	6,866.58	14,868.24	11,790.55	19,561.88	407,973.16
	54.21	91.59	47.88	65.28	60.69	63.67	99.87	66.25	10.63	23.02	18.25	30.29	631.63
	5,240.47	8,853.78	4,628.26	6,309.92	5,866.59	6,154.79	9,654.24	6,403.75	1,027.64	2,225.16	1,764.56	2,927.61	61,056.78
	5,132.07	8,670.65	4,532.53	6,179.41	5,745.24	6,027.49	9,454.55	6,271.29	1,006.39	2,179.14	1,728.06	2,867.05	59,793.89
	9,250.24	15,628.30	8,169.61	11,138.00	10,355.44	10,864.17	17,041.24	11,303.61	1,813.95	3,927.76	3,114.72	5,167.68	107,774.71
	257,199.99	434,540.06	227,153.39	309,688.57	287,929.68	302,074.78	473,826.35	314,293.35	50,436.34	109,210.15	86,603.90	143,685.84	2,996,642.41
	2,205.39	3,726.02	1,947.76	2,655.46	2,468.89	2,590.18	4,062.88	2,694.95	432.47	936.44	742.60	1,232.05	25,695.09
	2,565.39	4,334.23	2,265.69	3,088.92	2,871.89	3,012.98	4,726.08	3,134.85	503.07	1,089.29	863.81	1,433.16	29,889.37
	1.98	3.35	1.75	2.39	2.22	2.33	3.66	2.42	0.39	0.84	0.67	1.11	23.12
	9,416.48	15,909.16	8,316.43	11,338.16	10,541.54	11,059.41	17,347.49	11,506.75	1,846.55	3,998.35	3,170.70	5,260.55	109,711.58
	509.77	861.26	450.22	613.80	570.67	598.71	939.12	622.93	99.96	216.45	171.65	284.78	5,939.32
	63.41	107.13	56.00	76.35	70.99	74.47	116.82	77.49	12.43	26.93	21.35	35.42	738.80
	342,473.67	578,610.17	302,465.23	412,364.64	383,391.67	402,226.53	630,921.68	418,496.11	67,158.31	145,418.36	115,317.09	191,324.34	3,990,167.80
	-	-	-	-	-	-	-	-	-	-	-	-	-
	296.31	500.62	261.69	356.78	331.71	348.01	545.88	362.09	58.11	125.82	99.77	165.53	3,452.31
	36,658.23	61,934.17	32,375.74	44,139.33	41,038.07	43,054.15	67,533.57	44,795.64	7,188.60	15,565.52	12,343.49	20,479.27	427,105.76
	-	-	-	-	-	-	-	-	-	-	-	-	-
	68,246.58	115,302.77	60,273.88	82,174.13	76,400.53	80,153.85	125,727.16	83,395.98	13,383.00	28,978.30	22,979.86	38,126.23	795,142.25
	-	-	-	-	-	-	-	-	-	-	-	-	
	125.76	212.48	111.07	151.43	140.79	147.71	231.69	153.68	24.66	53.40	42.35	70.26	1,465.29
	6,441.77	10,883.39	5,689.23	7,756.39	7,211.42	7,565.70	11,867.35	7,871.72	1,263.22	2,735.25	2,169.06	3,598.72	75,053.23
	296,711.61	501,295.04	262,049.18	357,263.60	332,162.06	348,480.16	546,616.57	362,575.77	58,184.48	125,987.25	99,908.17	165,759.17	3,456,993.06
	8,395.32	14,183.91	7,414.56	10,108.61	9,398.37	9,860.08	15,466.26	10,258.91	1,646.30	3,564.75	2,826.85	4,690.08	97,813.99
	2,941.91	4,970.36	2,598.23	3,542.28	3,293.40	3,455.19	5,419.73	3,594.95	576.90	1,249.17	990.59	1,643.51	34,276.23
	8,576.67	14,490.31	7,574.73	10,326.97	9,601.40	10,073.08	15,800.37	10,480.53	1,681.87	3,641.76	2,887.92	4,791.39	99,927.00
	-	-	-	-	-	-	-	-	-	-	-	-	-
	490.13	828.08	432.88	590.16	548.69	575.65	902.95	598.93	96.11	208.12	165.04	273.82	5,710.56
	510.82	863.04	451.15	615.07	571.85	599.95	941.06	624.21	100.17	216.90	172.00	285.37	5,951.60
	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,335.65	2,256.58	1,179.62	1,608.22	1,495.23	1,568.69	2,460.60	1,632.14	261.92	567.13	449.74	746.17	15,561.68
	417.30	705.03	368.55	502.46	467.16	490.11	768.77	509.93	81.83	177.19	140.51	233.13	4,861.95
	1,451.62	2,452.52	1,282.04	1,747.87	1,625.06	1,704.89	2,674.25	1,773.86	284.66	616.38	488.79	810.96	16,912.90
	432,599.69	730,878.30	382,062.54	520,883.29	484,285.74	508,077.21	796,956.20	528,628.33	84,831.82	183,686.93	145,664.15	241,673.61	5,040,227.82
													-
													1.00

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
10Yr Monthly avg	0.057638486	0.104122247	0.083252597	0.085830919	0.110687585	0.096977645	0.20947868	0.092400201	0.06041718	0.035243372	0.024408515	0.039542571	
	2016												
	3996.22	5937.24	4567.11	5423.43	6041.55	16841.11	4324.32	7881.49	10313.34	8032.42	4540.85	21276.93	99176.01
	11,774.85	8,241.68	9,361.55	6,345.48	10,277.98	1,681.61	24,729.92	11,390.45	-	-	769.56	-	84,573.08
	118010.13	95861.09	119990.51	108800.64	114518.06	107514.78	112373.56	108136.56	102045.31	111317.06	107259.14	113826.38	1319653.22
	139,189.86	287,070.00	105,055.97	180,232.68	173,411.62	194,560.00	361,452.79	206,156.79	-	-	-	29,859.46	1,676,989.19
	3996.22	5937.24	4567.11	5423.43	6041.55	16841.11	4324.32	7881.49	10313.34	8032.42	4540.85	21276.93	99176.01
	32,662.01	52,074.53	27,808.63	38,715.90	34,996.52	26,213.04	63,209.25	36,914.15	-	7,533.10	7,802.64	-	327,929.75
	180726.29	159161.91	209193.24	99682.44	176533.19	144727.56	95162.56	221801.27	123171.53	192283.67	135860.18	125671.16	1863975
	115,985.32	275,836.71	52,855.94	192,594.11	119,676.86	203,752.60	451,454.01	140,774.50	-	-	-	40,088.01	1,593,018.06

Kentucky Utilities Company
Case No. 2016-00370

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	2018												
10Yr Monthly avg	0.085829392	0.145008982	0.075802634	0.103345187	0.096084097	0.100804414	0.158119084	0.104881833	0.016830949	0.036444172	0.02890031	0.047948946	
	48.37	81.72	42.72	58.24	54.15	56.81	89.11	59.11	9.49	20.54	16.29	27.02	
	16,223.52	27,409.68	14,328.26	19,534.37	18,161.87	19,054.11	29,887.76	19,824.82	3,181.40	6,888.70	5,462.75	9,063.34	189,020.58
	36,020.65	60,856.98	31,812.65	43,371.63	40,324.31	42,305.32	66,358.99	44,016.53	7,063.57	15,294.79	12,128.80	20,123.08	419,677.30
	55.77	94.22	49.25	67.15	62.43	65.50	102.74	68.15	10.94	23.68	18.78	31.15	649.75
	5,390.81	9,107.78	4,761.04	6,490.95	6,034.89	6,331.36	9,931.21	6,587.46	1,057.13	2,289.00	1,815.18	3,011.60	62,808.41
	5,279.30	8,919.40	4,662.57	6,356.69	5,910.06	6,200.41	9,725.79	6,451.21	1,035.26	2,241.66	1,777.64	2,949.31	61,509.29
	9,515.61	16,076.65	8,403.98	11,457.53	10,652.52	11,175.84	17,530.13	11,627.89	1,865.99	4,040.44	3,204.08	5,315.94	110,866.60
	264,578.68	447,006.38	233,670.08	318,573.08	296,189.96	310,740.86	487,419.73	323,309.96	51,883.28	112,343.23	89,088.43	147,807.98	3,082,611.66
	2,268.66	3,832.91	2,003.63	2,731.65	2,539.72	2,664.49	4,179.44	2,772.26	444.88	963.30	763.90	1,267.40	26,432.25
	2,638.98	4,458.57	2,330.69	3,177.54	2,954.28	3,099.42	4,861.66	3,224.79	517.50	1,120.54	888.59	1,474.28	30,746.85
	2.04	3.45	1.80	2.46	2.29	2.40	3.76	2.49	0.40	0.87	0.69	1.14	23.78
	9,686.62	16,365.57	8,555.01	11,663.44	10,843.96	11,376.69	17,845.17	11,836.86	1,899.52	4,113.05	3,261.66	5,411.47	112,859.04
	524.39	885.96	463.13	631.41	587.05	615.89	966.06	640.80	102.83	222.66	176.57	292.95	6,109.71
	65.23	110.21	57.61	78.54	73.02	76.61	120.17	79.71	12.79	27.70	21.96	36.44	760.00
	352,298.74	595,209.64	311,142.51	424,194.77	394,390.61	413,765.81	649,021.88	430,502.15	69,084.98	149,590.20	118,625.36	196,813.15	4,104,639.80
	-	-	-	-	-	-	-	-	-	-	-	-	-
	304.81	514.98	269.20	367.02	341.23	357.99	561.54	372.47	59.77	129.43	102.64	170.28	3,551.36
	37,709.90	63,710.97	33,304.55	45,405.62	42,215.39	44,289.31	69,471.01	46,080.76	7,394.83	16,012.07	12,697.61	21,066.79	439,358.80
	-	-	-	-	-	-	-	-	-	-	-	-	-
	70,204.47	118,610.63	62,003.05	84,531.58	78,592.34	82,453.34	129,334.09	85,788.48	13,766.94	29,809.65	23,639.12	39,220.02	817,953.71
	-	-	-	-	-	-	-	-	-	-	-	-	
	129.37	218.58	114.26	155.77	144.83	151.95	238.34	158.09	25.37	54.93	43.56	72.27	1,507.33
	6,626.58	11,195.62	5,852.45	7,978.91	7,418.31	7,782.75	12,207.80	8,097.55	1,299.46	2,813.72	2,231.29	3,701.97	77,206.40
	305,223.83	515,676.46	269,566.98	367,512.96	341,691.30	358,477.54	562,298.20	372,977.53	59,853.70	129,601.64	102,774.39	170,514.56	3,556,169.09
	8,636.16	14,590.82	7,627.27	10,398.61	9,667.99	10,142.95	15,909.96	10,553.22	1,693.53	3,667.02	2,907.95	4,824.63	100,620.13
	3,026.31	5,112.95	2,672.77	3,643.91	3,387.88	3,554.32	5,575.21	3,698.09	593.45	1,285.01	1,019.01	1,690.66	35,259.56
	8,822.73	14,906.02	7,792.04	10,623.24	9,876.85	10,362.06	16,253.65	10,781.20	1,730.12	3,746.23	2,970.77	4,928.85	102,793.76
	-	-	-	-	-	-	-	-	-	-	-	-	-
	504.19	851.84	445.29	607.09	564.43	592.16	928.85	616.12	98.87	214.09	169.77	281.67	5,874.38
	525.48	887.79	464.09	632.71	588.26	617.16	968.06	642.12	103.04	223.12	176.94	293.56	6,122.34
	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,373.97	2,321.32	1,213.46	1,654.36	1,538.13	1,613.69	2,531.19	1,678.96	269.43	583.40	462.64	767.57	16,008.12
	429.27	725.25	379.12	516.87	480.56	504.17	790.82	524.56	84.18	182.27	144.54	239.81	5,001.43
	1,493.27	2,522.88	1,318.82	1,798.01	1,671.68	1,753.81	2,750.97	1,824.75	292.83	634.06	502.81	834.22	17,398.10
	445,010.33	751,846.12	393,023.35	535,826.66	498,179.18	522,653.20	819,819.70	543,793.90	87,265.52	188,956.64	149,843.04	248,606.87	5,184,824.52
													-
													1.00

10Yr Monthly avg	0.057638486	0.104122247	0.083252597	0.085830919	0.110687585	0.096977645	0.20947868	0.092400201	0.060417183	0.035243372	0.024408515	0.039542571	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	2017												
	2506.12	4670.48	3075.68	4157.87	2320.93	12343.76	3075.68	6643.08	5240.05	7756.37	3645.26	13568.2	69003.48
(0.00)	13,717.40	15,308.01	11,252.58	15,376.50	15,840.94	6,710.35	26,812.08	13,181.74	-	-	1,817.49	-	120,017.10
	117358.9	103448.71	123905.31	111337.59	117351.14	106300.35	122554.8	114231.24	101382.21	111559.5	113353.4	115633.76	1358416.91
(0.00)	147,219.78	294,058.74	109,764.77	207,235.49	154,573.85	204,440.51	364,864.93	209,078.72	-	783.73	-	32,174.22	1,724,194.75
	2506.12	4670.48	3075.68	4157.87	2320.93	12343.76	3075.68	6643.08	5240.05	7756.37	3645.26	13568.2	69003.48
0.00	35,203.78	59,040.49	30,228.87	41,247.75	39,894.46	31,945.55	66,395.33	39,437.68	2,154.78	8,255.70	9,052.35	7,498.59	370,355.32
	123165.95	124167.77	116908.18	110301.59	111142.29	109640.46	101911.01	111866.09	109164.56	119886.66	118985.7	130046.26	1387186.52
0.00	182,057.88	342,197.83	152,658.80	241,000.06	230,549.01	248,837.08	460,387.19	261,111.44	-	9,714.98	-	40,468.30	2,168,982.57

Kentucky Utilities Company
Case No. 2016-00370

	2018												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
10Yr Monthly avg	0.085829392	0.145008982	0.075802634	0.103345187	0.096084097	0.100804414	0.158119084	0.104881833	0.016830949	0.036444172	0.02890031	0.047948946	
	49.72	84.00	43.91	59.87	55.66	58.40	91.60	60.76	9.75	21.11	16.74	27.78	
	16,675.97	28,174.10	14,727.85	20,079.15	18,668.38	19,585.50	30,721.28	20,377.71	3,270.12	7,080.81	5,615.10	9,316.10	194,292.07
	37,025.21	62,554.19	32,699.85	44,581.20	41,448.90	43,485.15	68,209.64	45,244.08	7,260.56	15,721.34	12,467.06	20,684.29	431,381.45
	57.32	96.85	50.63	69.02	64.17	67.32	105.60	70.05	11.24	24.34	19.30	32.02	667.87
	5,541.15	9,361.79	4,893.82	6,671.97	6,203.19	6,507.94	10,208.17	6,771.17	1,086.61	2,352.84	1,865.81	3,095.59	64,560.04
	5,426.54	9,168.15	4,792.60	6,533.97	6,074.89	6,373.33	9,997.03	6,631.12	1,064.13	2,304.17	1,827.21	3,031.56	63,224.69
	9,780.99	16,525.01	8,638.35	11,777.06	10,949.60	11,487.52	18,019.01	11,952.18	1,918.03	4,153.12	3,293.44	5,464.19	113,958.50
	271,957.37	459,472.69	240,186.78	327,457.59	304,450.24	319,406.94	501,013.11	332,326.57	53,330.23	115,476.31	91,572.97	151,930.11	3,168,580.91
	2,331.93	3,939.81	2,059.51	2,807.83	2,610.55	2,738.80	4,296.00	2,849.58	457.29	990.17	785.20	1,302.74	27,169.40
	2,712.58	4,582.91	2,395.69	3,266.16	3,036.67	3,185.86	4,997.25	3,314.72	531.93	1,151.79	913.37	1,515.39	31,604.33
	2.10	3.54	1.85	2.53	2.35	2.46	3.87	2.56	0.41	0.89	0.71	1.17	24.45
	9,956.77	16,821.98	8,793.60	11,988.71	11,146.38	11,693.97	18,342.84	12,166.97	1,952.50	4,227.76	3,352.62	5,562.39	116,006.50
	539.02	910.67	476.05	649.02	603.42	633.06	993.00	658.67	105.70	228.87	181.50	301.12	6,280.10
	67.05	113.28	59.22	80.73	75.06	78.75	123.52	81.93	13.15	28.47	22.58	37.46	781.20
	362,123.80	611,809.11	319,819.79	436,024.90	405,389.55	425,305.09	667,122.09	442,508.18	71,011.66	153,762.04	121,933.64	202,301.96	4,219,111.80
	-	-	-	-	-	-	-	-	-	-	-	-	-
	210.40	380.09	303.91	313.32	404.05	354.01	764.68	337.30	220.55	128.65	89.10	144.35	3,650.40
	26,030.22	47,022.84	37,597.86	38,762.26	49,987.82	43,796.25	94,603.05	41,729.02	27,285.11	15,916.32	11,023.17	17,857.89	451,611.83
	-	-	-	-	-	-	-	-	-	-	-	-	-
	48,460.43	87,542.36	69,995.88	72,163.65	93,062.27	81,535.43	176,122.38	77,686.87	50,796.66	29,631.40	20,521.83	33,246.02	840,765.17
	89.30	161.32	128.99	132.98	171.50	150.25	324.56	143.16	93.61	54.60	37.82	61.27	1,549.36
	4,574.17	8,263.10	6,606.89	6,811.50	8,784.12	7,696.10	16,624.14	7,332.84	4,794.68	2,796.90	1,937.05	3,138.08	79,359.56
	210,688.56	380,602.75	304,316.98	313,741.63	404,601.32	354,486.76	765,716.87	337,754.62	220,845.65	128,826.69	89,221.54	144,541.74	3,655,345.12
	5,961.33	10,768.98	8,610.51	8,877.17	11,448.00	10,030.04	21,665.60	9,556.61	6,248.72	3,645.09	2,524.48	4,089.74	103,426.27
	2,088.99	3,773.69	3,017.32	3,110.76	4,011.64	3,514.75	7,592.11	3,348.85	2,189.69	1,277.32	884.64	1,433.14	36,242.89
	6,090.11	11,001.61	8,796.51	9,068.94	11,695.31	10,246.71	22,133.63	9,763.05	6,383.71	3,723.83	2,579.02	4,178.09	105,660.52
	-	-	-	-	-	-	-	-	-	-	-	-	-
	348.03	628.71	502.70	518.27	668.36	585.57	1,264.88	557.93	364.81	212.81	147.38	238.77	6,038.21
	362.72	655.25	523.92	540.14	696.57	610.29	1,318.27	581.48	380.21	221.79	153.60	248.84	6,293.09
	-	-	-	-	-	-	-	-	-	-	-	-	-
	948.42	1,713.29	1,369.89	1,412.31	1,821.32	1,595.72	3,446.88	1,520.41	994.14	579.91	401.63	650.66	16,454.57
	296.31	535.28	427.99	441.25	569.04	498.55	1,076.91	475.02	310.60	181.18	125.48	203.29	5,140.92
	1,030.77	1,862.05	1,488.83	1,534.94	1,979.46	1,734.28	3,746.17	1,652.42	1,080.46	630.27	436.51	707.15	17,883.31
	307,179.77	554,911.31	443,688.16	457,429.12	589,900.76	516,834.72	1,116,400.12	492,439.59	321,988.62	187,826.78	130,083.26	210,739.01	5,329,421.22
													-
													1.00

10Yr Monthly avg	0.057638486	0.104122247	0.083252597	0.085830919	0.110687585	0.096977645	0.20947868	0.092400201	0.060417183	0.035243372	0.024408515	0.039542571	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	2018												
	3645.53	5810.07	4215.14	5297.41	7389.82	11781.06	4215.14	7893.95	6949.3	9203.78	4784.76	10254.96	81440.92
(0.00)	13,030.44	15,623.02	10,512.71	14,781.74	11,278.56	7,804.44	26,506.14	12,483.76	-	-	830.34	-	112,851.15
	110207.7	105174.4	113146.4	119010.31	126371	103642.11	129452.2	114431.4	100700.38	113885.77	106772.17	123806.64	1366600.48
(0.00)	161,749.67	306,928.14	127,040.38	193,248.08	178,079.24	215,764.83	371,560.91	217,895.17	-	1,590.54	-	28,123.47	1,801,980.43
	3645.53	5810.07	4215.14	5297.41	7389.82	11781.06	4215.14	7893.95	6949.3	9203.78	4784.76	10254.96	81440.92
-	22,384.69	41,212.77	33,382.72	33,464.85	42,598.00	32,015.19	90,387.91	33,835.07	20,335.81	6,712.54	6,238.41	7,602.93	370,170.91
	130854.08	132631.54	121724.62	109403.94	113172.36	116712.44	107067.26	116456.05	120164.87	120697.37	118053.74	133956.98	1440895.25
(0.00)	79,834.48	219,139.01	182,592.36	204,337.69	291,428.96	237,774.32	658,649.61	221,298.57	100,680.78	8,129.32	-	10,584.76	2,214,449.87

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

**Response to Commission Staff's Second Request for Information
Dated January 11, 2017**

Question No. 31

Responding Witness: John P. Malloy

Q-31. Refer to FR 16.8.d, Schedule D-1, page 6 of 8, line 108, Uncollectible Accounts. The description of the $675,506 adjustment from the base period to the forecasted test period reads, "Actual bad debt expense in the base year is less than the 5-year average ratio (0 .35% of revenues) used in the budget/test year." Explain why KU chose to use a higher amount of bad debt expense when the trend appears to be decreasing and the overall economy appears to be improving.

A-31. Budget data is commonly derived from 5-year average historical data/costs. The 0.35% of revenues is the five-year historical average from 2011-2015.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 32

Responding Witness: Daniel K. Arbough

Q-32. Refer to FR 16.8.d, Schedule D-1, page 7 of 8, line 124, Administrative and General Salaries. The description of the $2.345 million adjustment from the base period to the forecasted test period reads, "Variance reflects changes in headcount, wage inflation, and less allocated to capital in 2018."

a. Provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment, along with any necessary narrative explanation.

b. Explain why the amount allocated to capital in 2018 is a component of this adjustment.

A-32.

a. The adjustment was calculated by taking the difference between the Forecasted Period and the Base Period (i.e. $33.809 million minus $31.464 million = $2.345 million change). The largest drivers of this increase can be attributed to the overall wage inflation and a decrease in the amount of Capital labor charged by the IT department. The impact of wage inflation was approximately $1.0M and the impact of the decrease in IT capital labor was approximately $1.4M as shown in the attachment which is being provided in Excel format.

b. The Forecasted Period was determined through the yearly budget process. O&M labor costs are derived in PowerPlan by taking the average hourly rate for each department times the number of budgeted headcount in that department less off-duty time. In addition, any budgeted Capital labor is removed to get to the final budgeted O&M labor. Therefore, the impact of the IT department charging less Capital in the forecasted test period is an increase in 920 as that is the account where their O&M labor is charged.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 33

Responding Witness: Daniel K. Arbough

Q-33. Refer to FR 16.8.d, Schedule D-1, page 7 of 8, line 130, Employee Pension and Benefits. The description of the $4.451 million adjustment from the base period to the forecasted test period reads, "Variance reflects higher pension expense due to a decrease in the discount rate and higher medical costs." Provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment, along with any necessary narrative explanation.

A-33. See the attachment being provided in Excel format. The variances explained below as non-jurisdictionalized. The primary variance of $2.260M is related to pension costs. The discount rate for 2016 actuals was 4.58% for the non-union plan and 4.49% for the union plan. The discount rate decreased for the 2017-2018 forecast to 4.42% for the non-union plan and 4.34% for the union plan. See the attachment to KIUC 1-29 for actuarial report. Secondarily, there is an increase in medical costs of $1.289M related to claims experience, inflation and anticipated plan participation. Other related pension costs included an increase in the PBGC premium.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 34

Responding Witness: Daniel K. Arbough

Q-34. Refer to FR 16.8.d, Schedule D-1, page 8 of 8, line 140, Depreciation and Amortization. The description of the $42.1 million adjustment from the base period to the forecasted test period reads, 'Variance is due to increase in plant-in-service and higher proposed depreciation rates."

a. Provide supporting work papers, spreadsheets, etc., which show the derivation of this adjustment, along with any necessary narrative explanation.

b. Provide a work paper, spreadsheet, etc., which quantifies separately the portion of the adjustment due to the increase in plant-in-service and the portion due to higher proposed depreciation rates.

A-34.

a. See the attachment being provided in Excel format.

b. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 35

Responding Witness: Daniel K. Arbough

Q-35. Refer to the Staffieri Testimony, page 4, lines 15-17, that states, "He also provides his recommendation that an ROE of 10.23 percent is a reasonable ROE for both LG&E's electric and gas operations and KU's electric operations." KU last adjusted its base rates in July 2015.[1] Beginning with the month of July 2015 to the most current month's financial statements, provide by month in electronic Excel spreadsheet format, with formulas intact and cells unprotected, the 13-month average ROE for KU. This should be considered an ongoing request.

A-35. See attachment 1 being provided in Excel format for the calculation of Return on Equity (ROE) and attachments 2 and 3 for the source documents. The regulatory ROE percentage calculation is based on net income and total equity as presented in the monthly KPSC financial statements. The GAAP ROE percentage calculation is based on net income and total equity derived from financial reports that are used in the preparation of the SEC quarterly filings.

---

[1] Case No. 2014-00371 , Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates (Ky. PSC, June 30, 2015).

Attachment 1 is being provided in a separate file in Excel format.

Kentucky Utilities Company
Comparative Statement of Income
July 31, 2015

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,738,268,339.08	$ 1,723,034,972.70	$ 15,233,366.38	0.88
Rate Refunds..	(5,979,692.41)	(634,749.00)	(5,344,943.41)	(842.06)
Total Operating Revenues..	1,732,288,646.67	1,722,400,223.70	9,888,422.97	0.57
Fuel for Electric Generation..	568,042,427.89	560,438,243.53	7,604,184.36	1.36
Power Purchased...	69,808,524.53	106,001,512.68	(36,192,988.15)	(34.14)
Other Operation Expenses..	273,164,902.98	263,753,856.59	9,411,046.39	3.57
Maintenance..	133,181,926.68	120,510,279.53	12,671,647.15	10.52
Depreciation..	200,184,411.70	178,343,666.44	21,840,745.26	12.25
Amortization Expense...	10,476,664.27	8,609,579.68	1,867,084.59	21.69
Regulatory Credits...	-	4,833,948.06	(4,833,948.06)	(100.00)
Taxes				
Federal Income...	(83,055,643.34)	41,199,631.47	(124,255,274.81)	(301.59)
State Income...	4,649,502.32	10,913,586.04	(6,264,083.72)	(57.40)
Deferred Federal Income - Net................................	203,449,329.64	77,682,587.51	125,766,742.13	161.90
Deferred State Income - Net....................................	15,775,827.33	9,740,897.10	6,034,930.23	61.95
Property and Other...	36,954,164.77	34,606,189.39	2,347,975.38	6.78
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense...	-	(1,831,399.78)	1,831,399.78	100.00
Total Operating Expenses..	1,432,631,882.23	1,414,802,032.39	17,829,849.84	1.26
Net Operating Income...	299,656,764.44	307,598,191.31	(7,941,426.87)	(2.58)
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,856,644.00	1,871,259.25	(14,615.25)	(0.78)
Other Income Less Deductions.............................	567,749.25	(52,441.70)	620,190.95	1,182.63
AFUDC - Equity..	2,219,393.53	1,065,249.37	1,154,144.16	108.35
Total Other Income Less Deductions......................	4,643,786.78	2,884,066.92	1,759,719.86	61.02
Income Before Interest Charges...............................	304,300,551.22	310,482,258.23	(6,181,707.01)	(1.99)
Interest on Long-Term Debt..	70,888,935.06	67,954,226.38	2,934,708.68	4.32
Amortization of Debt Expense - Net...........................	3,651,830.08	4,686,564.76	(1,034,734.68)	(22.08)
Other Interest Expenses..	3,785,755.56	3,342,416.12	443,339.44	13.26
AFUDC - Borrowed Funds...	(785,248.65)	(351,938.22)	(433,310.43)	(123.12)
Total Interest Charges...	77,541,272.05	75,631,269.04	1,910,003.01	2.53
Net Income...	$ 226,759,279.17	$ 234,850,989.19	$ (8,091,710.02)	(3.45)

Kentucky Utilities Company
Comparative Statement of Income
August 31, 2015

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,745,548,528.81	$ 1,727,071,399.01	$ 18,477,129.80	1.07
Rate Refunds..	(5,982,675.72)	(634,749.00)	(5,347,926.72)	(842.53)
Total Operating Revenues..	1,739,565,853.09	1,726,436,650.01	13,129,203.08	0.76
Fuel for Electric Generation..	566,793,019.96	563,335,606.67	3,457,413.29	0.61
Power Purchased...	66,338,719.76	106,347,153.84	(40,008,434.08)	(37.62)
Other Operation Expenses..	276,741,680.13	263,082,305.18	13,659,374.95	5.19
Maintenance...	134,529,410.08	120,339,672.19	14,189,737.89	11.79
Depreciation...	202,513,002.40	182,145,767.08	20,367,235.32	11.18
Amortization Expense...	10,550,388.71	8,800,469.63	1,749,919.08	19.88
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income..	(80,385,076.59)	43,607,262.82	(123,992,339.41)	(284.34)
State Income...	5,628,214.31	11,511,984.31	(5,883,770.00)	(51.11)
Deferred Federal Income - Net................................	201,709,348.87	75,948,790.18	125,760,558.69	165.59
Deferred State Income - Net...................................	15,699,891.09	8,082,111.66	7,617,779.43	94.25
Property and Other...	36,863,194.62	34,844,782.77	2,018,411.85	5.79
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense..	-	-	-	-
Total Operating Expenses..	1,436,981,636.80	1,418,045,360.48	18,936,276.32	1.34
Net Operating Income...	302,584,216.29	308,391,289.53	(5,807,073.24)	(1.88)
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,854,556.00	1,871,259.25	(16,703.25)	(0.89)
Other Income Less Deductions.............................	561,135.26	(67,473.71)	628,608.97	931.64
AFUDC - Equity..	2,174,694.84	1,138,764.42	1,035,930.42	90.97
Total Other Income Less Deductions......................	4,590,386.10	2,942,549.96	1,647,836.14	56.00
Income Before Interest Charges...............................	307,174,602.39	311,333,839.49	(4,159,237.10)	(1.34)
Interest on Long-Term Debt..	70,891,389.77	68,792,738.88	2,098,650.89	3.05
Amortization of Debt Expense - Net...........................	3,660,239.51	4,692,926.55	(1,032,687.04)	(22.01)
Other Interest Expenses..	3,753,170.13	3,363,675.33	389,494.80	11.58
AFUDC - Borrowed Funds...	(773,585.26)	(373,982.30)	(399,602.96)	(106.85)
Total Interest Charges...	77,531,214.15	76,475,358.46	1,055,855.69	1.38
Net Income...	$ 229,643,388.24	$ 234,858,481.03	$ (5,215,092.79)	(2.22)

Kentucky Utilities Company
Comparative Statement of Income
September 30, 2015

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,759,688,274.48	$ 1,731,944,795.84	$ 27,743,478.64	1.60
Rate Refunds..	(4,799,597.85)	(1,817,826.87)	(2,981,770.98)	(164.03)
Total Operating Revenues..	1,754,888,676.63	1,730,126,968.97	24,761,707.66	1.43
Fuel for Electric Generation..	568,121,380.24	564,545,232.51	3,576,147.73	0.63
Power Purchased...	63,216,806.07	107,025,794.39	(43,808,988.32)	(40.93)
Other Operation Expenses..	281,757,149.14	264,596,165.04	17,160,984.10	6.49
Maintenance...	135,152,893.36	121,994,843.74	13,158,049.62	10.79
Depreciation...	204,466,577.67	183,197,420.20	21,269,157.47	11.61
Amortization Expense...	10,617,154.85	8,991,720.72	1,625,434.13	18.08
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(86,477,681.01)	5,700,924.46	(92,178,605.47)	(1,616.91)
State Income...	3,363,638.25	8,455,148.12	(5,091,509.87)	(60.22)
Deferred Federal Income - Net................................	211,068,948.93	113,954,776.35	97,114,172.58	85.22
Deferred State Income - Net....................................	17,430,137.47	11,869,810.87	5,560,326.60	46.84
Property and Other...	37,170,119.49	35,173,855.41	1,996,264.08	5.68
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense...	-	-	-	-
Total Operating Expenses..	1,445,886,967.92	1,425,505,145.96	20,381,821.96	1.43
Net Operating Income...	309,001,708.71	304,621,823.01	4,379,885.70	1.44
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,852,466.00	1,871,261.25	(18,795.25)	(1.00)
Other Income Less Deductions.............................	622,173.90	(431,041.62)	1,053,215.52	244.34
AFUDC - Equity..	2,129,857.27	1,207,861.42	921,995.85	76.33
Total Other Income Less Deductions......................	4,604,497.17	2,648,081.05	1,956,416.12	73.88
Income Before Interest Charges...............................	313,606,205.88	307,269,904.06	6,336,301.82	2.06
Interest on Long-Term Debt..	71,069,992.26	69,644,747.74	1,425,244.52	2.05
Amortization of Debt Expense - Net...........................	3,670,604.45	4,689,619.89	(1,019,015.44)	(21.73)
Other Interest Expenses..	3,713,684.21	3,413,434.95	300,249.26	8.80
AFUDC - Borrowed Funds...	(761,976.39)	(394,358.54)	(367,617.85)	(93.22)
Total Interest Charges..	77,692,304.53	77,353,444.04	338,860.49	0.44
Net Income...	$ 235,913,901.35	$ 229,916,460.02	$ 5,997,441.33	2.61

Kentucky Utilities Company
Comparative Statement of Income
October 31, 2015

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,761,704,664.85	$ 1,730,910,340.65	$ 30,794,324.20	1.78
Rate Refunds..	(4,799,597.85)	(1,817,826.87)	(2,981,770.98)	(164.03)
Total Operating Revenues..	1,756,905,067.00	1,729,092,513.78	27,812,553.22	1.61
Fuel for Electric Generation..	563,984,192.03	560,602,320.48	3,381,871.55	0.60
Power Purchased...	61,899,747.76	107,804,826.98	(45,905,079.22)	(42.58)
Other Operation Expenses..	283,889,271.99	265,221,042.02	18,668,229.97	7.04
Maintenance...	137,009,096.77	124,654,970.73	12,354,126.04	9.91
Depreciation...	206,049,111.35	184,470,373.64	21,578,737.71	11.70
Amortization Expense...	10,682,873.84	9,152,359.14	1,530,514.70	16.72
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(86,512,425.30)	4,341,954.84	(90,854,380.14)	(2,092.48)
State Income...	3,408,529.56	8,300,797.88	(4,892,268.32)	(58.94)
Deferred Federal Income - Net................................	211,068,948.92	113,954,776.36	97,114,172.56	85.22
Deferred State Income - Net....................................	17,430,137.46	11,869,810.88	5,560,326.58	46.84
Property and Other..	37,302,113.03	35,822,705.84	1,479,407.19	4.13
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense...	-	-	-	-
Total Operating Expenses..	1,446,211,440.87	1,426,195,392.94	20,016,047.93	1.40
Net Operating Income...	310,693,626.13	302,897,120.84	7,796,505.29	2.57
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,850,378.00	1,871,261.25	(20,883.25)	(1.12)
Other Income Less Deductions.............................	661,689.40	(448,200.29)	1,109,889.69	247.63
AFUDC - Equity..	2,085,447.32	1,272,967.23	812,480.09	63.83
Total Other Income Less Deductions......................	4,597,514.72	2,696,028.19	1,901,486.53	70.53
Income Before Interest Charges...............................	315,291,140.85	305,593,149.03	9,697,991.82	3.17
Interest on Long-Term Debt..	72,867,903.59	70,481,464.30	2,386,439.29	3.39
Amortization of Debt Expense - Net...........................	3,695,820.76	4,702,606.44	(1,006,785.68)	(21.41)
Other Interest Expenses..	3,635,606.40	3,381,911.08	253,695.32	7.50
AFUDC - Borrowed Funds...	(750,625.72)	(413,217.21)	(337,408.51)	(81.65)
Total Interest Charges..	79,448,705.03	78,152,764.61	1,295,940.42	1.66
Net Income..	$ 235,842,435.82	$ 227,440,384.42	$ 8,402,051.40	3.69

November 30, 2015

Kentucky Utilities Company
Comparative Statement of Income
November 30, 2015

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,747,761,061.10	$ 1,739,612,699.09	$ 8,148,362.01	0.47
Rate Refunds..	(3,840,131.73)	(2,700,606.53)	(1,139,525.20)	(42.20)
Total Operating Revenues.......................................	1,743,920,929.37	1,736,912,092.56	7,008,836.81	0.40
Fuel for Electric Generation..	552,732,363.04	566,254,838.72	(13,522,475.68)	(2.39)
Power Purchased...	57,067,988.57	108,316,253.64	(51,248,265.07)	(47.31)
Other Operation Expenses..	287,694,927.33	264,984,971.62	22,709,955.71	8.57
Maintenance...	136,225,862.28	129,269,470.90	6,956,391.38	5.38
Depreciation...	207,635,451.96	185,739,445.44	21,896,006.52	11.79
Amortization Expense...	10,755,111.80	9,291,447.07	1,463,664.73	15.75
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(87,509,045.70)	2,704,865.30	(90,213,911.00)	(3,335.25)
State Income...	3,226,775.08	8,002,240.52	(4,775,465.44)	(59.68)
Deferred Federal Income - Net................................	211,068,948.92	113,954,776.36	97,114,172.56	85.22
Deferred State Income - Net...................................	17,430,137.46	11,869,810.88	5,560,326.58	46.84
Property and Other..	37,507,754.87	36,170,358.96	1,337,395.91	3.70
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense...	-	-	-	-
Total Operating Expenses.......................................	1,433,836,119.07	1,436,557,933.56	(2,721,814.49)	(0.19)
Net Operating Income..	310,084,810.30	300,354,159.00	9,730,651.30	3.24
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,848,290.00	1,871,261.25	(22,971.25)	(1.23)
Other Income Less Deductions.............................	122,457.91	(460,113.70)	582,571.61	126.61
AFUDC - Equity..	2,044,099.12	1,333,076.21	711,022.91	53.34
Total Other Income Less Deductions......................	4,014,847.03	2,744,223.76	1,270,623.27	46.30
Income Before Interest Charges...............................	314,099,657.33	303,098,382.76	11,001,274.57	3.63
Interest on Long-Term Debt..	74,327,787.83	70,859,824.16	3,467,963.67	4.89
Amortization of Debt Expense - Net...........................	3,672,923.62	4,701,426.77	(1,028,503.15)	(21.88)
Other Interest Expenses..	3,430,396.18	3,519,359.93	(88,963.75)	(2.53)
AFUDC - Borrowed Funds...	(740,393.97)	(430,276.92)	(310,117.05)	(72.07)
Total Interest Charges..	80,690,713.66	78,650,333.94	2,040,379.72	2.59
Net Income..	$ 233,408,943.67	$ 224,448,048.82	$ 8,960,894.85	3.99

December 31, 2015

Kentucky Utilities Company
Comparative Statement of Income
December 31, 2015

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,732,900,464.71	$ 1,739,900,260.32	$ (6,999,795.61)	(0.40)
Rate Refunds...	(3,840,131.73)	(2,700,606.53)	(1,139,525.20)	(42.20)
Total Operating Revenues..	1,729,060,332.98	1,737,199,653.79	(8,139,320.81)	(0.47)
Fuel for Electric Generation..	540,902,679.46	568,077,778.74	(27,175,099.28)	(4.78)
Power Purchased..	52,003,008.69	108,042,626.50	(56,039,617.81)	(51.87)
Other Operation Expenses..	290,543,682.88	265,953,649.97	24,590,032.91	9.25
Maintenance...	133,441,019.40	130,920,339.04	2,520,680.36	1.93
Depreciation...	209,271,259.89	187,157,353.25	22,113,906.64	11.82
Amortization Expense..	10,864,312.45	9,436,591.36	1,427,721.09	15.13
Regulatory Credits..	-	-	-	-
Taxes				
Federal Income...	(19,453,420.02)	(94,167,437.47)	74,714,017.45	79.34
State Income...	1,153,593.30	6,539,530.82	(5,385,937.52)	(82.36)
Deferred Federal Income - Net................................	142,108,312.83	211,991,146.76	(69,882,833.93)	(32.97)
Deferred State Income - Net...................................	19,219,323.20	13,320,364.90	5,898,958.30	44.29
Property and Other..	38,301,169.54	35,625,305.27	2,675,864.27	7.51
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense...	-	-	-	-
Total Operating Expenses.......................................	1,418,354,785.08	1,442,896,703.29	(24,541,918.21)	(1.70)
Net Operating Income..	310,705,547.90	294,302,950.50	16,402,597.40	5.57
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,846,202.00	1,871,260.00	(25,058.00)	(1.34)
Other Income Less Deductions.............................	826,248.92	(619,005.32)	1,445,254.24	233.48
AFUDC - Equity..	1,975,810.78	1,388,314.10	587,496.68	42.32
Total Other Income Less Deductions......................	4,648,261.70	2,640,568.78	2,007,692.92	76.03
Income Before Interest Charges...............................	315,353,809.60	296,943,519.28	18,410,290.32	6.20
Interest on Long-Term Debt..	75,807,104.44	70,856,018.46	4,951,085.98	6.99
Amortization of Debt Expense - Net...........................	3,641,729.78	3,567,670.20	74,059.58	2.08
Other Interest Expenses..	3,308,559.43	3,515,117.58	(206,558.15)	(5.88)
AFUDC - Borrowed Funds...	(720,592.39)	(445,556.45)	(275,035.94)	(61.73)
Total Interest Charges..	82,036,801.26	77,493,249.79	4,543,551.47	5.86
Net Income..	$ 233,317,008.34	$ 219,450,269.49	$ 13,866,738.85	6.32

January 27, 2016

Kentucky Utilities Company
Comparative Statement of Income
January 31, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	Increase or Decrease %
Electric Operating Revenues......................................	$ 1,737,332,021.61	$ 1,717,295,643.41	$ 20,036,378.20	1.17
Rate Refunds..	(3,840,131.73)	(2,700,606.53)	(1,139,525.20)	(42.20)
Total Operating Revenues..	1,733,491,889.88	1,714,595,036.88	18,896,853.00	1.10
Fuel for Electric Generation..	535,777,978.57	557,850,903.71	(22,072,925.14)	(3.96)
Power Purchased...	48,687,627.07	101,193,176.84	(52,505,549.77)	(51.89)
Other Operation Expenses..	291,343,480.92	266,615,867.13	24,727,613.79	9.27
Maintenance..	133,433,299.07	130,877,993.27	2,555,305.80	1.95
Depreciation..	210,938,028.09	188,716,059.52	22,221,968.57	11.78
Amortization Expense...	10,999,011.73	9,582,259.40	1,416,752.33	14.79
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(16,445,781.36)	(96,879,066.99)	80,433,285.63	83.02
State Income...	1,702,098.84	6,045,008.71	(4,342,909.87)	(71.84)
Deferred Federal Income - Net................................	142,108,312.84	211,991,146.76	(69,882,833.92)	(32.97)
Deferred State Income - Net....................................	19,219,323.20	13,320,364.90	5,898,958.30	44.29
Property and Other..	38,195,543.69	35,847,515.16	2,348,028.53	6.55
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(156.54)	(545.85)	389.31	71.32
Accretion Expense..	-	-	-	-
Total Operating Expenses..	1,415,958,766.12	1,425,160,682.56	(9,201,916.44)	(0.65)
Net Operating Income...	317,533,123.76	289,434,354.32	28,098,769.44	9.71
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,844,114.00	1,871,260.00	(27,146.00)	(1.45)
Other Income Less Deductions.............................	808,332.14	(616,032.68)	1,424,364.82	231.22
AFUDC - Equity..	1,964,083.69	1,337,103.83	626,979.86	46.89
Total Other Income Less Deductions......................	4,616,529.83	2,592,331.15	2,024,198.68	78.08
Income Before Interest Charges...............................	322,149,653.59	292,026,685.47	30,122,968.12	10.32
Interest on Long-Term Debt..	77,314,645.52	70,858,269.31	6,456,376.21	9.11
Amortization of Debt Expense - Net...........................	3,610,782.04	3,527,654.36	83,127.68	2.36
Other Interest Expenses..	3,070,996.55	3,705,541.67	(634,545.12)	(17.12)
AFUDC - Borrowed Funds...	(717,577.32)	(430,970.38)	(286,606.94)	(66.50)
Total Interest Charges..	83,278,846.79	77,660,494.96	5,618,351.83	7.23
Net Income...	$ 238,870,806.80	$ 214,366,190.51	$ 24,504,616.29	11.43

February 19, 2016

Kentucky Utilities Company
Comparative Statement of Income
February 29, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,718,520,611.22	$ 1,727,458,732.46	$ (8,938,121.24)	(0.52)
Rate Refunds	(3,840,131.73)	(2,700,606.53)	(1,139,525.20)	(42.20)
Total Operating Revenues	1,714,680,479.49	1,724,758,125.93	(10,077,646.44)	(0.58)
Fuel for Electric Generation	520,387,577.85	562,373,315.27	(41,985,737.42)	(7.47)
Power Purchased	44,191,347.55	97,569,868.78	(53,378,521.23)	(54.71)
Other Operation Expenses	292,534,757.09	268,924,343.15	23,610,413.94	8.78
Maintenance	133,939,575.56	130,626,641.71	3,312,933.85	2.54
Depreciation	212,561,513.53	190,322,366.83	22,239,146.70	11.69
Amortization Expense	11,112,982.62	9,741,809.56	1,371,173.06	14.08
Regulatory Credits	-	-	-	-
Taxes				
Federal Income	(13,572,496.01)	(99,329,807.40)	85,757,311.39	86.34
State Income	3,570,318.16	4,253,849.26	(683,531.10)	(16.07)
Deferred Federal Income - Net	137,871,394.84	216,228,064.76	(78,356,669.92)	(36.24)
Deferred State Income - Net	17,499,176.84	15,040,511.26	2,458,665.58	16.35
Property and Other	38,239,900.96	36,205,071.02	2,034,829.94	5.62
Investment Tax Credit	-	-	-	-
Loss (Gain) from Disposition of Allowances	(156.54)	(545.85)	389.31	71.32
Accretion Expense	-	-	-	-
Total Operating Expenses	1,398,335,892.45	1,431,955,488.35	(33,619,595.90)	(2.35)
Net Operating Income	316,344,587.04	292,802,637.58	23,541,949.46	8.04
Other Income Less Deductions				
Amortization of Investment Tax Credit	1,842,026.00	1,871,260.00	(29,234.00)	(1.56)
Other Income Less Deductions	(343,988.57)	473,861.56	(817,850.13)	(172.59)
AFUDC - Equity	1,954,068.92	1,283,652.50	670,416.42	52.23
Total Other Income Less Deductions	3,452,106.35	3,628,774.06	(176,667.71)	(4.87)
Income Before Interest Charges	319,796,693.39	296,431,411.64	23,365,281.75	7.88
Interest on Long-Term Debt	78,802,996.80	70,867,739.27	7,935,257.53	11.20
Amortization of Debt Expense - Net	3,587,944.95	3,508,301.78	79,643.17	2.27
Other Interest Expenses	3,039,062.71	3,659,095.22	(620,032.51)	(16.95)
AFUDC - Borrowed Funds	(715,248.20)	(415,672.85)	(299,575.35)	(72.07)
Total Interest Charges	84,714,756.26	77,619,463.42	7,095,292.84	9.14
Net Income	$ 235,081,937.13	$ 218,811,948.22	$ 16,269,988.91	7.44

March 21, 2016

Kentucky Utilities Company
Comparative Statement of Income
March 31, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,699,269,049.54	$ 1,727,716,921.05	$ (28,447,871.51)	(1.65)
Rate Refunds..	(2,444,627.73)	(4,096,110.53)	1,651,482.80	40.32
Total Operating Revenues.......................................	1,696,824,421.81	1,723,620,810.52	(26,796,388.71)	(1.55)
Fuel for Electric Generation..	509,787,876.05	559,035,897.51	(49,248,021.46)	(8.81)
Power Purchased...	40,957,925.52	91,096,195.02	(50,138,269.50)	(55.04)
Other Operation Expenses..	293,295,836.16	269,739,300.44	23,556,535.72	8.73
Maintenance...	132,601,938.94	133,264,539.89	(662,600.95)	(0.50)
Depreciation...	214,128,698.38	191,977,432.31	22,151,266.07	11.54
Amortization Expense...	11,207,062.35	9,918,080.78	1,288,981.57	13.00
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(20,384,961.89)	(101,543,537.49)	81,158,575.60	79.92
State Income...	(35,383.50)	6,152,771.72	(6,188,155.22)	(100.58)
Deferred Federal Income - Net................................	142,416,712.29	219,641,524.51	(77,224,812.22)	(35.16)
Deferred State Income - Net...................................	20,297,583.63	13,711,124.71	6,586,458.92	48.04
Property and Other..	38,511,516.96	36,497,265.71	2,014,251.25	5.52
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(91.89)	(156.51)	64.62	41.29
Accretion Expense...	-	-	-	-
Total Operating Expenses..	1,382,784,713.00	1,429,490,438.60	(46,705,725.60)	(3.27)
Net Operating Income..	314,039,708.81	294,130,371.92	19,909,336.89	6.77
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,846,202.00	1,864,996.00	(18,794.00)	(1.01)
Other Income Less Deductions.............................	(600,811.39)	729,006.69	(1,329,818.08)	(182.42)
AFUDC - Equity..	1,079,828.82	2,090,525.97	(1,010,697.15)	(48.35)
Total Other Income Less Deductions......................	2,325,219.43	4,684,528.66	(2,359,309.23)	(50.36)
Income Before Interest Charges...............................	316,364,928.24	298,814,900.58	17,550,027.66	5.87
Interest on Long-Term Debt..	80,344,503.29	70,865,418.01	9,479,085.28	13.38
Amortization of Debt Expense - Net...........................	3,553,772.26	3,518,043.96	35,728.30	1.02
Other Interest Expenses...	2,855,239.49	3,737,554.89	(882,315.40)	(23.61)
AFUDC - Borrowed Funds...	(389,319.09)	(722,677.55)	333,358.46	46.13
Total Interest Charges...	86,364,195.95	77,398,339.31	8,965,856.64	11.58
Net Income..	$ 230,000,732.29	$ 221,416,561.27	$ 8,584,171.02	3.88

Kentucky Utilities Company
Comparative Statement of Income
April 30, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 1,705,629,074.08	$ 1,721,379,684.17	$ (15,750,610.09)	(0.92)
Rate Refunds..	(200,075.26)	(6,340,663.00)	6,140,587.74	96.84
Total Operating Revenues..	1,705,428,998.82	1,715,039,021.17	(9,610,022.35)	(0.56)
Fuel for Electric Generation..	505,884,369.23	558,895,631.19	(53,011,261.96)	(9.49)
Power Purchased..	38,660,316.90	83,444,996.66	(44,784,679.76)	(53.67)
Other Operation Expenses...	293,693,600.64	269,685,062.01	24,008,538.63	8.90
Maintenance..	131,195,531.96	133,907,781.80	(2,712,249.84)	(2.03)
Depreciation..	215,672,768.16	193,616,614.49	22,056,153.67	11.39
Amortization Expense..	11,289,697.92	10,091,064.19	1,198,633.73	11.88
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income..	(16,398,743.88)	(102,537,251.37)	86,138,507.49	84.01
State Income..	691,586.34	5,971,547.31	(5,279,960.97)	(88.42)
Deferred Federal Income - Net..................................	142,416,712.29	219,641,524.51	(77,224,812.22)	(35.16)
Deferred State Income - Net.......................................	20,297,583.63	13,711,124.71	6,586,458.92	48.04
Property and Other..	39,133,799.89	36,342,318.72	2,791,481.17	7.68
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances................	(91.81)	(156.54)	64.73	41.35
Accretion Expense...	-	-	-	-
Total Operating Expenses...	1,382,537,131.27	1,422,770,257.68	(40,233,126.41)	(2.83)
Net Operating Income...	322,891,867.55	292,268,763.49	30,623,104.06	10.48
Other Income Less Deductions				
Amortization of Investment Tax Credit....................	1,846,202.00	1,862,908.00	(16,706.00)	(0.90)
Other Income Less Deductions................................	(598,732.51)	771,243.62	(1,369,976.13)	(177.63)
AFUDC - Equity..	917,417.49	2,184,105.41	(1,266,687.92)	(58.00)
Total Other Income Less Deductions.........................	2,164,886.98	4,818,257.03	(2,653,370.05)	(55.07)
Income Before Interest Charges..................................	325,056,754.53	297,087,020.52	27,969,734.01	9.41
Interest on Long-Term Debt..	81,925,386.11	70,860,825.24	11,064,560.87	15.61
Amortization of Debt Expense - Net.............................	3,520,858.83	3,517,848.30	3,010.53	0.09
Other Interest Expenses...	2,699,710.63	3,763,588.84	(1,063,878.21)	(28.27)
AFUDC - Borrowed Funds..	(332,585.17)	(760,104.86)	427,519.69	56.24
Total Interest Charges...	87,813,370.40	77,382,157.52	10,431,212.88	13.48
Net Income..	$ 237,243,384.13	$ 219,704,863.00	$ 17,538,521.13	7.98

May 20, 2016

Kentucky Utilities Company
Comparative Statement of Income
May 31, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues......................................	$ 1,700,776,204.48	$ 1,720,913,856.18	$ (20,137,651.70)	(1.17)
Rate Refunds..	(3,961.26)	(6,536,777.00)	6,532,815.74	99.94
Total Operating Revenues..	1,700,772,243.22	1,714,377,079.18	(13,604,835.96)	(0.79)
Fuel for Electric Generation..	495,671,442.47	561,782,292.81	(66,110,850.34)	(11.77)
Power Purchased...	37,492,429.49	77,296,668.29	(39,804,238.80)	(51.50)
Other Operation Expenses..	295,540,608.36	271,284,533.96	24,256,074.40	8.94
Maintenance..	129,558,408.96	133,193,007.19	(3,634,598.23)	(2.73)
Depreciation..	217,053,745.15	195,411,762.78	21,641,982.37	11.08
Amortization Expense...	11,360,919.82	10,258,246.61	1,102,673.21	10.75
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(30,603,250.78)	(102,689,741.13)	72,086,490.35	70.20
State Income...	(2,467,587.84)	5,943,737.62	(8,411,325.46)	(141.52)
Deferred Federal Income - Net................................	158,116,112.46	219,641,524.51	(61,525,412.05)	(28.01)
Deferred State Income - Net....................................	23,359,693.06	13,711,124.71	9,648,568.35	70.37
Property and Other..	39,214,791.64	36,566,206.86	2,648,584.78	7.24
Investment Tax Credit..	-	-	-	-
Loss (Gain) from Disposition of Allowances.............	(91.81)	(156.54)	64.73	41.35
Accretion Expense..	-	-	-	-
Total Operating Expenses..	1,374,297,220.98	1,422,399,207.67	(48,101,986.69)	(3.38)
Net Operating Income...	326,475,022.24	291,977,871.51	34,497,150.73	11.82
Other Income Less Deductions				
Amortization of Investment Tax Credit................	1,846,202.00	1,860,820.00	(14,618.00)	(0.79)
Other Income Less Deductions.............................	(366,710.71)	506,518.83	(873,229.54)	(172.40)
AFUDC - Equity..	770,801.51	2,260,558.30	(1,489,756.79)	(65.90)
Total Other Income Less Deductions......................	2,250,292.80	4,627,897.13	(2,377,604.33)	(51.38)
Income Before Interest Charges...............................	328,725,315.04	296,605,768.64	32,119,546.40	10.83
Interest on Long-Term Debt..	83,492,552.25	70,862,976.21	12,629,576.04	17.82
Amortization of Debt Expense - Net...........................	3,486,869.58	3,527,433.31	(40,563.73)	(1.15)
Other Interest Expenses..	2,495,774.49	3,775,518.37	(1,279,743.88)	(33.90)
AFUDC - Borrowed Funds...	(281,528.12)	(791,509.07)	509,980.95	64.43
Total Interest Charges..	89,193,668.20	77,374,418.82	11,819,249.38	15.28
Net Income..	$ 239,531,646.84	$ 219,231,349.82	$ 20,300,297.02	9.26

June 31, 2016

Kentucky Utilities Company
Comparative Statement of Income
June 30, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 1,708,503,543.59	$ 1,721,828,711.12	$ (13,325,167.53)	(0.77)
Rate Refunds..	(3,961.26)	(6,519,125.50)	6,515,164.24	99.94
Total Operating Revenues..	1,708,499,582.33	1,715,309,585.62	(6,810,003.29)	(0.40)
Fuel for Electric Generation..	491,140,603.66	563,163,071.71	(72,022,468.05)	(12.79)
Power Purchased..	37,918,823.84	73,887,266.95	(35,968,443.11)	(48.68)
Other Operation Expenses..	293,764,611.97	272,234,152.44	21,530,459.53	7.91
Maintenance..	130,031,763.92	132,603,832.38	(2,572,068.46)	(1.94)
Depreciation..	217,835,124.33	197,657,965.45	20,177,158.88	10.21
Amortization Expense..	11,430,827.09	10,387,567.39	1,043,259.70	10.04
Regulatory Credits..	-	-	-	-
Taxes				
Federal Income...	(5,188,016.36)	(86,920,110.17)	81,732,093.81	94.03
State Income...	2,281,817.94	3,944,736.34	(1,662,918.40)	(42.16)
Deferred Federal Income - Net..................................	131,631,505.78	203,449,329.64	(71,817,823.86)	(35.30)
Deferred State Income - Net......................................	19,545,029.95	15,775,827.33	3,769,202.62	23.89
Property and Other..	39,228,574.34	36,763,925.41	2,464,648.93	6.70
Investment Tax Credit...	4,000,000.00	-	4,000,000.00	-
Loss (Gain) from Disposition of Allowances................	(91.81)	(156.54)	64.73	41.35
Accretion Expense..	-	-	-	-
Total Operating Expenses...	1,373,620,574.65	1,422,947,408.33	(49,326,833.68)	(3.47)
Net Operating Income...	334,879,007.68	292,362,177.29	42,516,830.39	14.54
Other Income Less Deductions				
Amortization of Investment Tax Credit...................	1,846,202.00	1,858,732.00	(12,530.00)	(0.67)
Other Income Less Deductions................................	(788,133.02)	665,026.40	(1,453,159.42)	(218.51)
AFUDC - Equity..	691,260.29	2,265,488.32	(1,574,228.03)	(69.49)
Total Other Income Less Deductions.........................	1,749,329.27	4,789,246.72	(3,039,917.45)	(63.47)
Income Before Interest Charges..................................	336,628,336.95	297,151,424.01	39,476,912.94	13.29
Interest on Long-Term Debt..	85,049,876.35	70,876,397.44	14,173,478.91	20.00
Amortization of Debt Expense - Net.............................	3,453,958.85	3,530,616.11	(76,657.26)	(2.17)
Other Interest Expenses..	2,511,211.87	3,814,044.64	(1,302,832.77)	(34.16)
AFUDC - Borrowed Funds..	(254,360.89)	(797,464.31)	543,103.42	68.10
Total Interest Charges..	90,760,686.18	77,423,593.88	13,337,092.30	17.23
Net Income...	$ 245,867,650.77	$ 219,727,830.13	$ 26,139,820.64	11.90

July 27, 2016

Kentucky Utilities Company
Comparative Statement of Income
July 31, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues..	$ 1,711,143,852.51	$ 1,738,268,339.08	$ (27,124,486.57)	(1.56)
Rate Refunds..	73,703.15	(5,979,692.41)	6,053,395.56	101.23
Total Operating Revenues..	1,711,217,555.66	1,732,288,646.67	(21,071,091.01)	(1.22)
Fuel for Electric Generation..	486,403,212.13	568,042,427.89	(81,639,215.76)	(14.37)
Power Purchased..	38,915,387.85	69,808,524.53	(30,893,136.68)	(44.25)
Other Operation Expenses...	295,160,574.31	273,164,902.98	21,995,671.33	8.05
Maintenance...	129,384,847.72	133,181,926.68	(3,797,078.96)	(2.85)
Depreciation...	218,176,399.90	200,184,411.70	17,991,988.20	8.99
Amortization Expense..	11,500,244.42	10,476,664.27	1,023,580.15	9.77
Regulatory Dedits...	-	-	-	-
Regulatory Credits..	-	-	-	-
Taxes				
Federal Income..	(4,046,633.04)	(83,055,643.34)	79,009,010.30	95.13
State Income...	2,489,972.97	4,649,502.32	(2,159,529.35)	(46.45)
Deferred Federal Income - Net...................................	131,631,505.78	203,449,329.64	(71,817,823.86)	(35.30)
Deferred State Income - Net.......................................	19,545,029.95	15,775,827.33	3,769,202.62	23.89
Property and Other..	39,652,117.10	36,954,164.77	2,697,952.33	7.30
Investment Tax Credit..	4,000,000.00	-	4,000,000.00	-
Loss (Gain) from Disposition of Allowances................	(91.81)	(156.54)	64.73	41.35
Accretion Expense..	-	-	-	-
Total Operating Expenses...	1,372,812,567.28	1,432,631,882.23	(59,819,314.95)	(4.18)
Net Operating Income..	338,404,988.38	299,656,764.44	38,748,223.94	12.93
Other Income Less Deductions				
Amortization of Investment Tax Credit....................	1,846,202.00	1,856,644.00	(10,442.00)	(0.56)
Other Income Less Deductions................................	(765,445.78)	567,749.25	(1,333,195.03)	(234.82)
AFUDC - Equity..	657,465.72	2,219,393.53	(1,561,927.81)	(70.38)
Total Other Income Less Deductions.........................	1,738,221.94	4,643,786.78	(2,905,564.84)	(62.57)
Income Before Interest Charges..................................	340,143,210.32	304,300,551.22	35,842,659.10	11.78
Interest on Long-Term Debt..	86,641,312.10	70,888,935.06	15,752,377.04	22.22
Amortization of Debt Expense - Net.............................	3,314,055.02	3,651,830.08	(337,775.06)	(9.25)
Other Interest Expenses...	2,454,997.78	3,785,755.56	(1,330,757.78)	(35.15)
AFUDC - Borrowed Funds..	(243,417.87)	(785,248.65)	541,830.78	69.00
Total Interest Charges...	92,166,947.03	77,541,272.05	14,625,674.98	18.86
Net Income..	$ 247,976,263.29	$ 226,759,279.17	$ 21,216,984.12	9.36

August 19, 2016

Kentucky Utilities Company
Comparative Statement of Income
August 31, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 1,719,846,885.66	$ 1,745,548,528.81	$ (25,701,643.15)	(1.47)
Rate Refunds..	76,686.46	(5,982,675.72)	6,059,362.18	101.28
Total Operating Revenues..	1,719,923,572.12	1,739,565,853.09	(19,642,280.97)	(1.13)
Fuel for Electric Generation..	486,802,442.82	566,793,019.96	(79,990,577.14)	(14.11)
Power Purchased...	38,544,834.09	66,338,719.76	(27,793,885.67)	(41.90)
Other Operation Expenses...	296,204,208.48	276,741,680.13	19,462,528.35	7.03
Maintenance..	129,353,982.34	134,529,410.08	(5,175,427.74)	(3.85)
Depreciation..	218,690,510.76	202,513,002.40	16,177,508.36	7.99
Amortization Expense..	11,590,545.81	10,550,388.71	1,040,157.10	9.86
Regulatory Dedits..	33,928.72	-	33,928.72	100.00
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(508,887.72)	(80,385,076.59)	79,876,188.87	99.37
State Income...	2,592,363.03	5,628,214.31	(3,035,851.28)	(53.94)
Deferred Federal Income - Net...................................	130,076,697.01	201,709,348.87	(71,632,651.86)	(35.51)
Deferred State Income - Net.......................................	19,614,396.47	15,699,891.09	3,914,505.38	24.93
Property and Other..	40,041,267.00	36,863,194.62	3,178,072.38	8.62
Investment Tax Credit..	4,000,000.00	-	4,000,000.00	-
Loss (Gain) from Disposition of Allowances................	(91.81)	(156.54)	64.73	41.35
Accretion Expense...	-	-	-	-
Total Operating Expenses...	1,377,036,197.00	1,436,981,636.80	(59,945,439.80)	(4.17)
Net Operating Income...	342,887,375.12	302,584,216.29	40,303,158.83	13.32
Other Income Less Deductions				
Amortization of Investment Tax Credit...................	1,846,202.00	1,854,556.00	(8,354.00)	(0.45)
Other Income Less Deductions................................	(518,531.13)	561,135.26	(1,079,666.39)	(192.41)
AFUDC - Equity..	620,010.69	2,174,694.84	(1,554,684.15)	(71.49)
Total Other Income Less Deductions.........................	1,947,681.56	4,590,386.10	(2,642,704.54)	(57.57)
Income Before Interest Charges..................................	344,835,056.68	307,174,602.39	37,660,454.29	12.26
Interest on Long-Term Debt..	88,340,333.52	70,891,389.77	17,448,943.75	24.61
Amortization of Debt Expense - Net.............................	3,282,749.66	3,660,239.51	(377,489.85)	(10.31)
Other Interest Expenses...	2,396,055.73	3,753,170.13	(1,357,114.40)	(36.16)
AFUDC - Borrowed Funds..	(231,145.99)	(773,585.26)	542,439.27	70.12
Total Interest Charges...	93,787,992.92	77,531,214.15	16,256,778.77	20.97
Net Income..	$ 251,047,063.76	$ 229,643,388.24	$ 21,403,675.52	9.32

September 22, 2016

Kentucky Utilities Company
Comparative Statement of Income
September 30, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 1,720,822,241.26	$ 1,759,688,274.48	$ (38,866,033.22)	(2.21)
Rate Refunds..	76,686.46	(4,799,597.85)	4,876,284.31	101.60
Total Operating Revenues..	1,720,898,927.72	1,754,888,676.63	(33,989,748.91)	(1.94)
Fuel for Electric Generation..	485,068,525.59	568,121,380.24	(83,052,854.65)	(14.62)
Power Purchased..	38,714,938.11	63,216,806.07	(24,501,867.96)	(38.76)
Other Operation Expenses...	292,746,803.43	281,757,149.14	10,989,654.29	3.90
Maintenance..	129,052,395.84	135,152,893.36	(6,100,497.52)	(4.51)
Depreciation..	219,415,969.65	204,466,577.67	14,949,391.98	7.31
Amortization Expense..	11,690,611.85	10,617,154.85	1,073,457.00	10.11
Regulatory Dedits..	56,089.10	-	56,089.10	100.00
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income..	3,423,661.69	(86,477,681.01)	89,901,342.70	103.96
State Income...	2,832,624.09	3,363,638.25	(531,014.16)	(15.79)
Deferred Federal Income - Net...................................	127,291,892.43	211,068,948.93	(83,777,056.50)	(39.69)
Deferred State Income - Net.......................................	20,217,744.33	17,430,137.47	2,787,606.86	15.99
Property and Other..	39,948,745.59	37,170,119.49	2,778,626.10	7.48
Investment Tax Credit..	4,000,000.00	-	4,000,000.00	100.00
Loss (Gain) from Disposition of Allowances................	(91.81)	(156.54)	64.73	41.35
Accretion Expense...	-	-	-	-
Total Operating Expenses...	1,374,459,909.89	1,445,886,967.92	(71,427,058.03)	(4.94)
Net Operating Income...	346,439,017.83	309,001,708.71	37,437,309.12	12.12
Other Income Less Deductions				
Amortization of Investment Tax Credit...................	1,846,202.00	1,852,466.00	(6,264.00)	(0.34)
Other Income Less Deductions................................	(1,182,579.90)	622,173.90	(1,804,753.80)	(290.07)
AFUDC - Equity..	564,075.30	2,129,857.27	(1,565,781.97)	(73.52)
Total Other Income Less Deductions.........................	1,227,697.40	4,604,497.17	(3,376,799.77)	(73.34)
Income Before Interest Charges..................................	347,666,715.23	313,606,205.88	34,060,509.35	10.86
Interest on Long-Term Debt..	89,807,001.34	71,069,992.26	18,737,009.08	26.36
Amortization of Debt Expense - Net.............................	3,250,157.90	3,670,604.45	(420,446.55)	(11.45)
Other Interest Expenses...	2,732,389.27	3,713,684.21	(981,294.94)	(26.42)
AFUDC - Borrowed Funds..	(211,797.67)	(761,976.39)	550,178.72	72.20
Total Interest Charges...	95,577,750.84	77,692,304.53	17,885,446.31	23.02
Net Income...	$ 252,088,964.39	$ 235,913,901.35	$ 16,175,063.04	6.86

October 26, 2016

Attachment 2 to Response to PSC-2 Question No. 35

Arbough

Kentucky Utilities Company
Comparative Statement of Income
October 31, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues.....................................	$ 1,725,303,665.54	$ 1,761,704,664.85	$ (36,400,999.31)	(2.07)
Rate Refunds...	76,686.46	(4,799,597.85)	4,876,284.31	101.60
Total Operating Revenues......................................	1,725,380,352.00	1,756,905,067.00	(31,524,715.00)	(1.79)
Fuel for Electric Generation......................................	489,998,189.12	563,984,192.03	(73,986,002.91)	(13.12)
Power Purchased...	37,270,497.61	61,899,747.76	(24,629,250.15)	(39.79)
Other Operation Expenses..	291,505,172.41	283,889,271.99	7,615,900.42	2.68
Maintenance..	126,218,584.95	137,009,096.77	(10,790,511.82)	(7.88)
Depreciation..	220,360,468.55	206,049,111.35	14,311,357.20	6.95
Amortization Expense...	11,788,402.58	10,682,873.84	1,105,528.74	10.35
Regulatory Dedits..	84,548.15		84,548.15	100.00
Regulatory Credits..	-	-	-	-
Taxes				
Federal Income...	4,768,192.96	(86,512,425.30)	91,280,618.26	105.51
State Income...	3,262,443.87	3,408,529.56	(146,085.69)	(4.29)
Deferred Federal Income - Net...............................	127,291,892.43	211,068,948.92	(83,777,056.49)	(39.69)
Deferred State Income - Net...................................	20,217,744.33	17,430,137.46	2,787,606.87	15.99
Property and Other...	39,916,073.51	37,302,113.03	2,613,960.48	7.01
Investment Tax Credit..	4,000,000.00	-	4,000,000.00	100.00
Loss (Gain) from Disposition of Allowances............	(91.81)	(156.54)	64.73	41.35
Accretion Expense..	-	-	-	-
Total Operating Expenses......................................	1,376,682,118.66	1,446,211,440.87	(69,529,322.21)	(4.81)
Net Operating Income...	348,698,233.34	310,693,626.13	38,004,607.21	12.23
Other Income Less Deductions				
Amortization of Investment Tax Credit..............	1,846,202.00	1,850,378.00	(4,176.00)	(0.23)
Other Income Less Deductions...........................	(1,127,081.15)	661,689.40	(1,788,770.55)	(270.33)
AFUDC - Equity...	496,191.92	2,085,447.32	(1,589,255.40)	(76.21)
Total Other Income Less Deductions.....................	1,215,312.77	4,597,514.72	(3,382,201.95)	(73.57)
Income Before Interest Charges.............................	349,913,546.11	315,291,140.85	34,622,405.26	10.98
Interest on Long-Term Debt......................................	89,671,802.36	72,867,903.59	16,803,898.77	23.06
Amortization of Debt Expense - Net.........................	3,205,278.85	3,695,820.76	(490,541.91)	(13.27)
Other Interest Expenses..	2,650,802.80	3,635,606.40	(984,803.60)	(27.09)
AFUDC - Borrowed Funds.......................................	(187,920.87)	(750,625.72)	562,704.85	74.96
Total Interest Charges..	95,339,963.14	79,448,705.03	15,891,258.11	20.00
Net Income...	$ 254,573,582.97	$ 235,842,435.82	$ 18,731,147.15	7.94

Attachment 2 to Response to PSC-2 Question No. 35

Arbough

Kentucky Utilities Company
Comparative Statement of Income
November 30, 2016

	Year Ended Current Month			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,728,116,532.06	$ 1,747,761,061.10	$ (19,644,529.04)	(1.12)
Rate Refunds	-	(3,840,131.73)	3,840,131.73	100.00
Total Operating Revenues	1,728,116,532.06	1,743,920,929.37	(15,804,397.31)	(0.91)
Fuel for Electric Generation	490,550,137.55	552,732,363.04	(62,182,225.49)	(11.25)
Power Purchased	36,246,206.15	57,067,988.57	(20,821,782.42)	(36.49)
Other Operation Expenses	290,255,008.71	287,694,927.33	2,560,081.38	0.89
Maintenance	124,947,154.85	136,225,862.28	(11,278,707.43)	(8.28)
Depreciation	221,301,319.93	207,635,451.96	13,665,867.97	6.58
Amortization Expense	11,884,464.27	10,755,111.80	1,129,352.47	10.50
Regulatory Dedits	116,314.00	-	116,314.00	100.00
Regulatory Credits	-	-	-	-
Taxes				
Federal Income	6,220,600.15	(87,509,045.70)	93,729,645.85	107.11
State Income	3,527,320.55	3,226,775.08	300,545.47	9.31
Deferred Federal Income - Net	127,291,892.44	211,068,948.92	(83,777,056.48)	(39.69)
Deferred State Income - Net	20,217,744.33	17,430,137.46	2,787,606.87	15.99
Property and Other	40,036,254.11	37,507,754.87	2,528,499.24	6.74
Investment Tax Credit	4,000,000.00	-	4,000,000.00	100.00
Loss (Gain) from Disposition of Allowances	(91.81)	(156.54)	64.73	41.35
Accretion Expense	-	-	-	-
Total Operating Expenses	1,376,594,325.23	1,433,836,119.07	(57,241,793.84)	(3.99)
Net Operating Income	351,522,206.83	310,084,810.30	41,437,396.53	13.36
Other Income Less Deductions				
Amortization of Investment Tax Credit	1,846,202.00	1,848,290.00	(2,088.00)	(0.11)
Other Income Less Deductions	(535,170.69)	122,457.91	(657,628.60)	(537.02)
AFUDC - Equity	425,414.47	2,044,099.12	(1,618,684.65)	(79.19)
Total Other Income Less Deductions	1,736,445.78	4,014,847.03	(2,278,401.25)	(56.75)
Income Before Interest Charges	353,258,652.61	314,099,657.33	39,158,995.28	12.47
Interest on Long-Term Debt	89,840,382.55	74,327,787.83	15,512,594.72	20.87
Amortization of Debt Expense - Net	3,210,113.71	3,672,923.62	(462,809.91)	(12.60)
Other Interest Expenses	2,579,131.75	3,430,396.18	(851,264.43)	(24.82)
AFUDC - Borrowed Funds	(163,036.21)	(740,393.97)	577,357.76	77.98
Total Interest Charges	95,466,591.80	80,690,713.66	14,775,878.14	18.31
Net Income	$ 257,792,060.81	$ 233,408,943.67	$ 24,383,117.14	10.45

December 21, 2016

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 08/31/14	Month Ended 09/30/14	Month Ended 10/31/14	Month Ended 11/30/14
Operating Revenues				
Utility revenues	148,506,446.63	127,814,006.83	122,426,990.51	137,719,557.98
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	989,175.14	1,161,878.35	1,398,875.91	603,452.43
Total Operating Revenues	149,495,621.77	128,975,885.18	123,825,866.42	138,323,010.41
Operating Expenses				
Fuel	(50,722,272.03)	(42,450,820.34)	(37,614,211.14)	(45,503,036.11)
Energy purchases	(1,511,900.47)	(1,559,121.21)	(1,484,580.26)	(1,743,198.89)
Energy purchases from affiliate	(4,216,088.66)	(3,919,687.23)	(3,149,853.41)	(6,671,333.43)
Other operation and maintenance	(30,662,414.78)	(32,744,790.21)	(36,146,674.85)	(34,717,453.85)
Depreciation	(16,491,433.44)	(16,782,728.70)	(17,049,669.49)	(17,078,437.53)
Taxes, other than income	(2,257,587.53)	(2,257,197.65)	(2,258,012.23)	(2,257,616.62)
Total Operating Expenses	(105,861,696.91)	(99,714,345.34)	(97,703,001.38)	(107,971,076.43)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	43,633,924.86	29,261,539.84	26,122,865.04	30,351,933.98
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	(177,612.27)	(168,958.51)	(173,842.13)	(103,772.16)
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(6,429,226.14)	(6,443,591.43)	(6,489,747.32)	(6,529,818.80)
Interest Expense with Affiliate	(807.02)	0.00	0.00	0.00
Income (Loss) from Continuing Operations Before Income Taxes	37,026,279.43	22,648,989.90	19,459,275.59	23,718,343.02
Income Taxes	(14,091,620.03)	(8,505,478.85)	(7,470,840.29)	(9,070,497.44)
Income (Loss) from Continuing Operations After Income Taxes	22,934,659.40	14,143,511.05	11,988,435.30	14,647,845.58
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	22,934,659.40	14,143,511.05	11,988,435.30	14,647,845.58

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 12/31/14	Month Ended 01/31/15	Month Ended 02/28/15	Month Ended 03/31/15
Operating Revenues				
Utility revenues	150,214,044.89	166,463,074.02	166,985,066.46	147,916,096.88
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	176,333.45	628,951.71	2,067,701.67	694,214.73
Total Operating Revenues	150,390,378.34	167,092,025.73	169,052,768.13	148,610,311.61
Operating Expenses				
Fuel	(49,340,157.87)	(52,890,966.87)	(53,914,009.36)	(43,995,313.26)
Energy purchases	(2,516,569.46)	(1,589,925.56)	(1,307,614.54)	(1,717,146.93)
Energy purchases from affiliate	(4,892,915.97)	(7,541,872.36)	(8,481,320.71)	(5,867,453.19)
Other operation and maintenance	(35,075,969.87)	(31,777,374.72)	(32,676,941.04)	(39,803,381.04)
Depreciation	(17,258,706.68)	(17,477,844.20)	(17,596,060.07)	(17,692,593.27)
Taxes, other than income	(2,250,581.09)	(2,407,991.33)	(2,530,803.21)	(2,481,439.37)
Total Operating Expenses	(111,334,900.94)	(113,685,975.04)	(116,506,748.93)	(111,557,327.06)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	39,055,477.40	53,406,050.69	52,546,019.20	37,052,984.55
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	97,924.23	(560,841.25)	685,831.19	1,969,698.93
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(6,457,323.92)	(6,639,931.21)	(6,368,498.50)	(6,180,853.03)
Interest Expense with Affiliate	0.00	0.00	0.00	0.00
Income (Loss) from Continuing Operations Before Income Taxes	32,696,077.71	46,205,278.23	46,863,351.89	32,841,830.45
Income Taxes	(12,320,054.88)	(17,817,915.22)	(17,339,135.95)	(12,437,103.09)
Income (Loss) from Continuing Operations After Income Taxes	20,376,022.83	28,387,363.01	29,524,215.94	20,404,727.36
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	20,376,022.83	28,387,363.01	29,524,215.94	20,404,727.36

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 04/30/15	Month Ended 05/31/15	Month Ended 06/30/15	Month Ended 07/31/15
Operating Revenues				
Utility revenues	118,337,313.30	131,938,725.34	141,589,269.79	156,330,751.90
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	125,846.25	1,430,579.19	2,804,674.40	3,593,694.25
Total Operating Revenues	118,463,159.55	133,369,304.53	144,393,944.19	159,924,446.15
Operating Expenses				
Fuel	(36,393,540.96)	(45,742,920.96)	(49,210,446.24)	(53,137,707.89)
Energy purchases	(1,801,568.26)	(1,358,214.49)	(1,337,201.80)	(1,429,675.77)
Energy purchases from affiliate	(5,259,744.02)	(2,098,603.76)	(1,041,879.61)	(628,074.56)
Other operation and maintenance	(41,091,495.56)	(33,079,601.27)	(34,524,142.26)	(34,744,342.15)
Depreciation	(17,726,483.16)	(17,906,934.82)	(18,554,370.38)	(19,045,814.23)
Taxes, other than income	(2,208,874.43)	(2,410,396.25)	(2,396,453.31)	(2,386,470.05)
Total Operating Expenses	(104,481,706.39)	(102,596,671.55)	(107,064,493.60)	(111,372,084.65)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	13,981,453.16	30,772,632.98	37,329,450.59	48,552,361.50
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	(50,335.91)	(162,760.24)	38,884.56	(341,013.12)
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(6,392,702.54)	(6,418,013.69)	(6,464,418.42)	(6,572,080.21)
Interest Expense with Affiliate	0.00	(247.06)	(750.94)	0.00
Income (Loss) from Continuing Operations Before Income Taxes	7,538,414.71	24,191,611.99	30,903,165.79	41,639,268.17
Income Taxes	(2,778,593.33)	(9,256,687.10)	(11,621,211.79)	(16,043,825.31)
Income (Loss) from Continuing Operations After Income Taxes	4,759,821.38	14,934,924.89	19,281,954.00	25,595,442.86
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	4,759,821.38	14,934,924.89	19,281,954.00	25,595,442.86

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 08/31/15	Month Ended 09/30/15	Month Ended 10/31/15	Month Ended 11/30/15
Operating Revenues				
Utility revenues	153,906,829.54	141,812,947.57	125,140,729.06	124,540,950.10
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	2,865,630.91	2,485,385.35	701,138.14	797,512.84
Total Operating Revenues	156,772,460.45	144,298,332.92	125,841,867.20	125,338,462.94
Operating Expenses				
Fuel	(49,512,762.80)	(43,787,619.90)	(33,477,097.31)	(34,334,435.66)
Energy purchases	(1,560,926.13)	(1,615,060.82)	(1,613,691.52)	(1,340,745.57)
Energy purchases from affiliate	(722,128.39)	(887,097.40)	(1,706,770.13)	(2,177,205.05)
Other operation and maintenance	(35,289,402.77)	(38,424,395.10)	(40,112,071.12)	(37,802,559.86)
Depreciation	(18,893,748.58)	(18,803,070.11)	(18,697,922.16)	(18,737,016.10)
Taxes, other than income	(2,394,194.65)	(2,376,393.04)	(2,416,351.21)	(2,381,364.51)
Total Operating Expenses	(108,373,163.32)	(105,893,636.37)	(98,023,903.45)	(96,773,326.75)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	48,399,297.13	38,404,696.55	27,817,963.75	28,565,136.19
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	(216,867.16)	(112,870.26)	(174,860.23)	(1,054,350.62)
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(6,419,975.26)	(6,604,509.98)	(8,246,147.82)	(7,771,407.53)
Interest Expense with Affiliate	0.00	(171.83)	0.00	0.00
Income (Loss) from Continuing Operations Before Income Taxes	41,762,454.71	31,687,144.48	19,396,955.70	19,739,378.04
Income Taxes	(15,943,686.25)	(11,273,120.31)	(7,479,985.93)	(7,524,768.05)
Income (Loss) from Continuing Operations After Income Taxes	25,818,768.46	20,414,024.17	11,916,969.77	12,214,609.99
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	25,818,768.46	20,414,024.17	11,916,969.77	12,214,609.99

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 12/31/15	Month Ended 01/31/16	Month Ended 02/29/16	Month Ended 03/31/16
Operating Revenues				
Utility revenues	133,508,959.79	171,248,823.78	150,196,491.41	129,409,643.99
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	2,016,802.30	281,203.70	65,990.06	1,340,745.47
Total Operating Revenues	135,525,762.09	171,530,027.48	150,262,481.47	130,750,389.46
Operating Expenses				
Fuel	(37,476,547.40)	(47,897,518.70)	(38,575,326.48)	(33,490,288.06)
Energy purchases	(1,548,720.97)	(1,358,624.43)	(1,424,813.95)	(1,302,203.26)
Energy purchases from affiliate	(828,576.87)	(4,451,935.48)	(3,744,528.18)	(2,976,139.76)
Other operation and maintenance	(35,295,941.01)	(32,420,332.50)	(34,588,536.97)	(39,435,972.29)
Depreciation	(19,003,715.26)	(19,279,311.68)	(19,333,516.40)	(19,353,857.85)
Taxes, other than income	(2,350,091.67)	(2,380,042.56)	(2,483,299.06)	(2,525,886.98)
Total Operating Expenses	(96,503,593.18)	(107,787,765.35)	(100,150,021.04)	(99,084,348.20)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	39,022,168.91	63,742,262.13	50,112,460.43	31,666,041.26
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	(335,910.75)	(561,903.26)	(439,809.79)	(34,589.21)
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(7,803,831.42)	(7,881,445.15)	(7,803,988.07)	(7,830,292.73)
Interest Expense with Affiliate	0.00	(531.59)	0.00	0.00
Income (Loss) from Continuing Operations Before Income Taxes	30,882,426.74	55,298,382.13	41,868,662.57	23,801,159.32
Income Taxes	(10,598,595.80)	(21,357,220.66)	(16,133,059.75)	(8,477,636.78)
Income (Loss) from Continuing Operations After Income Taxes	20,283,830.94	33,941,161.47	25,735,602.82	15,323,522.54
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	20,283,830.94	33,941,161.47	25,735,602.82	15,323,522.54

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 04/30/16	Month Ended 05/31/16	Month Ended 06/30/16	Month Ended 07/31/16
Operating Revenues				
Utility revenues	126,209,209.65	127,231,243.15	150,819,267.07	161,428,663.83
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	868,396.12	1,491,664.00	1,312,407.67	1,217,014.49
Total Operating Revenues	127,077,605.77	128,722,907.15	152,131,674.74	162,645,678.32
Operating Expenses				
Fuel	(32,577,670.19)	(35,665,787.38)	(44,915,767.60)	(48,469,860.48)
Energy purchases	(1,489,321.06)	(1,641,832.81)	(1,457,057.73)	(1,740,051.77)
Energy purchases from affiliate	(3,240,643.09)	(594,316.06)	(1,473,842.52)	(1,365,674.51)
Other operation and maintenance	(40,319,147.28)	(33,305,664.61)	(32,781,781.40)	(35,636,271.43)
Depreciation	(19,353,188.51)	(19,359,133.71)	(19,405,656.83)	(19,456,507.13)
Taxes, other than income	(2,526,627.72)	(2,408,871.23)	(2,500,302.22)	(2,549,780.00)
Total Operating Expenses	(99,506,597.85)	(92,975,605.80)	(102,534,408.30)	(109,218,145.32)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	27,571,007.92	35,747,301.35	49,597,266.44	53,427,533.00
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	(336,948.91)	(202,761.65)	(178,142.33)	(358,839.40)
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(7,841,242.76)	(7,798,182.61)	(8,032,054.28)	(7,978,281.13)
Interest Expense with Affiliate	(634.22)	(375.95)	(133.06)	(59.93)
Income (Loss) from Continuing Operations Before Income Taxes	19,392,182.03	27,745,981.14	41,386,936.77	45,090,352.54
Income Taxes	(7,389,708.81)	(10,522,793.55)	(15,768,978.83)	(17,386,297.16)
Income (Loss) from Continuing Operations After Income Taxes	12,002,473.22	17,223,187.59	25,617,957.94	27,704,055.38
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	12,002,473.22	17,223,187.59	25,617,957.94	27,704,055.38

KU COMPANY
Income Statements by Month
Month Ended 08/31/14 through Month Ended 11/30/16
GAAP

	Month Ended 08/31/16	Month Ended 09/30/16	Month Ended 10/31/16	Month Ended 11/30/16
Operating Revenues				
Utility revenues	163,932,660.71	143,824,189.16	127,513,587.20	127,380,794.11
Retail and wholesale	0.00	0.00	0.00	0.00
Wholesale to affiliate	1,549,107.08	1,452,829.07	2,811,665.24	695,810.32
Total Operating Revenues	165,481,767.79	145,277,018.23	130,325,252.44	128,076,604.43
Operating Expenses				
Fuel	(49,878,587.16)	(42,126,070.40)	(38,514,296.04)	(34,894,140.30)
Energy purchases	(1,551,905.86)	(1,543,337.65)	(1,406,427.82)	(1,470,504.30)
Energy purchases from affiliate	(376,806.27)	(1,051,145.58)	(558,940.88)	(1,030,036.36)
Other operation and maintenance	(36,535,568.58)	(34,428,529.95)	(35,647,397.23)	(35,242,511.58)
Depreciation	(19,532,089.55)	(19,650,755.42)	(19,768,670.84)	(19,805,695.02)
Taxes, other than income	(2,560,583.42)	(2,517,386.79)	(2,567,312.58)	(2,524,047.51)
Total Operating Expenses	(110,435,540.84)	(101,317,225.79)	(98,463,045.39)	(94,966,935.07)
Loss on Impairment	0.00	0.00	0.00	0.00
Operating Income	55,046,226.95	43,959,792.44	31,862,207.05	33,109,669.36
Derivative (Loss) Gain	0.00	0.00	0.00	0.00
Other Income (Expense) - net	146,888.79	(1,368,014.29)	(205,801.34)	(204,697.27)
Other-Than-Temporary Impairments	0.00	0.00	0.00	0.00
Interest Expense	(8,041,658.89)	(8,394,345.02)	(8,008,360.11)	(7,898,036.20)
Interest Expense with Affiliate	(194.09)	(94.72)	0.00	0.00
Income (Loss) from Continuing Operations Before Income Taxes	47,151,262.76	34,197,338.41	23,648,045.60	25,006,935.89
Income Taxes	(18,262,202.08)	(12,741,413.61)	(9,246,457.24)	(9,573,848.10)
Income (Loss) from Continuing Operations After Income Taxes	28,889,060.68	21,455,924.80	14,401,588.36	15,433,087.79
Income (Loss) from Discontinued Operations (net of income taxes)	0.00	0.00	0.00	0.00
Net Income (Loss)	28,889,060.68	21,455,924.80	14,401,588.36	15,433,087.79

Kentucky Utilities Company
Comparative Balance Sheets as of July 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,388,184,840.31	$ 7,546,439,527.86
Less: Reserves for Depreciation and Amortization	2,735,051,447.44	2,582,536,354.47
Total	5,653,133,392.87	4,963,903,173.39
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,720.15	971,720.15
Total	1,221,720.15	1,221,720.15
Current and Accrued Assets		
Cash	4,102,550.26	3,678,412.71
Special Deposits	-	-
Temporary Cash Investments	4,727,101.98	1,683,875.35
Accounts Receivable-Less Reserve	224,789,075.48	216,912,187.99
Accounts Receivable from Associated Companies	14,496,773.72	-
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	76,966,456.94	85,875,784.85
Plant Materials and Operating Supplies	37,081,214.15	36,772,271.29
Stores Expense	10,429,471.45	10,590,643.54
Emission Allowances	211,105.35	268,233.65
Prepayments	9,605,598.16	9,916,145.50
Miscellaneous Current and Accrued Assets	867,901.15	42,620,881.45
Total	383,277,248.64	408,318,436.33
Deferred Debits and Other		
Unamortized Debt Expense	19,128,438.00	18,269,567.30
Unamortized Loss on Bonds	9,547,793.14	10,820,989.20
Accumulated Deferred Income Taxes	186,130,110.02	161,844,971.87
Deferred Regulatory Assets	225,388,098.13	273,263,406.90
Other Deferred Debits	46,620,825.19	45,207,053.67
Total	486,815,264.48	509,405,988.94
Total Assets	$ 6,524,447,626.14	$ 5,882,849,318.81

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	538,858,083.00	407,858,083.00
Other Comprehensive Income	(1,265,893.12)	(874,418.63)
Retained Earnings	1,706,987,458.38	1,627,136,469.19
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,552,398,336.95	2,341,938,822.25
Other Long-Term Debt	2,090,475,834.94	1,841,597,373.75
Pollution Control Bonds	-	-
First Mortgage Bonds	-	-
Advances from Associated Companies	-	-
Total Long-Term Debt	2,090,475,834.94	1,841,597,373.75
Total Capitalization	4,642,874,171.89	4,183,536,196.00
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	159,990,476.78	162,977,045.82
Accounts Payable	149,800,123.83	163,473,167.34
Accounts Payable to Associated Companies	30,029,038.19	20,974,512.99
Customer Deposits	26,565,323.59	25,090,013.98
Taxes Accrued	18,189,856.62	27,752,202.39
Interest Accrued	17,499,174.62	15,040,778.66
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	22,851,712.55	19,388,283.60
Total	424,925,706.18	434,696,004.78
Deferred Credits and Other		
Accumulated Deferred Income Taxes	932,141,612.91	818,243,233.38
Investment Tax Credit	95,644,833.57	97,516,092.82
Regulatory Liabilities	149,187,106.48	146,445,827.26
Customer Advances for Construction	2,555,110.15	2,886,562.21
Asset Retirement Obligations	188,042,186.32	71,249,070.12
Other Deferred Credits	39,247,410.54	22,638,932.38
Miscellaneous Long-Term Liabilities	2,184,308.15	2,330,079.31
Accum Provision for Pension & Postretirement Benefits	47,645,179.95	103,307,320.55
Total	1,456,647,748.07	1,264,617,118.03
Total Liabilities and Stockholders Equity	$ 6,524,447,626.14	$ 5,882,849,318.81

August 21, 2014

Kentucky Utilities Company
Comparative Balance Sheets as of August 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,442,182,812.71	$ 7,602,291,314.61
Less: Reserves for Depreciation and Amortization	2,743,276,537.64	2,597,259,052.10
Total	5,698,906,275.07	5,005,032,262.51
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,720.15	971,720.15
Total	1,221,720.15	1,221,720.15
Current and Accrued Assets		
Cash	6,516,061.00	4,209,983.35
Special Deposits	-	-
Temporary Cash Investments	20,113,465.97	593,144.52
Accounts Receivable-Less Reserve	220,942,711.28	214,443,511.65
Accounts Receivable from Associated Companies	38,458.83	1,266,101.62
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	76,223,169.46	86,006,764.02
Plant Materials and Operating Supplies	37,605,424.83	36,844,726.54
Stores Expense	10,521,211.00	10,400,307.80
Emission Allowances	199,125.88	261,139.76
Prepayments	8,564,228.10	8,884,822.01
Miscellaneous Current and Accrued Assets	23,617.75	45,987,773.40
Total	380,747,474.10	408,898,274.67
Deferred Debits and Other		
Unamortized Debt Expense	18,993,858.31	18,144,149.38
Unamortized Loss on Bonds	9,498,569.00	10,770,551.65
Accumulated Deferred Income Taxes	185,954,013.81	172,090,260.28
Deferred Regulatory Assets	231,198,240.09	272,842,716.10
Other Deferred Debits	46,759,023.56	45,319,386.16
Total	492,403,704.77	519,167,063.57
Total Assets	$ 6,573,279,174.09	$ 5,934,319,320.90

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	538,858,083.00	407,858,083.00
Other Comprehensive Income	(1,190,493.12)	(890,398.63)
Retained Earnings	1,703,903,664.42	1,622,045,183.39
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,549,389,942.99	2,336,831,556.45
Other Long-Term Debt	2,090,535,062.43	1,841,650,311.25
Pollution Control Bonds	-	-
First Mortgage Bonds	-	-
Advances from Associated Companies	-	-
Total Long-Term Debt	2,090,535,062.43	1,841,650,311.25
Total Capitalization	4,639,925,005.42	4,178,481,867.70
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	129,990,799.69	124,993,822.21
Accounts Payable	157,963,663.17	186,638,565.51
Accounts Payable to Associated Companies	30,349,865.34	25,904,131.80
Customer Deposits	26,702,517.05	25,233,454.04
Taxes Accrued	42,535,477.93	40,836,133.37
Interest Accrued	23,492,375.45	20,078,433.77
Dividends Declared	26,000,000.00	28,000,000.00
Miscellaneous Current and Accrued Liabilities	25,653,319.63	20,148,685.41
Total	462,688,018.26	471,833,226.11
Deferred Credits and Other		
Accumulated Deferred Income Taxes	933,079,260.43	832,826,490.68
Investment Tax Credit	95,488,895.57	97,360,154.82
Regulatory Liabilities	141,890,412.96	147,861,892.45
Customer Advances for Construction	2,472,128.20	2,893,849.82
Asset Retirement Obligations	207,759,772.91	71,514,133.69
Other Deferred Credits	40,153,748.09	25,918,296.99
Miscellaneous Long-Term Liabilities	2,184,308.15	2,330,079.31
Accum Provision for Pension & Postretirement Benefits	47,637,624.10	103,299,329.33
Total	1,470,666,150.41	1,284,004,227.09
Total Liabilities and Stockholders Equity	$ 6,573,279,174.09	$ 5,934,319,320.90

September 22, 2014

Kentucky Utilities Company
Comparative Balance Sheets as of September 30, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,505,152,985.66	$ 7,771,907,314.77
Less: Reserves for Depreciation and Amortization	2,759,570,567.13	2,609,774,022.77
Total	5,745,582,418.53	5,162,133,292.00
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,720.15	971,720.15
Total	1,221,720.15	1,221,720.15
Current and Accrued Assets		
Cash	6,648,756.51	5,503,776.02
Special Deposits	-	-
Temporary Cash Investments	15,196,783.86	3,576,310.91
Accounts Receivable-Less Reserve	204,323,725.11	206,498,307.63
Accounts Receivable from Associated Companies	3,454,348.87	10,466,068.64
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	77,029,464.27	87,217,841.01
Plant Materials and Operating Supplies	37,926,559.97	36,871,038.58
Stores Expense	10,459,554.57	10,365,029.17
Emission Allowances	192,041.66	254,174.15
Prepayments	8,805,530.50	8,891,640.34
Miscellaneous Current and Accrued Assets	2,804,902.73	-
Total	366,841,668.05	369,644,186.45
Deferred Debits and Other		
Unamortized Debt Expense	18,816,119.96	17,968,664.92
Unamortized Loss on Bonds	9,450,932.73	10,720,114.10
Accumulated Deferred Income Taxes	189,224,915.51	216,459,808.15
Deferred Regulatory Assets	234,877,907.09	273,196,453.02
Other Deferred Debits	47,113,280.86	44,872,420.63
Total	499,483,156.15	563,217,460.82
Total Assets	$ 6,613,128,962.88	$ 6,096,216,659.42

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	538,858,083.00	407,858,083.00
Other Comprehensive Income	(1,225,421.72)	(887,729.36)
Retained Earnings	1,718,028,978.65	1,641,112,518.63
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,563,480,328.62	2,355,901,560.96
Other Long-Term Debt	2,090,592,379.36	1,841,703,248.72
Pollution Control Bonds	-	-
First Mortgage Bonds	-	-
Advances from Associated Companies	-	-
Total Long-Term Debt	2,090,592,379.36	1,841,703,248.72
Total Capitalization	4,654,072,707.98	4,197,604,809.68
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	129,990,812.67	139,993,922.22
Accounts Payable	174,954,437.95	161,843,132.26
Accounts Payable to Associated Companies	29,400,562.53	24,079,178.28
Customer Deposits	26,738,302.05	25,216,106.35
Taxes Accrued	20,787,140.27	64,443,713.80
Interest Accrued	29,530,477.53	25,110,992.13
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	26,738,515.85	30,150,072.54
Total	438,140,248.85	470,837,117.58
Deferred Credits and Other		
Accumulated Deferred Income Taxes	975,682,757.53	874,381,772.01
Investment Tax Credit	95,332,955.57	97,204,216.82
Regulatory Liabilities	149,790,701.38	144,365,924.87
Customer Advances for Construction	2,465,621.82	2,900,950.04
Asset Retirement Obligations	208,595,134.24	176,668,429.33
Other Deferred Credits	40,389,078.66	27,531,484.34
Miscellaneous Long-Term Liabilities	1,672,390.37	2,168,625.39
Accum Provision for Pension & Postretirement Benefits	46,987,366.48	102,553,329.33
Total	1,520,916,006.05	1,427,774,732.13
Total Liabilities and Stockholders Equity	$ 6,613,128,962.88	$ 6,096,216,659.39

October 24, 2014

Kentucky Utilities Company
Comparative Balance Sheets as of October 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.......................................	$ 8,555,402,692.50	$ 7,864,940,823.69
Less: Reserves for Depreciation and Amortization......	2,772,420,074.90	2,623,281,988.81
Total...	5,782,982,617.60	5,241,658,834.88
Investments		
Electric Energy, Inc..	-	-
Ohio Valley Electric Company....................................	250,000.00	250,000.00
Nonutility Property-Less Reserve................................	971,720.15	971,720.15
Total...	1,221,720.15	1,221,720.15
Current and Accrued Assets		
Cash..	3,957,771.15	3,002,290.12
Special Deposits...	-	-
Temporary Cash Investments......................................	8,951,092.09	2,451,488.31
Accounts Receivable-Less Reserve.............................	190,519,269.94	187,169,962.85
Accounts Receivable from Associated Companies......	23,154.07	5,542.29
Notes Receivable from Associated Companies...........	-	-
Materials and Supplies-At Average Cost		
Fuel..	87,809,179.21	82,081,535.91
Plant Materials and Operating Supplies....................	37,934,690.18	36,765,618.20
Stores Expense..	10,151,022.64	10,287,225.77
Emission Allowances..	182,719.63	245,185.39
Prepayments..	7,495,599.51	7,633,902.57
Miscellaneous Current and Accrued Assets................	2,359,144.20	-
Total...	349,383,642.62	329,642,751.41
Deferred Debits and Other		
Unamortized Debt Expense...	18,844,654.84	17,785,530.11
Unamortized Loss on Bonds.......................................	9,704,965.31	10,669,676.55
Accumulated Deferred Income Taxes.........................	189,224,915.53	216,459,808.15
Deferred Regulatory Assets...	244,052,150.26	273,967,271.51
Other Deferred Debits...	47,265,516.62	47,152,531.28
Total...	509,092,202.56	566,034,817.60
Total Assets	$ 6,642,680,182.93	$ 6,138,558,124.04

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense...	321,288.87	321,288.87
Paid-In Capital..	538,858,083.00	407,858,083.00
Other Comprehensive Income..	(1,225,421.72)	(903,709.36)
Retained Earnings..	1,729,998,960.60	1,655,558,576.18
Unappropriated Undistributed Subsidiary Earnings............	-	-
Total Proprietary Capital..	2,575,450,310.57	2,370,331,638.51
Other Long-Term Debt...	2,090,651,606.86	1,841,756,186.25
Pollution Control Bonds...	-	-
First Mortgage Bonds...	-	-
Advances from Associated Companies...............................	-	-
Total Long-Term Debt..	2,090,651,606.86	1,841,756,186.25
Total Capitalization..	4,666,101,917.43	4,212,087,824.76
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.......................	-	-
Notes Payable...	129,990,476.90	126,995,217.49
Accounts Payable...	169,385,746.07	189,731,495.70
Accounts Payable to Associated Companies.......................	28,114,789.24	24,233,402.83
Customer Deposits...	26,981,975.38	25,399,240.53
Taxes Accrued..	26,584,074.43	65,483,799.59
Interest Accrued...	35,530,696.65	30,151,718.88
Dividends Declared..	-	-
Miscellaneous Current and Accrued Liabilities..................	33,055,446.01	32,309,372.09
Total...	449,643,204.68	494,304,247.11
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	975,682,757.54	874,387,988.23
Investment Tax Credit..	95,177,017.57	97,048,278.82
Regulatory Liabilities...	153,787,656.01	141,253,116.79
Customer Advances for Construction..................................	2,246,299.24	2,881,646.91
Asset Retirement Obligations...	209,430,470.42	177,405,177.73
Other Deferred Credits...	41,446,726.18	34,322,097.65
Miscellaneous Long-Term Liabilities..................................	2,184,308.15	2,330,079.31
Accum Provision for Pension & Postretirement Benefits.....	46,979,825.71	102,537,666.73
Total...	1,526,935,060.82	1,432,166,052.17
Total Liabilities and Stockholders Equity................................	$ 6,642,680,182.93	$ 6,138,558,124.04

November 21, 2014

Kentucky Utilities Company
Comparative Balance Sheets as of November 30, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,598,961,464.32	$ 7,968,334,444.84
Less: Reserves for Depreciation and Amortization	2,784,835,792.14	2,635,827,834.70
Total	5,814,125,672.18	5,332,506,610.14
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,720.15	971,720.15
Total	1,221,720.15	1,221,720.15
Current and Accrued Assets		
Cash	10,156,826.59	2,134,886.63
Special Deposits	-	-
Temporary Cash Investments	12,300,587.98	49,597,834.82
Accounts Receivable-Less Reserve	207,176,372.31	203,855,900.70
Accounts Receivable from Associated Companies	23,154.07	-
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	93,515,847.19	85,090,968.85
Plant Materials and Operating Supplies	38,060,211.44	36,279,459.57
Stores Expense	10,267,366.59	10,216,955.22
Emission Allowances	169,828.50	241,690.98
Prepayments	6,259,162.09	6,591,999.64
Miscellaneous Current and Accrued Assets	311,056.62	-
Total	378,240,413.38	394,009,696.41
Deferred Debits and Other		
Unamortized Debt Expense	18,762,549.24	19,905,693.17
Unamortized Loss on Bonds	9,648,786.62	10,619,239.00
Accumulated Deferred Income Taxes	189,224,915.53	216,459,808.15
Deferred Regulatory Assets	258,030,499.78	274,562,960.22
Other Deferred Debits	46,310,646.34	44,928,073.97
Total	521,977,397.51	566,475,774.51
Total Assets	$ 6,715,565,203.22	$ 6,294,213,801.21

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	538,858,083.00	407,858,083.00
Other Comprehensive Income	(1,224,221.72)	(919,688.36)
Retained Earnings	1,708,628,865.93	1,632,180,817.11
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,554,081,415.90	2,346,937,900.44
Other Long-Term Debt	1,840,708,923.79	2,090,011,623.75
Total Long-Term Debt	1,840,708,923.79	2,090,011,623.75
Total Capitalization	4,394,790,339.69	4,436,949,524.19
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	446,844,639.42	(0.01)
Accounts Payable	179,183,657.47	230,596,857.17
Accounts Payable to Associated Companies	31,528,242.44	22,911,944.16
Customer Deposits	27,047,613.43	25,511,258.67
Taxes Accrued	26,441,711.12	71,900,110.97
Interest Accrued	6,398,638.38	6,307,174.09
Dividends Declared	36,000,000.00	41,000,000.00
Miscellaneous Current and Accrued Liabilities	44,257,165.66	20,083,687.61
Total	797,701,667.92	418,311,032.66
Deferred Credits and Other		
Accumulated Deferred Income Taxes	975,682,290.74	874,394,204.06
Investment Tax Credit	95,021,079.57	96,892,340.82
Regulatory Liabilities	149,620,265.42	145,195,339.58
Customer Advances for Construction	2,232,463.26	2,860,452.39
Asset Retirement Obligations	210,171,982.88	178,145,089.44
Other Deferred Credits	41,188,392.33	36,605,732.02
Miscellaneous Long-Term Liabilities	2,184,308.15	2,330,079.31
Accum Provision for Pension & Postretirement Benefits	46,972,413.26	102,530,006.74
Total	1,523,073,195.61	1,438,953,244.36
Total Liabilities and Stockholders Equity	$ 6,715,565,203.22	$ 6,294,213,801.21

December 19, 2014

Kentucky Utilities Company
Comparative Balance Sheets as of December 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,667,708,179.24	$ 8,108,605,484.28
Less: Reserves for Depreciation and Amortization	2,798,968,737.30	2,647,410,912.79
Total	5,868,739,441.94	5,461,194,571.49
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	7,069,896.19	5,034,445.07
Special Deposits	-	-
Temporary Cash Investments	4,066,766.38	15,653,516.82
Accounts Receivable-Less Reserve	222,270,038.81	225,296,702.84
Accounts Receivable from Associated Companies	59,765,612.63	65,306.45
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	99,282,055.68	77,808,311.92
Plant Materials and Operating Supplies	38,655,516.05	36,405,242.77
Stores Expense	10,574,015.53	10,213,703.34
Emission Allowances	158,872.09	293,509.46
Prepayments	7,629,373.84	5,913,624.68
Miscellaneous Current and Accrued Assets	-	-
Total	449,472,147.20	376,684,363.35
Deferred Debits and Other		
Unamortized Debt Expense	18,614,826.72	19,877,250.93
Unamortized Loss on Bonds	9,590,735.30	9,638,315.65
Accumulated Deferred Income Taxes	221,690,913.50	208,306,280.03
Deferred Regulatory Assets	329,468,702.21	237,578,508.08
Other Deferred Debits	44,685,393.69	41,336,647.47
Total	624,050,571.42	516,737,002.16
Total Assets	$ 6,943,483,473.66	$ 6,355,837,657.15

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	472,858,083.00
Other Comprehensive Income	(1,232,509.32)	(917,020.08)
Retained Earnings	1,728,986,178.85	1,657,535,909.36
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,599,430,441.22	2,437,295,660.97
Other Long-Term Debt	2,090,768,151.28	2,090,069,568.21
Total Long-Term Debt	2,090,768,151.28	2,090,069,568.21
Total Capitalization	4,690,198,592.50	4,527,365,229.18
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	235,592,322.03	149,967,365.54
Accounts Payable	153,042,157.99	172,652,307.41
Accounts Payable to Associated Companies	46,590,075.29	25,347,064.53
Customer Deposits	27,255,893.31	25,654,974.53
Taxes Accrued	13,974,039.11	32,514,049.65
Interest Accrued	11,624,315.19	11,524,331.28
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	58,617,072.54	21,425,638.87
Total	546,695,875.46	439,085,731.81
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,104,287,220.74	863,550,091.66
Investment Tax Credit	94,865,139.57	96,736,399.57
Regulatory Liabilities	136,098,871.38	150,443,178.54
Customer Advances for Construction	2,218,445.28	2,882,357.12
Asset Retirement Obligations	210,966,863.53	178,860,881.13
Other Deferred Credits	38,495,003.59	34,563,218.39
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	117,607,469.93	60,166,261.60
Total	1,706,589,005.70	1,389,386,696.16
Total Liabilities and Stockholders Equity	$ 6,943,483,473.66	$ 6,355,837,657.15

January 27, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of January 31, 2015 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,697,739,548.30	$ 8,148,273,615.21
Less: Reserves for Depreciation and Amortization	2,815,155,222.08	2,662,547,453.56
Total	5,882,584,326.22	5,485,726,161.65
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	7,329,970.34	4,162,753.34
Special Deposits	-	-
Temporary Cash Investments	2,279,607.55	3,973,912.13
Accounts Receivable-Less Reserve	254,786,002.06	265,955,690.78
Accounts Receivable from Associated Companies	44,594,689.15	47,634.57
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	92,522,835.95	65,918,660.83
Plant Materials and Operating Supplies	38,415,753.80	36,295,825.18
Stores Expense	10,218,047.74	10,251,642.90
Emission Allowances	157,035.04	281,871.35
Prepayments	9,071,291.61	6,780,028.40
Miscellaneous Current and Accrued Assets	-	-
Total	459,375,233.24	393,668,019.48
Deferred Debits and Other		
Unamortized Debt Expense	18,428,635.08	19,719,960.26
Unamortized Loss on Bonds	9,532,683.94	9,544,316.08
Accumulated Deferred Income Taxes	221,690,913.49	208,306,280.02
Deferred Regulatory Assets	374,678,917.59	237,239,968.71
Other Deferred Debits	45,575,949.36	42,458,350.33
Total	669,907,099.46	517,268,875.40
Total Assets	$ 7,013,087,972.02	$ 6,397,884,776.68

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	472,858,083.00
Other Comprehensive Income	(1,232,509.32)	(917,020.08)
Retained Earnings	1,757,355,088.50	1,690,988,897.99
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,627,799,350.87	2,470,748,649.60
Other Long-Term Debt	2,090,827,378.77	2,090,127,512.67
Total Long-Term Debt	2,090,827,378.77	2,090,127,512.67
Total Capitalization	4,718,626,729.64	4,560,876,162.27
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	290,967,792.63	106,989,663.32
Accounts Payable	113,754,496.22	176,791,286.08
Accounts Payable to Associated Companies	32,165,906.55	42,269,161.77
Customer Deposits	27,178,621.48	26,282,053.02
Taxes Accrued	9,204,464.82	54,603,013.09
Interest Accrued	17,618,885.17	17,513,295.99
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	106,699,730.46	21,568,877.09
Total	597,589,897.33	446,017,350.36
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,104,287,220.73	863,550,091.66
Investment Tax Credit	94,709,201.57	96,580,461.57
Regulatory Liabilities	138,973,112.29	148,429,339.37
Customer Advances for Construction	2,180,887.96	2,857,003.43
Asset Retirement Obligations	211,815,663.68	182,382,950.44
Other Deferred Credits	39,965,154.70	37,048,389.30
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	102,890,112.44	57,958,720.13
Total	1,696,871,345.05	1,390,991,264.05
Total Liabilities and Stockholders Equity	$ 7,013,087,972.02	$ 6,397,884,776.68

February 20, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of February 28, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,724,392,698.03	$ 8,171,709,279.77
Less: Reserves for Depreciation and Amortization	2,822,254,109.94	2,670,483,180.50
Total	5,902,138,588.09	5,501,226,099.27
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	6,340,684.46	5,693,335.41
Special Deposits	-	-
Temporary Cash Investments	8,033,998.95	3,836,274.33
Accounts Receivable-Less Reserve	269,107,973.17	263,321,899.88
Accounts Receivable from Associated Companies	33,685,035.94	96,726.29
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	85,358,312.27	61,587,064.68
Plant Materials and Operating Supplies	38,692,862.20	36,297,178.90
Stores Expense	10,328,880.13	10,377,547.85
Emission Allowances	155,398.87	270,761.53
Prepayments	9,259,755.88	7,858,465.65
Miscellaneous Current and Accrued Assets	-	-
Total	460,962,901.87	389,339,254.52
Deferred Debits and Other		
Unamortized Debt Expense	18,260,456.30	19,648,807.12
Unamortized Loss on Bonds	9,480,250.51	9,500,679.48
Accumulated Deferred Income Taxes	230,401,542.17	208,306,280.02
Deferred Regulatory Assets	345,565,960.90	239,063,991.91
Other Deferred Debits	43,873,804.19	42,388,822.77
Total	647,582,014.07	518,908,581.30
Total Assets	$ 7,011,904,817.13	$ 6,410,695,655.24

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	472,858,083.00
Other Comprehensive Income	(1,232,509.32)	(917,020.08)
Retained Earnings	1,756,861,620.75	1,679,049,672.53
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,627,305,883.12	2,458,809,424.14
Other Long-Term Debt	2,090,880,874.57	2,090,185,457.13
Total Long-Term Debt	2,090,880,874.57	2,090,185,457.13
Total Capitalization	4,718,186,757.69	4,548,994,881.27
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	264,890,745.65	116,991,122.76
Accounts Payable	112,807,295.69	141,927,862.70
Accounts Payable to Associated Companies	35,212,922.28	28,605,084.56
Customer Deposits	27,274,071.04	26,505,891.28
Taxes Accrued	10,632,864.28	72,061,491.30
Interest Accrued	23,610,871.48	23,502,190.70
Dividends Declared	30,000,000.00	37,000,000.00
Miscellaneous Current and Accrued Liabilities	74,445,941.64	20,654,505.41
Total	578,874,712.06	467,248,148.71
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,119,204,755.90	863,550,091.66
Investment Tax Credit	94,553,263.57	96,424,523.57
Regulatory Liabilities	140,427,150.92	149,868,227.76
Customer Advances for Construction	2,160,348.44	2,799,421.67
Asset Retirement Obligations	212,661,999.12	183,104,125.61
Other Deferred Credits	40,913,399.62	38,570,672.94
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	102,872,438.13	57,951,253.90
Total	1,714,843,347.38	1,394,452,625.26
Total Liabilities and Stockholders Equity	$ 7,011,904,817.13	$ 6,410,695,655.24

March 20, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of March 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,756,154,281.14	$ 8,216,428,762.71
Less: Reserves for Depreciation and Amortization	2,823,695,881.95	2,685,642,385.46
Total	5,932,458,399.19	5,530,786,377.25
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	8,838,869.93	13,988,193.58
Special Deposits	-	-
Temporary Cash Investments	13,817,579.95	6,526,762.59
Accounts Receivable-Less Reserve	229,353,596.80	234,614,416.41
Accounts Receivable from Associated Companies	3,780.56	104,023.62
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	85,168,242.89	68,042,015.03
Plant Materials and Operating Supplies	38,255,517.55	36,520,773.36
Stores Expense	10,301,235.88	10,412,174.27
Emission Allowances	153,516.84	257,629.51
Prepayments	7,073,562.72	6,607,342.06
Miscellaneous Current and Accrued Assets	156.46	545.80
Total	392,966,059.58	377,073,876.23
Deferred Debits and Other		
Unamortized Debt Expense	18,074,299.24	19,458,033.91
Unamortized Loss on Bonds	9,422,199.19	9,456,812.88
Accumulated Deferred Income Taxes	233,812,122.48	207,130,718.65
Deferred Regulatory Assets	362,674,664.66	237,346,728.94
Other Deferred Debits	46,474,675.39	42,644,289.33
Total	670,457,960.96	516,036,583.71
Total Assets	$ 6,997,103,732.83	$ 6,425,118,557.34

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	512,858,083.00
Other Comprehensive Income	(2,137,644.72)	(1,100,211.94)
Retained Earnings	1,777,247,894.75	1,696,831,333.48
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,646,787,021.72	2,516,407,893.23
Other Long-Term Debt	2,090,940,102.07	2,090,243,401.59
Total Long-Term Debt	2,090,940,102.07	2,090,243,401.59
Total Capitalization	4,737,727,123.79	4,606,651,294.82
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	192,947,747.17	109,989,488.90
Accounts Payable	120,407,085.40	143,991,560.45
Accounts Payable to Associated Companies	33,345,532.72	41,058,992.36
Customer Deposits	27,238,382.69	26,408,105.14
Taxes Accrued	13,323,031.00	21,284,746.78
Interest Accrued	29,640,399.19	29,518,049.69
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	87,544,924.73	21,642,548.72
Total	504,447,102.90	393,893,492.04
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,160,095,669.43	897,459,039.16
Investment Tax Credit	94,403,589.57	96,268,585.57
Regulatory Liabilities	140,750,798.01	148,125,916.87
Customer Advances for Construction	2,148,289.69	2,776,231.23
Asset Retirement Obligations	213,517,919.65	183,868,940.67
Other Deferred Credits	39,752,928.60	36,645,808.23
Miscellaneous Long-Term Liabilities	2,189,595.08	1,660,089.01
Accum Provision for Pension & Postretirement Benefits	102,070,716.11	57,769,159.74
Total	1,754,929,506.14	1,424,573,770.48
Total Liabilities and Stockholders Equity	$ 6,997,103,732.83	$ 6,425,118,557.34

April 27, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of April 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.......................................	$ 8,785,148,966.75	$ 8,264,106,724.15
Less: Reserves for Depreciation and Amortization.......	2,829,095,375.74	2,696,668,323.11
Total...	5,956,053,591.01	5,567,438,401.04
Investments		
Electric Energy, Inc..	-	-
Ohio Valley Electric Company....................................	250,000.00	250,000.00
Nonutility Property-Less Reserve................................	971,313.10	971,720.15
Special Fund...	-	-
Total...	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash..	4,108,539.62	6,476,264.94
Special Deposits..	-	-
Temporary Cash Investments.......................................	3,348,985.91	3,800,169.01
Accounts Receivable-Less Reserve..............................	198,343,445.09	213,731,487.26
Accounts Receivable from Associated Companies........	176,601.56	-
Notes Receivable from Associated Companies...........	-	-
Materials and Supplies-At Average Cost		
Fuel...	91,058,972.11	82,546,525.13
Plant Materials and Operating Supplies.....................	38,623,349.94	36,018,416.95
Stores Expense...	10,218,182.51	10,419,460.21
Emission Allowances..	151,533.42	246,791.75
Prepayments..	10,488,582.86	6,132,068.30
Miscellaneous Current and Accrued Assets..................	-	-
Total...	356,518,193.02	359,371,183.55
Deferred Debits and Other		
Unamortized Debt Expense...	17,894,295.98	19,266,450.93
Unamortized Loss on Bonds..	9,366,020.49	9,412,946.28
Accumulated Deferred Income Taxes..........................	233,812,122.48	207,130,718.65
Deferred Regulatory Assets..	356,890,250.18	239,849,391.89
Other Deferred Debits..	47,257,428.47	42,983,143.04
Total...	665,220,117.60	518,642,650.79
Total Assets	$ 6,979,013,214.73	$ 6,446,673,955.53

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense..	321,288.87	321,288.87
Paid-In Capital...	563,858,083.00	512,858,083.00
Other Comprehensive Income..	(2,137,644.72)	(1,100,211.94)
Retained Earnings..	1,781,989,519.33	1,703,284,656.33
Unappropriated Undistributed Subsidiary Earnings.............	-	-
Total Proprietary Capital..	2,651,528,646.30	2,522,861,216.08
Other Long-Term Debt...	2,090,997,418.99	2,090,301,346.05
Total Long-Term Debt..	2,090,997,418.99	2,090,301,346.05
Total Capitalization..	4,742,526,065.29	4,613,162,562.13
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable..	150,011,667.76	81,988,576.40
Accounts Payable...	125,124,623.69	175,405,569.60
Accounts Payable to Associated Companies........................	40,537,871.10	39,653,784.23
Customer Deposits...	27,159,704.31	26,321,516.09
Taxes Accrued..	26,751,143.21	27,885,915.09
Interest Accrued...	35,638,144.07	35,518,177.37
Dividends Declared..	-	-
Miscellaneous Current and Accrued Liabilities...................	74,770,417.33	20,999,263.98
Total..	479,993,571.47	407,772,802.76
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	1,160,095,669.43	897,459,039.16
Investment Tax Credit...	94,249,739.57	96,112,647.57
Regulatory Liabilities..	140,159,458.64	145,926,575.77
Customer Advances for Construction..................................	2,134,453.70	2,762,027.84
Asset Retirement Obligations..	214,374,279.94	184,637,042.49
Other Deferred Credits...	41,204,207.16	38,895,358.98
Miscellaneous Long-Term Liabilities..................................	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits......	102,225,777.85	57,761,590.68
Total..	1,756,493,577.97	1,425,738,590.64
Total Liabilities and Stockholders Equity.................................	$ 6,979,013,214.73	$ 6,446,673,955.53

May 21, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of May 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,802,310,025.86	$ 8,315,925,441.23
Less: Reserves for Depreciation and Amortization	2,826,457,728.53	2,709,123,366.51
Total	5,975,852,297.33	5,606,802,074.72
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	8,206,612.86	3,929,762.92
Special Deposits	-	-
Temporary Cash Investments	531,207.78	247,472.37
Accounts Receivable-Less Reserve	200,113,862.31	214,162,056.86
Accounts Receivable from Associated Companies	-	-
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	95,073,396.34	84,536,426.84
Plant Materials and Operating Supplies	38,989,822.24	36,188,397.99
Stores Expense	10,048,613.24	10,415,302.75
Emission Allowances	149,894.71	234,785.04
Prepayments	9,575,108.78	9,232,279.23
Miscellaneous Current and Accrued Assets	-	-
Total	362,688,518.26	358,946,484.00
Deferred Debits and Other		
Unamortized Debt Expense	17,708,295.26	19,074,567.45
Unamortized Loss on Bonds	9,307,969.15	9,369,079.68
Accumulated Deferred Income Taxes	233,812,122.48	207,130,718.65
Deferred Regulatory Assets	351,325,173.81	237,506,964.68
Other Deferred Debits	47,619,002.58	43,247,881.53
Total	659,772,563.28	516,329,211.99
Total Assets	$ 6,999,534,691.97	$ 6,483,299,490.86

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	512,858,083.00
Other Comprehensive Income	(2,137,844.72)	(1,362,537.94)
Retained Earnings	1,745,905,990.86	1,669,674,641.04
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,615,444,917.83	2,488,988,874.79
Other Long-Term Debt	2,091,056,646.48	2,090,359,290.51
Total Long-Term Debt	2,091,056,646.48	2,090,359,290.51
Total Capitalization	4,706,501,564.31	4,579,348,165.30
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	192,912,103.55	124,994,419.83
Accounts Payable	117,464,116.94	169,564,805.72
Accounts Payable to Associated Companies	33,482,611.06	43,981,941.23
Customer Deposits	26,924,126.01	26,149,496.14
Taxes Accrued	38,312,996.05	39,423,096.12
Interest Accrued	6,456,040.61	6,296,471.93
Dividends Declared	51,000,000.00	49,000,000.00
Miscellaneous Current and Accrued Liabilities	68,197,447.56	19,154,940.46
Total	534,749,441.78	478,565,171.43
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,160,095,747.23	897,561,083.97
Investment Tax Credit	94,095,889.57	95,956,709.57
Regulatory Liabilities	140,511,751.93	145,419,561.82
Customer Advances for Construction	2,089,757.74	2,732,678.85
Asset Retirement Obligations	215,236,992.95	185,408,445.41
Other Deferred Credits	42,918,930.64	39,027,376.32
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	101,284,624.14	57,095,990.04
Total	1,758,283,685.88	1,425,386,154.13
Total Liabilities and Stockholders Equity	$ 6,999,534,691.97	$ 6,483,299,490.86

June 19, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of June 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,946,519,669.45	$ 8,345,204,982.30
Less: Reserves for Depreciation and Amortization	2,838,963,550.95	2,719,686,701.34
Total	6,107,556,118.50	5,625,518,280.96
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	5,007,417.03	7,317,940.84
Special Deposits	-	-
Temporary Cash Investments	1,029,502.66	10,620,748.76
Accounts Receivable-Less Reserve	217,142,773.94	232,569,741.63
Accounts Receivable from Associated Companies	2,475.15	24,425,689.02
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	96,160,683.02	77,378,356.67
Plant Materials and Operating Supplies	40,306,886.36	36,900,699.73
Stores Expense	10,102,105.59	10,517,576.25
Emission Allowances	148,114.70	222,852.18
Prepayments	11,365,369.57	8,121,065.58
Miscellaneous Current and Accrued Assets	132,969.39	-
Total	381,398,297.41	408,074,670.66
Deferred Debits and Other		
Unamortized Debt Expense	17,528,295.46	18,884,817.56
Unamortized Loss on Bonds	9,251,790.44	9,325,833.85
Accumulated Deferred Income Taxes	274,105,539.40	186,130,110.02
Deferred Regulatory Assets	323,925,739.71	225,620,434.87
Other Deferred Debits	47,686,435.41	46,541,899.64
Total	672,497,800.42	486,503,095.94
Total Assets	$ 7,162,673,529.43	$ 6,521,317,767.71

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	538,858,083.00
Other Comprehensive Income	(2,136,544.92)	(1,260,493.12)
Retained Earnings	1,765,169,748.05	1,688,441,917.92
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,634,709,974.82	2,533,858,196.49
Other Long-Term Debt	2,091,113,963.42	2,090,416,607.44
Total Long-Term Debt	2,091,113,963.42	2,090,416,607.44
Total Capitalization	4,725,823,938.24	4,624,274,803.93
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	226,951,047.46	174,979,425.00
Accounts Payable	132,208,798.33	157,764,224.48
Accounts Payable to Associated Companies	35,866,268.59	38,135,407.87
Customer Deposits	26,798,081.70	26,250,521.57
Taxes Accrued	28,167,428.29	14,150,403.13
Interest Accrued	11,749,580.88	11,466,586.86
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	50,358,707.86	21,825,478.15
Total	512,099,913.11	444,572,047.06
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,242,172,308.58	932,139,512.31
Investment Tax Credit	93,942,039.57	95,800,771.57
Regulatory Liabilities	147,086,307.88	147,233,402.14
Customer Advances for Construction	2,087,427.22	2,717,982.18
Asset Retirement Obligations	333,687,598.72	187,259,828.37
Other Deferred Credits	11,329,447.82	37,929,886.88
Miscellaneous Long-Term Liabilities	2,316,685.53	1,736,746.43
Accum Provision for Pension & Postretirement Benefits	92,127,862.76	47,652,786.84
Total	1,924,749,678.08	1,452,470,916.72
Total Liabilities and Stockholders Equity	$ 7,162,673,529.43	$ 6,521,317,767.71

July 27, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of July 31, 2015 & 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,969,491,437.29	$ 8,388,184,840.31
Less: Reserves for Depreciation and Amortization	2,854,118,353.29	2,735,051,447.44
Total	6,115,373,084.00	5,653,133,392.87
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	4,419,789.97	4,143,080.26
Special Deposits	-	-
Temporary Cash Investments	396,770.05	4,727,101.98
Accounts Receivable-Less Reserve	231,347,683.52	224,748,545.48
Accounts Receivable from Associated Companies	548.73	14,496,773.72
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	91,394,266.05	76,966,456.94
Plant Materials and Operating Supplies	40,241,376.39	37,081,214.15
Stores Expense	10,082,872.94	10,429,471.45
Emission Allowances	144,281.66	211,105.35
Prepayments	9,889,894.18	9,605,598.16
Miscellaneous Current and Accrued Assets	-	867,901.15
Total	387,917,483.49	383,277,248.64
Deferred Debits and Other		
Unamortized Debt Expense	17,236,365.70	19,128,438.00
Unamortized Loss on Bonds	9,193,739.16	9,547,793.14
Accumulated Deferred Income Taxes	274,105,539.40	186,130,110.02
Deferred Regulatory Assets	346,482,823.82	225,388,098.13
Other Deferred Debits	47,958,912.08	46,620,825.19
Total	694,977,380.16	486,815,264.48
Total Assets	$ 7,199,489,260.75	$ 6,524,447,626.14

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	538,858,083.00
Other Comprehensive Income	(2,136,544.92)	(1,265,893.12)
Retained Earnings	1,790,746,737.55	1,706,987,458.38
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,660,286,964.32	2,552,398,336.95
Other Long-Term Debt	2,091,173,190.91	2,090,475,834.94
Total Long-Term Debt	2,091,173,190.91	2,090,475,834.94
Total Capitalization	4,751,460,155.23	4,642,874,171.89
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	210,884,216.98	159,990,476.78
Accounts Payable	118,546,994.57	149,800,123.83
Accounts Payable to Associated Companies	28,777,148.32	30,029,038.19
Customer Deposits	26,491,600.15	26,565,323.59
Taxes Accrued	46,434,239.58	18,189,856.62
Interest Accrued	17,745,890.81	17,499,174.62
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	69,589,721.47	22,851,712.55
Total	518,469,811.88	424,925,706.18
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,242,172,308.58	932,141,612.91
Investment Tax Credit	93,788,189.57	95,644,833.57
Regulatory Liabilities	149,499,338.66	149,187,106.48
Customer Advances for Construction	2,051,489.08	2,555,110.15
Asset Retirement Obligations	335,063,348.55	188,042,186.32
Other Deferred Credits	12,824,781.34	39,247,410.54
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	92,109,846.18	47,645,179.95
Total	1,929,559,293.64	1,456,647,748.07
Total Liabilities and Stockholders Equity	$ 7,199,489,260.75	$ 6,524,447,626.14

August 21, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of August 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,984,536,417.11	$ 8,442,182,812.71
Less: Reserves for Depreciation and Amortization	2,854,322,446.77	2,743,276,537.64
Total	6,130,213,970.34	5,698,906,275.07
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	8,875,349.87	6,556,591.00
Special Deposits	-	-
Temporary Cash Investments	1,288,014.74	20,113,465.97
Accounts Receivable-Less Reserve	230,535,436.96	220,902,181.28
Accounts Receivable from Associated Companies	-	38,458.83
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	87,828,326.60	76,223,169.46
Plant Materials and Operating Supplies	40,529,934.08	37,605,424.83
Stores Expense	9,994,443.59	10,521,211.00
Emission Allowances	142,665.14	199,125.88
Prepayments	8,597,350.84	8,564,228.10
Miscellaneous Current and Accrued Assets	-	23,617.75
Total	387,791,521.82	380,747,474.10
Deferred Debits and Other		
Unamortized Debt Expense	17,052,758.57	18,993,858.31
Unamortized Loss on Bonds	9,135,687.78	9,498,569.00
Accumulated Deferred Income Taxes	274,729,581.86	185,954,013.81
Deferred Regulatory Assets	350,292,726.00	231,198,240.09
Other Deferred Debits	48,418,643.60	46,759,023.56
Total	699,629,397.81	492,403,704.77
Total Assets	$ 7,218,856,203.07	$ 6,573,279,174.09

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	538,858,083.00
Other Comprehensive Income	(2,136,744.92)	(1,190,493.12)
Retained Earnings	1,791,547,052.66	1,703,903,664.42
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,661,087,079.43	2,549,389,942.99
Other Long-Term Debt	2,091,232,418.40	2,090,535,062.43
Total Long-Term Debt	2,091,232,418.40	2,090,535,062.43
Total Capitalization	4,752,319,497.83	4,639,925,005.42
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	213,987,852.02	129,990,799.69
Accounts Payable	93,354,282.55	157,963,663.17
Accounts Payable to Associated Companies	24,538,008.58	30,349,865.34
Customer Deposits	26,302,851.05	26,702,517.05
Taxes Accrued	65,177,108.17	42,535,477.93
Interest Accrued	23,535,588.70	23,492,375.45
Dividends Declared	25,000,000.00	26,000,000.00
Miscellaneous Current and Accrued Liabilities	64,623,488.05	25,653,319.63
Total	536,519,179.12	462,688,018.26
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,242,420,535.88	933,079,260.43
Investment Tax Credit	93,634,339.57	95,488,895.57
Regulatory Liabilities	148,691,847.54	141,890,412.96
Customer Advances for Construction	2,050,145.10	2,472,128.20
Asset Retirement Obligations	336,372,286.18	207,759,772.91
Other Deferred Credits	13,616,132.38	40,153,748.09
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	91,182,247.79	47,637,624.10
Total	1,930,017,526.12	1,470,666,150.41
Total Liabilities and Stockholders Equity	$ 7,218,856,203.07	$ 6,573,279,174.09

September 22, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of September 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 8,976,329,597.43	$ 8,505,152,985.66
Less: Reserves for Depreciation and Amortization	2,814,559,410.99	2,759,570,567.13
Total	6,161,770,186.44	5,745,582,418.53
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	5,693,686.69	6,709,786.51
Special Deposits	-	-
Temporary Cash Investments	269,198,327.26	15,196,783.86
Accounts Receivable-Less Reserve	220,519,068.47	204,262,695.11
Accounts Receivable from Associated Companies	6,287.80	3,454,348.87
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	77,771,250.40	77,029,464.27
Plant Materials and Operating Supplies	39,863,187.70	37,926,559.97
Stores Expense	9,473,906.34	10,459,554.57
Emission Allowances	141,360.39	192,041.66
Prepayments	7,469,212.46	8,805,530.50
Miscellaneous Current and Accrued Assets	-	2,804,902.73
Total	630,136,287.51	366,841,668.05
Deferred Debits and Other		
Unamortized Debt Expense	20,978,499.55	18,816,119.96
Unamortized Loss on Bonds	9,079,509.10	9,450,932.73
Accumulated Deferred Income Taxes	291,712,726.72	189,224,915.51
Deferred Regulatory Assets	362,322,077.97	234,877,907.09
Other Deferred Debits	46,472,699.99	47,113,280.86
Total	730,565,513.33	499,483,156.15
Total Assets	$ 7,523,693,300.38	$ 6,613,128,962.88

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	538,858,083.00
Other Comprehensive Income	(2,135,445.12)	(1,225,421.72)
Retained Earnings	1,811,942,880.00	1,718,028,978.65
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,681,484,206.57	2,563,480,328.62
Other Long-Term Debt	2,590,974,880.28	2,090,592,379.36
Total Long-Term Debt	2,590,974,880.28	2,090,592,379.36
Total Capitalization	5,272,459,086.85	4,654,072,707.98
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	129,990,812.67
Accounts Payable	87,015,259.12	174,954,437.95
Accounts Payable to Associated Companies	40,966,804.31	29,400,562.53
Customer Deposits	26,165,653.70	26,738,302.05
Taxes Accrued	22,807,367.80	20,787,140.27
Interest Accrued	29,731,314.00	29,530,477.53
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	25,856,114.80	26,738,515.85
Total	232,542,513.73	438,140,248.85
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,309,650,199.83	975,682,757.53
Investment Tax Credit	93,480,489.57	95,332,955.57
Regulatory Liabilities	149,581,366.35	149,790,701.38
Customer Advances for Construction	2,038,832.16	2,465,621.82
Asset Retirement Obligations	358,268,971.83	208,595,134.24
Other Deferred Credits	12,158,554.90	40,389,078.66
Miscellaneous Long-Term Liabilities	2,349,494.89	1,672,390.37
Accum Provision for Pension & Postretirement Benefits	91,163,790.27	46,987,366.48
Total	2,018,691,699.80	1,520,916,006.05
Total Liabilities and Stockholders Equity	$ 7,523,693,300.38	$ 6,613,128,962.88

October 26, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of October 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,021,643,762.53	$ 8,555,402,692.50
Less: Reserves for Depreciation and Amortization	2,830,826,556.20	2,772,420,074.90
Total	6,190,817,206.33	5,782,982,617.60
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,720.15
Special Fund	-	-
Total	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash	4,919,659.13	3,957,771.15
Special Deposits	-	-
Temporary Cash Investments	297,177,806.71	8,951,092.09
Accounts Receivable-Less Reserve	202,165,792.26	190,519,269.94
Accounts Receivable from Associated Companies	(147,868.40)	23,154.07
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	91,304,834.59	87,809,179.21
Plant Materials and Operating Supplies	39,805,249.34	37,934,690.18
Stores Expense	9,458,382.00	10,151,022.64
Emission Allowances	141,198.17	182,719.63
Prepayments	6,421,417.80	7,495,599.51
Miscellaneous Current and Accrued Assets	-	2,359,144.20
Total	651,246,471.60	349,383,642.62
Deferred Debits and Other		
Unamortized Debt Expense	20,862,039.66	18,844,654.84
Unamortized Loss on Bonds	9,021,457.79	9,704,965.31
Accumulated Deferred Income Taxes	291,712,726.72	189,224,915.53
Deferred Regulatory Assets	368,382,149.02	244,052,150.26
Other Deferred Debits	47,124,509.04	47,265,516.62
Total	737,102,882.23	509,092,202.56
Total Assets	$ 7,580,387,873.26	$ 6,642,680,182.93

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	538,858,083.00
Other Comprehensive Income	(2,135,445.12)	(1,225,421.72)
Retained Earnings	1,823,841,396.42	1,729,998,960.60
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,693,382,722.99	2,575,450,310.57
Other Long-Term Debt	2,591,035,649.61	2,090,651,606.86
Total Long-Term Debt	2,591,035,649.61	2,090,651,606.86
Total Capitalization	5,284,418,372.60	4,666,101,917.43
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	129,990,476.90
Accounts Payable	119,548,552.69	169,385,746.07
Accounts Payable to Associated Companies	45,292,780.78	28,114,789.24
Customer Deposits	26,329,001.76	26,981,975.38
Taxes Accrued	20,221,087.23	26,584,074.43
Interest Accrued	37,209,732.96	35,530,696.65
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	21,040,809.46	33,055,446.01
Total	269,641,964.88	449,643,204.68
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,309,650,199.83	975,682,757.54
Investment Tax Credit	93,326,639.57	95,177,017.57
Regulatory Liabilities	152,863,716.77	153,787,656.01
Customer Advances for Construction	2,004,675.60	2,246,299.24
Asset Retirement Obligations	359,611,347.81	209,430,470.42
Other Deferred Credits	15,675,421.56	41,446,726.18
Miscellaneous Long-Term Liabilities	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits	91,145,542.96	46,979,825.71
Total	2,026,327,535.78	1,526,935,060.82
Total Liabilities and Stockholders Equity	$ 7,580,387,873.26	$ 6,642,680,182.93

November 20, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of November 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.......................................	$ 9,055,736,287.45	$ 8,598,961,464.32
Less: Reserves for Depreciation and Amortization......	2,848,167,882.46	2,784,835,792.14
Total...	6,207,568,404.99	5,814,125,672.18
Investments		
Electric Energy, Inc..	-	-
Ohio Valley Electric Company....................................	250,000.00	250,000.00
Nonutility Property-Less Reserve................................	971,313.10	971,720.15
Special Fund...	-	-
Total...	1,221,313.10	1,221,720.15
Current and Accrued Assets		
Cash..	5,962,204.01	10,156,826.59
Special Deposits...	-	-
Temporary Cash Investments......................................	6,017,862.15	12,300,587.98
Accounts Receivable-Less Reserve.............................	200,260,754.42	207,176,372.31
Accounts Receivable from Associated Companies......	25.07	23,154.07
Notes Receivable from Associated Companies...........	-	-
Materials and Supplies-At Average Cost		
Fuel...	98,247,174.52	93,515,847.19
Plant Materials and Operating Supplies....................	40,265,497.03	38,060,211.44
Stores Expense..	9,369,441.80	10,267,366.59
Emission Allowances..	140,908.58	169,828.50
Prepayments..	6,584,706.15	6,259,162.09
Miscellaneous Current and Accrued Assets................	-	311,056.62
Total...	366,848,573.73	378,240,413.38
Deferred Debits and Other		
Unamortized Debt Expense...	20,838,515.60	18,762,549.24
Unamortized Loss on Bonds.......................................	8,965,279.07	9,648,786.62
Accumulated Deferred Income Taxes.........................	291,712,726.72	189,224,915.53
Deferred Regulatory Assets...	373,592,653.42	258,030,499.78
Other Deferred Debits...	48,201,035.65	46,310,646.34
Total...	743,310,210.46	521,977,397.51
Total Assets...	$ 7,318,948,502.28	$ 6,715,565,203.22

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense...	321,288.87	321,288.87
Paid-In Capital..	563,858,083.00	538,858,083.00
Other Comprehensive Income..	(1,603,630.72)	(1,224,221.72)
Retained Earnings..	1,789,037,809.60	1,708,628,865.93
Unappropriated Undistributed Subsidiary Earnings............	-	-
Total Proprietary Capital..	2,659,110,950.57	2,554,081,415.90
Other Long-Term Debt...	2,341,084,854.05	1,840,708,923.79
Total Long-Term Debt..	2,341,084,854.05	1,840,708,923.79
Total Capitalization..	5,000,195,804.62	4,394,790,339.69
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.......................	-	-
Notes Payable...	-	446,844,639.42
Accounts Payable...	110,330,657.52	179,183,657.47
Accounts Payable to Associated Companies.......................	45,806,127.41	31,528,242.44
Customer Deposits...	26,152,692.53	27,047,613.43
Taxes Accrued..	30,326,633.07	26,441,711.12
Interest Accrued...	9,273,932.61	6,398,638.38
Dividends Declared..	47,000,000.00	36,000,000.00
Miscellaneous Current and Accrued Liabilities..................	22,480,161.70	44,257,165.66
Total...	291,370,204.84	797,701,667.92
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	1,309,650,199.83	975,682,290.74
Investment Tax Credit..	93,172,789.57	95,021,079.57
Regulatory Liabilities...	152,492,934.24	149,620,265.42
Customer Advances for Construction..................................	1,990,349.62	2,232,463.26
Asset Retirement Obligations...	359,654,554.66	210,171,982.88
Other Deferred Credits...	18,154,661.03	41,188,392.33
Miscellaneous Long-Term Liabilities..................................	2,049,991.68	2,184,308.15
Accum Provision for Pension & Postretirement Benefits.....	90,217,012.19	46,972,413.26
Total...	2,027,382,492.82	1,523,073,195.61
Total Liabilities and Stockholders Equity.................................	$ 7,318,948,502.28	$ 6,715,565,203.22

December 21, 2015

Kentucky Utilities Company
Comparative Balance Sheets as of December 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,082,008,901.23	$ 8,667,708,179.24
Less: Reserves for Depreciation and Amortization	2,849,851,989.11	2,798,968,737.30
Total	6,232,156,912.12	5,868,739,441.94
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	7,202,017.55	7,069,896.19
Special Deposits	-	-
Temporary Cash Investments	4,253,005.98	4,066,766.38
Accounts Receivable-Less Reserve	205,696,526.12	222,270,038.81
Accounts Receivable from Associated Companies	847,986.14	59,765,612.63
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	97,051,050.68	99,282,055.68
Plant Materials and Operating Supplies	41,183,222.05	38,655,516.05
Stores Expense	9,371,629.69	10,574,015.53
Emission Allowances	140,355.60	158,872.09
Prepayments	7,513,311.96	7,629,373.84
Miscellaneous Current and Accrued Assets	-	-
Total	373,259,105.77	449,472,147.20
Deferred Debits and Other		
Unamortized Debt Expense	20,924,669.19	18,614,826.72
Unamortized Loss on Bonds	8,907,227.76	9,590,735.30
Accumulated Deferred Income Taxes	358,038,655.59	221,690,913.50
Deferred Regulatory Assets	379,151,145.16	329,468,702.21
Other Deferred Debits	47,772,011.43	44,685,393.69
Total	814,793,709.13	624,050,571.42
Total Assets	$ 7,421,431,040.12	$ 6,943,483,473.66

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	563,858,083.00
Other Comprehensive Income	(1,627,215.32)	(1,232,509.32)
Retained Earnings	1,809,303,187.19	1,728,986,178.85
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,679,352,743.56	2,599,430,441.22
Other Long-Term Debt	2,341,130,601.99	2,090,768,151.28
Total Long-Term Debt	2,341,130,601.99	2,090,768,151.28
Total Capitalization	5,020,483,345.55	4,690,198,592.50
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	47,997,120.00	235,592,322.03
Accounts Payable	108,362,453.69	153,042,157.99
Accounts Payable to Associated Companies	39,179,663.47	46,590,075.29
Customer Deposits	26,249,503.24	27,255,893.31
Taxes Accrued	20,427,557.49	13,974,039.11
Interest Accrued	15,760,841.12	11,624,315.19
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	23,097,128.83	58,617,072.54
Total	281,074,267.84	546,695,875.46
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,404,626,225.28	1,104,287,220.74
Investment Tax Credit	93,018,937.57	94,865,139.57
Regulatory Liabilities	153,390,896.28	136,098,871.38
Customer Advances for Construction	1,968,685.25	2,218,445.28
Asset Retirement Obligations	362,143,424.48	210,966,863.53
Other Deferred Credits	8,679,929.34	38,495,003.59
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	93,702,288.92	117,607,469.93
Total	2,119,873,426.73	1,706,589,005.70
Total Liabilities and Stockholders Equity	$ 7,421,431,040.12	$ 6,943,483,473.66

January 27, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of January 31, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,098,475,991.88	$ 8,697,739,548.30
Less: Reserves for Depreciation and Amortization	2,871,164,186.50	2,815,155,222.08
Total	6,227,311,805.38	5,882,584,326.22
Investments		
Electric Energy, Inc	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	9,766,215.81	7,329,970.34
Special Deposits	-	-
Temporary Cash Investments	533,115.76	2,279,607.55
Accounts Receivable-Less Reserve	241,340,426.06	254,786,002.06
Accounts Receivable from Associated Companies	451.67	44,594,689.15
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	95,426,076.09	92,522,835.95
Plant Materials and Operating Supplies	41,582,541.41	38,415,753.80
Stores Expense	9,502,908.33	10,218,047.74
Emission Allowances	139,996.06	157,035.04
Prepayments	8,824,028.21	9,071,291.61
Miscellaneous Current and Accrued Assets	-	-
Total	407,115,759.40	459,375,233.24
Deferred Debits and Other		
Unamortized Debt Expense	21,347,224.95	18,428,635.08
Unamortized Loss on Bonds	8,849,304.04	9,532,683.94
Accumulated Deferred Income Taxes	358,038,655.58	221,690,913.49
Deferred Regulatory Assets	381,670,234.12	374,678,917.59
Other Deferred Debits	48,624,361.29	45,575,949.36
Total	818,529,779.98	669,907,099.46
Total Assets	$ 7,454,178,657.86	$ 7,013,087,972.02

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	563,858,083.00
Other Comprehensive Income	(1,627,215.32)	(1,232,509.32)
Retained Earnings	1,843,225,895.30	1,757,355,088.50
Total Proprietary Capital	2,713,275,451.67	2,627,799,350.87
Other Long-Term Debt	2,341,176,349.95	2,090,827,378.77
Total Long-Term Debt	2,341,176,349.95	2,090,827,378.77
Total Capitalization	5,054,451,801.62	4,718,626,729.64
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	43,220,464.71	290,967,792.63
Accounts Payable	97,387,109.16	113,754,496.22
Accounts Payable to Associated Companies	40,348,015.62	32,165,906.55
Customer Deposits	26,502,955.47	27,178,621.48
Taxes Accrued	37,004,690.00	9,204,464.82
Interest Accrued	23,012,165.99	17,618,885.17
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	20,361,542.06	106,699,730.46
Total	287,836,943.01	597,589,897.33
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,404,626,225.30	1,104,287,220.73
Investment Tax Credit	92,865,087.57	94,709,201.57
Regulatory Liabilities	149,814,487.60	138,973,112.29
Customer Advances for Construction	1,962,228.27	2,180,887.96
Asset Retirement Obligations	363,499,262.30	211,815,663.68
Other Deferred Credits	12,197,087.60	39,965,154.70
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	84,582,494.98	102,890,112.44
Total	2,111,889,913.23	1,696,871,345.05
Total Liabilities and Stockholders Equity	$ 7,454,178,657.86	$ 7,013,087,972.02

February 19, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of February 29, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,117,829,902.36	$ 8,724,392,698.03
Less: Reserves for Depreciation and Amortization	2,887,676,652.07	2,822,254,109.94
Total	6,230,153,250.29	5,902,138,588.09
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	11,076,890.09	6,340,684.46
Special Deposits	-	-
Temporary Cash Investments	870,208.15	8,033,998.95
Accounts Receivable-Less Reserve	248,609,673.37	269,107,973.17
Accounts Receivable from Associated Companies	25,565.99	33,685,035.94
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	100,903,235.63	85,358,312.27
Plant Materials and Operating Supplies	42,680,587.63	38,692,862.20
Stores Expense	9,760,323.81	10,328,880.13
Emission Allowances	139,529.50	155,398.87
Prepayments	7,733,167.69	9,259,755.88
Miscellaneous Current and Accrued Assets	-	-
Total	421,799,181.86	460,962,901.87
Deferred Debits and Other		
Unamortized Debt Expense	21,202,965.49	18,260,456.30
Unamortized Loss on Bonds	8,796,230.15	9,480,250.51
Accumulated Deferred Income Taxes	358,038,655.58	230,401,542.17
Deferred Regulatory Assets	378,391,004.93	345,565,960.90
Other Deferred Debits	49,103,736.01	43,873,804.19
Total	815,532,592.16	647,582,014.07
Total Assets	$ 7,468,706,337.41	$ 7,011,904,817.13

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	563,858,083.00
Other Comprehensive Income	(1,627,215.32)	(1,232,509.32)
Retained Earnings	1,804,943,557.88	1,756,861,620.75
Total Proprietary Capital	2,674,993,114.25	2,627,305,883.12
Other Long-Term Debt	2,341,219,146.42	2,090,880,874.57
Total Long-Term Debt	2,341,219,146.42	2,090,880,874.57
Total Capitalization	5,016,212,260.67	4,718,186,757.69
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	15,999,182.22	264,890,745.65
Accounts Payable	86,938,389.30	112,807,295.69
Accounts Payable to Associated Companies	39,150,288.77	35,212,922.28
Customer Deposits	27,098,711.83	27,274,071.04
Taxes Accrued	50,615,754.16	10,632,864.28
Interest Accrued	30,340,616.85	23,610,871.48
Dividends Declared	64,000,000.00	30,000,000.00
Miscellaneous Current and Accrued Liabilities	21,638,060.95	74,445,941.64
Total	335,781,004.08	578,874,712.06
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,404,626,225.30	1,119,204,755.90
Investment Tax Credit	92,711,237.57	94,553,263.57
Regulatory Liabilities	152,255,250.64	140,427,150.92
Customer Advances for Construction	1,906,222.58	2,160,348.44
Asset Retirement Obligations	364,860,646.01	212,661,999.12
Other Deferred Credits	13,447,658.41	40,913,399.62
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	84,562,792.54	102,872,438.13
Total	2,116,713,072.66	1,714,843,347.38
Total Liabilities and Stockholders Equity	$ 7,468,706,337.41	$ 7,011,904,817.13

March 21, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of March 31, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,146,829,155.36	$ 8,756,154,281.14
Less: Reserves for Depreciation and Amortization	2,908,490,568.18	2,823,695,881.95
Total	6,238,338,587.18	5,932,458,399.19
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	8,087,863.33	8,838,869.93
Special Deposits	-	-
Temporary Cash Investments	8,628,048.66	13,817,579.95
Accounts Receivable-Less Reserve	211,051,999.40	229,353,596.80
Accounts Receivable from Associated Companies	15,929.72	3,780.56
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	104,438,771.18	85,168,242.89
Plant Materials and Operating Supplies	42,735,185.41	38,255,517.55
Stores Expense	9,869,026.22	10,301,235.88
Emission Allowances	139,045.11	153,516.84
Prepayments	9,199,234.91	7,073,562.72
Miscellaneous Current and Accrued Assets	91.81	156.46
Total	394,165,195.75	392,966,059.58
Deferred Debits and Other		
Unamortized Debt Expense	21,057,206.39	18,074,299.24
Unamortized Loss on Bonds	8,739,495.94	9,422,199.19
Accumulated Deferred Income Taxes	347,806,640.29	233,812,122.48
Deferred Regulatory Assets	381,436,246.52	362,674,664.66
Other Deferred Debits	49,856,135.83	46,474,675.39
Total	808,895,724.97	670,457,960.96
Total Assets	$ 7,442,620,821.00	$ 6,997,103,732.83

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	563,858,083.00
Other Comprehensive Income	(1,770,922.52)	(2,137,644.72)
Retained Earnings	1,820,248,627.04	1,777,247,894.75
Total Proprietary Capital	2,690,154,476.21	2,646,787,021.72
Other Long-Term Debt	2,341,264,894.37	2,090,940,102.07
Total Long-Term Debt	2,341,264,894.37	2,090,940,102.07
Total Capitalization	5,031,419,370.58	4,737,727,123.79
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	33,997,593.89	192,947,747.17
Accounts Payable	83,354,275.13	120,407,085.40
Accounts Payable to Associated Companies	42,286,429.79	33,345,532.72
Customer Deposits	27,331,950.94	27,238,382.69
Taxes Accrued	12,040,879.37	13,323,031.00
Interest Accrued	37,623,974.08	29,640,399.19
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	22,371,070.37	87,544,924.73
Total	259,006,173.57	504,447,102.90
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,438,942,577.25	1,160,095,669.43
Investment Tax Credit	92,557,387.57	94,403,589.57
Regulatory Liabilities	156,046,050.47	140,750,798.01
Customer Advances for Construction	1,895,955.59	2,148,289.69
Asset Retirement Obligations	366,227,599.06	213,517,919.65
Other Deferred Credits	10,236,246.85	39,752,928.60
Miscellaneous Long-Term Liabilities	2,264,617.75	2,189,595.08
Accum Provision for Pension & Postretirement Benefits	84,024,842.31	102,070,716.11
Total	2,152,195,276.85	1,754,929,506.14
Total Liabilities and Stockholders Equity	$ 7,442,620,821.00	$ 6,997,103,732.83

April 26, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of April 30, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,170,289,102.99	$ 8,785,148,966.75
Less: Reserves for Depreciation and Amortization	2,925,527,193.09	2,829,095,375.74
Total	6,244,761,909.90	5,956,053,591.01
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	5,137,250.87	4,108,539.62
Special Deposits	-	-
Temporary Cash Investments	10,871,108.30	3,348,985.91
Accounts Receivable-Less Reserve	197,056,735.45	198,343,445.09
Accounts Receivable from Associated Companies	2,788,846.05	176,601.56
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	105,432,525.42	91,058,972.11
Plant Materials and Operating Supplies	43,254,596.74	38,623,349.94
Stores Expense	9,943,821.01	10,218,182.51
Emission Allowances	138,631.59	151,533.42
Prepayments	12,853,714.97	10,488,582.86
Miscellaneous Current and Accrued Assets	-	-
Total	387,477,230.40	356,518,193.02
Deferred Debits and Other		
Unamortized Debt Expense	20,896,787.15	17,894,295.98
Unamortized Loss on Bonds	8,684,591.92	9,366,020.49
Accumulated Deferred Income Taxes	347,806,640.29	233,812,122.48
Deferred Regulatory Assets	388,274,642.47	356,890,250.18
Other Deferred Debits	48,944,700.99	47,257,428.47
Total	814,607,362.82	665,220,117.60
Total Assets	$ 7,448,067,816.22	$ 6,979,013,214.73

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	563,858,083.00
Other Comprehensive Income	(1,770,922.52)	(2,137,644.72)
Retained Earnings	1,832,232,903.46	1,781,989,519.33
Total Proprietary Capital	2,702,138,752.63	2,651,528,646.30
Other Long-Term Debt	2,341,309,166.56	2,090,997,418.99
Total Long-Term Debt	2,341,309,166.56	2,090,997,418.99
Total Capitalization	5,043,447,919.19	4,742,526,065.29
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	21,341,253.03	150,011,667.76
Accounts Payable	87,905,720.00	125,124,623.69
Accounts Payable to Associated Companies	44,461,776.95	40,537,871.10
Customer Deposits	27,528,309.63	27,159,704.31
Taxes Accrued	14,285,198.44	26,751,143.21
Interest Accrued	35,171,367.16	35,638,144.07
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	19,092,388.69	74,770,417.33
Total	249,786,013.90	479,993,571.47
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,438,942,577.25	1,160,095,669.43
Investment Tax Credit	92,403,537.57	94,249,739.57
Regulatory Liabilities	155,859,961.15	140,159,458.64
Customer Advances for Construction	1,871,404.68	2,134,453.70
Asset Retirement Obligations	367,600,145.23	214,374,279.94
Other Deferred Credits	11,808,616.85	41,204,207.16
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	84,004,600.79	102,225,777.85
Total	2,154,833,883.13	1,756,493,577.97
Total Liabilities and Stockholders Equity	$ 7,448,067,816.22	$ 6,979,013,214.73

May 20, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of May 31, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,188,182,485.81	$ 8,802,310,025.86
Less: Reserves for Depreciation and Amortization	2,938,123,448.80	2,826,457,728.53
Total	6,250,059,037.01	5,975,852,297.33
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	7,349,119.82	8,206,612.86
Special Deposits	-	-
Temporary Cash Investments	43,043.33	531,207.78
Accounts Receivable-Less Reserve	195,762,976.19	200,113,862.31
Accounts Receivable from Associated Companies	8,434,482.36	-
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	109,630,244.84	95,073,396.34
Plant Materials and Operating Supplies	43,339,609.60	38,989,822.24
Stores Expense	10,107,824.54	10,048,613.24
Emission Allowances	138,142.50	149,894.71
Prepayments	11,235,249.74	9,575,108.78
Miscellaneous Current and Accrued Assets	-	-
Total	386,040,692.92	362,688,518.26
Deferred Debits and Other		
Unamortized Debt Expense	20,729,979.05	17,708,295.26
Unamortized Loss on Bonds	8,627,857.68	9,307,969.15
Accumulated Deferred Income Taxes	353,795,499.04	233,812,122.48
Deferred Regulatory Assets	392,969,537.92	351,325,173.81
Other Deferred Debits	49,574,541.16	47,619,002.58
Total	825,697,414.85	659,772,563.28
Total Assets	$ 7,463,018,457.88	$ 6,999,534,691.97

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	563,858,083.00	563,858,083.00
Other Comprehensive Income	(1,777,276.92)	(2,137,844.72)
Retained Earnings	1,800,437,637.70	1,745,905,990.86
Total Proprietary Capital	2,670,337,132.47	2,615,444,917.83
Other Long-Term Debt	2,341,354,914.52	2,091,056,646.48
Total Long-Term Debt	2,341,354,914.52	2,091,056,646.48
Total Capitalization	5,011,692,046.99	4,706,501,564.31
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	33,998,612.87	192,912,103.55
Accounts Payable	74,810,180.11	117,464,116.94
Accounts Payable to Associated Companies	41,024,277.04	33,482,611.06
Customer Deposits	27,572,209.74	26,924,126.01
Taxes Accrued	14,356,770.34	38,312,996.05
Interest Accrued	9,249,233.24	6,456,040.61
Dividends Declared	49,000,000.00	51,000,000.00
Miscellaneous Current and Accrued Liabilities	20,700,404.75	68,197,447.56
Total	270,711,688.09	534,749,441.78
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,463,651,548.89	1,160,095,747.23
Investment Tax Credit	92,249,687.57	94,095,889.57
Regulatory Liabilities	154,442,586.37	140,511,751.93
Customer Advances for Construction	1,819,393.10	2,089,757.74
Asset Retirement Obligations	368,978,308.33	215,236,992.95
Other Deferred Credits	13,146,019.44	42,918,930.64
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	83,984,139.49	101,284,624.14
Total	2,180,614,722.80	1,758,283,685.88
Total Liabilities and Stockholders Equity	$ 7,463,018,457.88	$ 6,999,534,691.97

June 21, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of June 30, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.......................................	$ 9,208,300,167.82	$ 8,946,519,669.45
Less: Reserves for Depreciation and Amortization.......	2,950,992,350.83	2,838,963,550.95
Total...	6,257,307,816.99	6,107,556,118.50
Investments		
Electric Energy, Inc..	-	-
Ohio Valley Electric Company....................................	250,000.00	250,000.00
Nonutility Property-Less Reserve................................	971,313.10	971,313.10
Special Fund...	-	-
Total...	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash..	5,518,998.81	5,007,417.03
Special Deposits..	-	-
Temporary Cash Investments.......................................	2,171,256.90	1,029,502.66
Accounts Receivable-Less Reserve..............................	210,816,417.62	217,142,773.94
Accounts Receivable from Associated Companies........	1,862.99	2,475.15
Notes Receivable from Associated Companies............	-	-
Materials and Supplies-At Average Cost		
Fuel..	103,727,160.85	96,160,683.02
Plant Materials and Operating Supplies.....................	43,016,000.18	40,306,886.36
Stores Expense..	10,208,177.00	10,102,105.59
Emission Allowances...	137,630.42	148,114.70
Prepayments..	19,623,348.16	11,365,369.57
Miscellaneous Current and Accrued Assets...................	-	132,969.39
Total...	395,220,852.93	381,398,297.41
Deferred Debits and Other		
Unamortized Debt Expense...	20,568,570.58	17,528,295.46
Unamortized Loss on Bonds..	8,572,953.64	9,251,790.44
Accumulated Deferred Income Taxes..........................	360,087,024.48	274,105,539.40
Deferred Regulatory Assets...	399,163,574.25	323,925,739.71
Other Deferred Debits...	50,321,330.89	47,686,435.41
Total...	838,713,453.84	672,497,800.42
Total Assets...	$ 7,492,463,436.86	$ 7,162,673,529.43

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense...	321,288.87	321,288.87
Paid-In Capital..	583,858,083.00	563,858,083.00
Other Comprehensive Income...	(1,785,097.72)	(2,136,544.92)
Retained Earnings..	1,826,037,398.82	1,765,169,748.05
Total Proprietary Capital...	2,715,929,072.79	2,634,709,974.82
Other Long-Term Debt..	2,341,399,186.73	2,091,113,963.42
Total Long-Term Debt...	2,341,399,186.73	2,091,113,963.42
Total Capitalization...	5,057,328,259.52	4,725,823,938.24
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.........................	-	-
Notes Payable..	28,997,472.22	226,951,047.46
Accounts Payable...	81,268,204.87	132,208,798.33
Accounts Payable to Associated Companies.........................	52,696,233.21	35,866,268.59
Customer Deposits...	27,610,573.63	26,798,081.70
Taxes Accrued...	16,684,855.57	28,167,428.29
Interest Accrued..	15,627,585.43	11,749,580.88
Dividends Declared...	-	-
Miscellaneous Current and Accrued Liabilities....................	23,230,925.25	50,358,707.86
Total..	246,115,850.18	512,099,913.11
Deferred Credits and Other		
Accumulated Deferred Income Taxes..................................	1,479,982,520.76	1,242,172,308.58
Investment Tax Credit..	96,095,837.57	93,942,039.57
Regulatory Liabilities...	155,371,908.99	147,086,307.88
Customer Advances for Construction...................................	1,575,372.10	2,087,427.22
Asset Retirement Obligations...	370,362,112.21	333,687,598.72
Other Deferred Credits..	3,536,916.21	11,329,447.82
Miscellaneous Long-Term Liabilities...................................	2,147,543.43	2,316,685.53
Accum Provision for Pension & Postretirement Benefits......	79,947,115.89	92,127,862.76
Total..	2,189,019,327.16	1,924,749,678.08
Total Liabilities and Stockholders Equity.................................	$ 7,492,463,436.86	$ 7,162,673,529.43

July 27, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of July 31, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,223,319,830.50	$ 8,969,491,437.29
Less: Reserves for Depreciation and Amortization	2,964,992,413.00	2,854,118,353.29
Total	6,258,327,417.50	6,115,373,084.00
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	10,498,783.84	4,419,789.97
Special Deposits	-	-
Temporary Cash Investments	249,357.20	396,770.05
Accounts Receivable-Less Reserve	244,576,349.06	231,347,683.52
Accounts Receivable from Associated Companies	2,818.53	548.73
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	100,078,000.66	91,394,266.05
Plant Materials and Operating Supplies	43,570,979.67	40,241,376.39
Stores Expense	10,306,666.36	10,082,872.94
Emission Allowances	137,132.42	144,281.66
Prepayments	21,128,715.76	9,889,894.18
Miscellaneous Current and Accrued Assets	-	-
Total	430,548,803.50	387,917,483.49
Deferred Debits and Other		
Unamortized Debt Expense	20,401,748.03	17,236,365.70
Unamortized Loss on Bonds	8,516,219.44	9,193,739.16
Accumulated Deferred Income Taxes	360,087,024.48	274,105,539.40
Deferred Regulatory Assets	402,792,757.70	346,482,823.82
Other Deferred Debits	51,312,911.52	47,958,912.08
Total	843,110,661.17	694,977,380.16
Total Assets	$ 7,533,208,195.27	$ 7,199,489,260.75

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	583,858,083.00	563,858,083.00
Other Comprehensive Income	(1,785,097.72)	(2,136,544.92)
Retained Earnings	1,853,723,000.84	1,790,746,737.55
Unappropriated Undistributed Subsidiary Earnings	-	-
Total Proprietary Capital	2,743,614,674.81	2,660,286,964.32
Other Long-Term Debt	2,341,444,934.68	2,091,173,190.91
Total Long-Term Debt	2,341,444,934.68	2,091,173,190.91
Total Capitalization	5,085,059,609.49	4,751,460,155.23
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	21,999,586.67	210,884,216.98
Accounts Payable	84,751,623.21	118,546,994.57
Accounts Payable to Associated Companies	40,543,387.71	28,777,148.32
Customer Deposits	27,771,029.84	26,491,600.15
Taxes Accrued	36,603,994.94	46,434,239.58
Interest Accrued	22,872,743.17	17,745,890.81
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	21,030,192.85	69,589,721.47
Total	255,572,558.39	518,469,811.88
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,479,982,520.76	1,242,172,308.58
Investment Tax Credit	95,941,987.57	93,788,189.57
Regulatory Liabilities	154,199,878.41	149,499,338.66
Customer Advances for Construction	1,599,134.50	2,051,489.08
Asset Retirement Obligations	373,532,574.06	335,063,348.55
Other Deferred Credits	5,050,369.34	12,824,781.34
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	79,926,523.14	92,109,846.18
Total	2,192,576,027.39	1,929,559,293.64
Total Liabilities and Stockholders Equity	$ 7,533,208,195.27	$ 7,199,489,260.75

August 19, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of August 31, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,235,422,348.11	$ 8,984,536,417.11
Less: Reserves for Depreciation and Amortization	2,980,088,654.41	2,854,322,446.77
Total	6,255,333,693.70	6,130,213,970.34
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	8,711,701.09	8,875,349.87
Special Deposits	-	-
Temporary Cash Investments	942,198.83	1,288,014.74
Accounts Receivable-Less Reserve	244,904,320.32	230,535,436.96
Accounts Receivable from Associated Companies	208,640.74	-
Notes Receivable from Associated Companies	33,000,000.00	-
Materials and Supplies-At Average Cost		
Fuel	97,618,732.38	87,828,326.60
Plant Materials and Operating Supplies	44,476,438.62	40,529,934.08
Stores Expense	10,515,070.84	9,994,443.59
Emission Allowances	136,559.78	142,665.14
Prepayments	21,195,410.16	8,597,350.84
Miscellaneous Current and Accrued Assets	-	-
Total	461,709,072.76	387,791,521.82
Deferred Debits and Other		
Unamortized Debt Expense	19,770,745.89	17,052,758.57
Unamortized Loss on Bonds	9,648,232.90	9,135,687.78
Accumulated Deferred Income Taxes	351,912,940.78	274,729,581.86
Deferred Regulatory Assets	406,740,879.04	350,292,726.00
Other Deferred Debits	50,434,294.08	48,418,643.60
Total	838,507,092.69	699,629,397.81
Total Assets	$ 7,556,771,172.25	$ 7,218,856,203.07

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	583,858,083.00	563,858,083.00
Other Comprehensive Income	(1,795,297.72)	(2,136,744.92)
Retained Earnings	1,798,594,116.42	1,791,547,052.66
Total Proprietary Capital	2,688,475,590.39	2,661,087,079.43
Other Long-Term Debt	2,341,490,682.64	2,091,232,418.40
Total Long-Term Debt	2,341,490,682.64	2,091,232,418.40
Total Capitalization	5,029,966,273.03	4,752,319,497.83
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	213,987,852.02
Accounts Payable	78,345,166.55	93,354,282.55
Accounts Payable to Associated Companies	43,216,664.22	24,538,008.58
Customer Deposits	28,000,984.02	26,302,851.05
Taxes Accrued	59,382,341.43	65,177,108.17
Interest Accrued	30,139,072.19	23,535,588.70
Dividends Declared	84,000,000.00	25,000,000.00
Miscellaneous Current and Accrued Liabilities	21,651,638.87	64,623,488.05
Total	344,735,867.28	536,519,179.12
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,469,832,526.73	1,242,420,535.88
Investment Tax Credit	95,788,137.57	93,634,339.57
Regulatory Liabilities	157,330,338.78	148,691,847.54
Customer Advances for Construction	1,576,406.04	2,050,145.10
Asset Retirement Obligations	369,962,422.88	336,372,286.18
Other Deferred Credits	6,310,541.56	13,616,132.38
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	78,925,618.77	91,182,247.79
Total	2,182,069,031.94	1,930,017,526.12
Total Liabilities and Stockholders Equity	$ 7,556,771,172.25	$ 7,218,856,203.07

September 22, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of September 30, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,167,737,882.97	$ 8,976,329,597.43
Less: Reserves for Depreciation and Amortization	2,998,643,955.20	2,814,559,410.99
Total	6,169,093,927.77	6,161,770,186.44
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	6,552,923.36	5,693,686.69
Special Deposits	-	-
Temporary Cash Investments	539,076.76	269,198,327.26
Accounts Receivable-Less Reserve	228,217,319.18	220,519,068.47
Accounts Receivable from Associated Companies	620,839.43	6,287.80
Notes Receivable from Associated Companies	-	-
Materials and Supplies-At Average Cost		
Fuel	95,732,452.30	77,771,250.40
Plant Materials and Operating Supplies	45,096,560.21	39,863,187.70
Stores Expense	10,558,689.69	9,473,906.34
Emission Allowances	136,198.37	141,360.39
Prepayments	19,633,610.73	7,469,212.46
Miscellaneous Current and Accrued Assets	-	-
Total	407,087,670.03	630,136,287.51
Deferred Debits and Other		
Unamortized Debt Expense	19,608,012.47	20,978,499.55
Unamortized Loss on Bonds	9,595,404.13	9,079,509.10
Accumulated Deferred Income Taxes	299,127,133.79	291,712,726.72
Deferred Regulatory Assets	407,450,667.53	362,322,077.97
Other Deferred Debits	51,507,738.65	46,472,699.99
Total	787,288,956.57	730,565,513.33
Total Assets	$ 7,364,691,867.47	$ 7,523,693,300.38

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	583,858,083.00	563,858,083.00
Other Comprehensive Income	(1,799,150.72)	(2,135,445.12)
Retained Earnings	1,820,031,844.39	1,811,942,880.00
Total Proprietary Capital	2,709,909,465.36	2,681,484,206.57
Other Long-Term Debt	2,341,534,954.84	2,590,974,880.34
Total Long-Term Debt	2,341,534,954.84	2,590,974,880.34
Total Capitalization	5,051,444,420.20	5,272,459,086.91
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable to Associated Companies	-	-
Notes Payable	6,999,556.67	(0.06)
Accounts Payable	77,287,180.83	87,015,259.12
Accounts Payable to Associated Companies	41,596,348.87	40,966,804.31
Customer Deposits	28,315,862.36	26,165,653.70
Taxes Accrued	23,466,579.74	22,807,367.80
Interest Accrued	37,528,033.68	29,731,314.00
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	22,883,302.00	25,856,114.80
Total	238,076,864.15	232,542,513.67
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,464,910,392.66	1,309,650,199.83
Investment Tax Credit	95,634,287.57	93,480,489.57
Regulatory Liabilities	156,579,563.01	149,581,366.35
Customer Advances for Construction	1,567,242.53	2,038,832.16
Asset Retirement Obligations	276,684,290.53	358,268,971.83
Other Deferred Credits	4,049,243.91	12,158,554.90
Miscellaneous Long-Term Liabilities	2,040,580.67	2,349,494.89
Accum Provision for Pension & Postretirement Benefits	73,704,982.24	91,163,790.27
Total	2,075,170,583.12	2,018,691,699.80
Total Liabilities and Stockholders Equity	$ 7,364,691,867.47	$ 7,523,693,300.38

October 26, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of October 31, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,191,500,911.78	$ 9,021,643,762.53
Less: Reserves for Depreciation and Amortization	3,014,975,282.47	2,830,826,556.20
Total	6,176,525,629.31	6,190,817,206.33
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	10,174,587.34	4,919,659.13
Special Deposits	-	-
Temporary Cash Investments	107,931.00	297,177,806.71
Accounts Receivable-Less Reserve	198,939,357.85	202,165,792.26
Accounts Receivable from Associated Companies	-	(147,868.40)
Notes Receivable from Associated Companies	37,600,000.00	-
Materials and Supplies-At Average Cost		
Fuel	89,746,094.82	91,304,834.59
Plant Materials and Operating Supplies	44,367,777.37	39,805,249.34
Stores Expense	10,683,263.70	9,458,382.00
Emission Allowances	135,994.66	141,198.17
Prepayments	17,650,507.13	6,421,417.80
Miscellaneous Current and Accrued Assets	-	-
Total	409,405,513.87	651,246,471.60
Deferred Debits and Other		
Unamortized Debt Expense	19,553,798.24	20,862,039.66
Unamortized Loss on Bonds	9,542,889.19	9,021,457.79
Accumulated Deferred Income Taxes	299,127,133.79	291,712,726.72
Deferred Regulatory Assets	409,284,568.61	368,382,149.02
Other Deferred Debits	52,653,397.23	47,124,509.04
Total	790,161,787.06	737,102,882.23
Total Assets	$ 7,377,314,243.34	$ 7,580,387,873.26

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	583,858,083.00	563,858,083.00
Other Comprehensive Income	(1,799,150.72)	(2,135,445.12)
Retained Earnings	1,834,414,979.39	1,823,841,396.42
Total Proprietary Capital	2,724,292,600.36	2,693,382,722.99
Other Long-Term Debt	2,341,580,702.80	2,591,035,649.61
Total Long-Term Debt	2,341,580,702.80	2,591,035,649.61
Total Capitalization	5,065,873,303.16	5,284,418,372.60
Current and Accrued Liabilities		
Accounts Payable	92,845,620.94	119,548,552.69
Accounts Payable to Associated Companies	41,199,689.05	45,292,780.78
Customer Deposits	28,417,765.40	26,329,001.76
Taxes Accrued	21,972,593.94	20,221,087.23
Interest Accrued	35,285,275.28	37,209,732.96
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	18,523,136.28	21,040,809.46
Total	238,244,080.89	269,641,964.88
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,464,910,392.66	1,309,650,199.83
Investment Tax Credit	95,480,437.57	93,326,639.57
Regulatory Liabilities	153,680,928.09	152,863,716.77
Customer Advances for Construction	1,545,101.26	2,004,675.60
Asset Retirement Obligations	275,768,831.27	359,611,347.81
Other Deferred Credits	5,783,762.06	15,675,421.56
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	73,684,366.77	91,145,542.96
Total	2,073,196,859.29	2,026,327,535.78
Total Liabilities and Stockholders Equity	$ 7,377,314,243.34	$ 7,580,387,873.26

November 21, 2016

Kentucky Utilities Company
Comparative Balance Sheets as of November 30, 2016 and 2015

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 9,229,114,514.13	$ 9,055,736,287.45
Less: Reserves for Depreciation and Amortization	3,033,321,164.75	2,848,167,882.46
Total	6,195,793,349.38	6,207,568,404.99
Investments		
Electric Energy, Inc.	-	-
Ohio Valley Electric Company	250,000.00	250,000.00
Nonutility Property-Less Reserve	971,313.10	971,313.10
Special Fund	-	-
Total	1,221,313.10	1,221,313.10
Current and Accrued Assets		
Cash	7,256,777.37	5,962,204.01
Special Deposits	-	-
Temporary Cash Investments	16,270,595.66	6,017,862.15
Accounts Receivable-Less Reserve	200,581,880.85	200,260,754.42
Accounts Receivable from Associated Companies	3,102.85	25.07
Notes Receivable from Associated Companies	3,800,000.00	-
Materials and Supplies-At Average Cost		
Fuel	93,845,858.51	98,247,174.52
Plant Materials and Operating Supplies	44,431,778.29	40,265,497.03
Stores Expense	10,684,074.11	9,369,441.80
Emission Allowances	135,553.45	140,908.58
Prepayments	16,064,036.91	6,584,706.15
Miscellaneous Current and Accrued Assets	-	-
Total	393,073,658.00	366,848,573.73
Deferred Debits and Other		
Unamortized Debt Expense	19,383,855.88	20,838,515.60
Unamortized Loss on Bonds	9,490,060.38	8,965,279.07
Accumulated Deferred Income Taxes	299,127,133.79	291,712,726.72
Deferred Regulatory Assets	413,790,471.39	373,592,653.42
Other Deferred Debits	53,418,807.29	48,201,035.65
Total	795,210,328.73	743,310,210.46
Total Assets	$ 7,385,298,649.21	$ 7,318,948,502.28

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 308,139,977.56	$ 308,139,977.56
Less: Common Stock Expense	321,288.87	321,288.87
Paid-In Capital	583,858,083.00	563,858,083.00
Other Comprehensive Income	(1,809,350.72)	(1,603,630.72)
Retained Earnings	1,798,829,870.41	1,789,037,809.60
Total Proprietary Capital	2,688,697,291.38	2,659,110,950.57
Other Long-Term Debt	2,341,624,974.99	2,341,084,854.05
Total Long-Term Debt	2,341,624,974.99	2,341,084,854.05
Total Capitalization	5,030,322,266.37	5,000,195,804.62
Current and Accrued Liabilities		
Accounts Payable	90,902,790.94	110,330,657.52
Accounts Payable to Associated Companies	35,483,964.50	45,806,127.41
Customer Deposits	28,643,972.31	26,152,692.53
Taxes Accrued	34,093,454.97	30,326,633.07
Interest Accrued	9,456,757.18	9,273,932.61
Dividends Declared	51,000,000.00	47,000,000.00
Miscellaneous Current and Accrued Liabilities	20,244,873.35	22,480,161.70
Total	269,825,813.25	291,370,204.84
Deferred Credits and Other		
Accumulated Deferred Income Taxes	1,464,914,360.46	1,309,650,199.83
Investment Tax Credit	95,326,587.57	93,172,789.57
Regulatory Liabilities	152,776,864.79	152,492,934.24
Customer Advances for Construction	1,534,950.38	1,990,349.62
Asset Retirement Obligations	288,537,422.93	359,654,554.66
Other Deferred Credits	6,053,384.30	18,154,661.03
Miscellaneous Long-Term Liabilities	2,343,039.61	2,049,991.68
Accum Provision for Pension & Postretirement Benefits	73,663,959.55	90,217,012.19
Total	2,085,150,569.59	2,027,382,492.82
Total Liabilities and Stockholders Equity	$ 7,385,298,649.21	$ 7,318,948,502.28

December 21, 2016

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As of Jul 2014
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 08-07-14 Run Time: 11:30:11 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	119 Kentucky Utilities Company Purchase Acctg	Eliminations	10_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	8,870,182.24	0.00	0.00	8,870,182.24	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	139,393,123.61	0.00	0.00	139,393,123.61	0.00
OtherAR Other	22,058,761.17	0.00	0.00	22,058,761.17	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	36,991.62	0.00	0.00	36,991.62	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	77,747,710.98	0.00	0.00	77,747,710.98	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	124,477,142.54	0.00	0.00	124,477,142.54	0.00
Prepayments	9,605,598.16	0.00	0.00	9,605,598.16	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	987,923.56	0.00	0.00	987,923.56	0.00
RegulatoryCurrentAssets Regulatory assets	2,536,056.26	0.00	0.00	2,536,056.26	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,007,221.47	234,242.40	0.00	3,241,463.87	0.00
Total current assets	388,720,711.61	234,242.40	0.00	388,954,954.01	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,270,371,916.74	(1,785,127,532.66)	0.00	5,485,244,384.08	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant a	971,720.15	0.00	0.00	971,720.15	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regu	(2,325,124,900.96)	1,785,127,532.79	(0.00)	(539,997,368.17)	(0.00)
ConstructionWorkInProgress Construction work in progress	1,085,024,077.76	(0.13)	0.00	1,085,024,077.63	0.00
Property, plant and equipment, net	6,031,242,813.69	0.00	0.00	6,031,242,813.69	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	161,717,348.08	4,163,637.73	0.00	165,880,985.81	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,567,796.53	73,400,372.24	0.00	86,968,168.77	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
PriceRiskManagementAssetsLongTerm Price risk management asse	867,901.15	0.00	0.00	867,901.15	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	63,046,796.64	(3,647,248.64)	0.00	59,399,548.00	0.00
Total other noncurrent assets	239,199,842.40	681,321,129.56	0.00	920,520,971.96	0.00
Total Assets	6,659,163,367.70	681,555,371.96	0.00	7,340,718,739.66	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	159,990,476.78	0.00	0.00	159,990,476.78	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	142,157,604.82	0.00	0.00	142,157,604.82	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	30,029,038.19	0.00	0.00	30,029,038.19	0.00
TaxesAccrued Taxes	18,256,419.62	0.00	0.00	18,256,419.62	0.00
InterestAccrued Interest	17,432,611.64	0.00	0.00	17,432,611.64	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	2,114,000.00	234,242.40	0.00	2,348,242.40	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,565,323.59	0.00	0.00	26,565,323.59	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilitie	32,688,734.54	0.00	0.00	32,688,734.54	0.00
Total current liabilities	429,234,209.18	234,242.40	0.00	429,468,451.58	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,090,475,834.94	587,021.73	0.00	2,091,062,856.67	0.00
NotesPayableToAffiliates Notes payable to affiliate	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,090,475,834.94	587,021.73	0.00	2,091,062,856.67	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	746,999,426.45	(221,666.35)	0.00	746,777,760.10	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,644,833.57	0.00	0.00	95,644,833.57	0.00
PriceRiskManagementLiabilitiesLongTerm Price risk management lia	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	1,894,794.64	0.00	0.00	1,894,794.64	0.00
AssetRetirementObligations Asset retirement obligations	186,209,271.79	0.00	0.00	186,209,271.79	0.00
RegulatoryLiabilities Regulatory liabilities	467,811,780.28	73,400,372.24	0.00	541,212,152.52	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liab	88,494,879.90	516,389.09	0.00	89,011,268.99	0.00
	1,587,054,986.63	73,695,094.98	0.00	1,660,750,081.61	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	538,858,083.00	2,032,588,750.94	0.00	2,571,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,706,987,458.38	(1,427,061,370.85)	0.00	279,926,087.53	0.00
AccumulatedOtherComprehensiveIncome Accumulated other compr	(1,265,893.12)	1,511,632.76	0.00	245,739.64	0.00
Total equity	2,552,398,336.95	607,039,012.85	0.00	3,159,437,349.80	0.00
Total liabilities and equity	**6,659,163,367.70**	**681,555,371.96**	**0.00**	**7,340,718,739.66**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**6,659,163,367.70**	**681,555,371.96**	**0.00**	**7,340,718,739.66**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**6,659,163,367.70**	**681,555,371.96**	**0.00**	**7,340,718,739.66**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofAug 2014
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 09-08-14 Run Time: 12:26:14 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	26,670,056.97	0.00	0.00	26,670,056.97	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	121,475,442.67	0.00	0.00	121,475,442.67	0.00
OtherAR Other	8,314,560.75	0.00	0.00	8,314,560.75	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	38,458.83	0.00	0.00	38,458.83	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	91,102,198.63	0.00	0.00	91,102,198.63	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	124,349,805.29	0.00	0.00	124,349,805.29	0.00
Prepayments	8,564,228.10	0.00	0.00	8,564,228.10	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	721,665.50	0.00	0.00	721,665.50	0.00
RegulatoryCurrentAssets Regulatory assets	1,715,429.60	0.00	0.00	1,715,429.60	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,274,281.36	232,077.30	0.00	3,506,358.66	0.00
Total current assets	386,226,127.70	232,077.30	0.00	386,458,205.00	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,313,424,877.24	(1,782,249,355.46)	0.00	5,531,175,521.78	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant and	971,720.15	0.00	0.00	971,720.15	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,333,237,989.89)	1,782,249,355.59	(0.00)	(550,988,634.30)	(0.00)
ConstructionWorkInProgress Construction work in progress	1,095,969,089.66	(0.13)	0.00	1,095,969,089.53	0.00
Property, plant and equipment, net	6,077,127,697.16	0.00	0.00	6,077,127,697.16	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	168,223,788.82	4,087,656.16	0.00	172,311,444.98	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,541,962.28	71,412,209.80	0.00	84,954,172.08	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	23,617.75	0.00	0.00	23,617.75	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	62,786,072.94	(3,630,206.49)	0.00	59,155,866.45	0.00
Total other noncurrent assets	244,575,441.79	679,274,027.70	0.00	923,849,469.49	0.00
Total Assets	6,707,929,266.65	679,506,105.00	0.00	7,387,435,371.65	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	129,990,799.69	0.00	0.00	129,990,799.69	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	151,283,998.54	0.00	0.00	151,283,998.54	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	30,349,865.34	0.00	0.00	30,349,865.34	0.00
TaxesAccrued Taxes	42,602,040.93	0.00	0.00	42,602,040.93	0.00
InterestAccrued Interest	23,425,812.47	0.00	0.00	23,425,812.47	0.00
DividendsPayable Dividends	26,000,000.00	0.00	0.00	26,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	1,263,447.71	232,077.30	0.00	1,495,525.01	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,702,517.05	0.00	0.00	26,702,517.05	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	29,307,689.94	0.00	0.00	29,307,689.94	0.00
Total current liabilities	460,926,171.67	232,077.30	0.00	461,158,248.97	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,090,535,062.43	574,004.98	0.00	2,091,109,067.41	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,090,535,062.43	574,004.98	0.00	2,091,109,067.41	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	747,846,912.12	(209,917.82)	0.00	747,636,994.30	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,488,895.57	0.00	0.00	95,488,895.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	5,686,772.30	0.00	0.00	5,686,772.30	0.00
AccruedPensionObligations Accrued pension obligations	1,924,465.39	0.00	0.00	1,924,465.39	0.00
AssetRetirementObligations Asset retirement obligations	206,344,110.46	0.00	0.00	206,344,110.46	0.00
RegulatoryLiabilities Regulatory liabilities	460,959,450.25	71,412,209.80	0.00	532,371,660.05	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	88,827,483.47	457,449.67	0.00	89,284,933.14	0.00
	1,607,078,089.56	71,659,741.65	0.00	1,678,737,831.21	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	538,858,083.00	2,032,588,750.94	0.00	2,571,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,703,903,664.42	(1,427,042,917.49)	0.00	276,860,746.93	0.00
AccumulatedOtherComprehensiveIncome Accumulated other compreh	(1,190,493.12)	1,494,447.62	0.00	303,954.50	0.00
Total equity	2,549,389,942.99	607,040,281.07	0.00	3,156,430,224.06	0.00
Total liabilities and equity	**6,707,929,266.65**	**679,506,105.00**	**0.00**	**7,387,435,371.65**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**6,707,929,266.65**	**679,506,105.00**	**0.00**	**7,387,435,371.65**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**6,707,929,266.65**	**679,506,105.00**	**0.00**	**7,387,435,371.65**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofSep 2014
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 10-07-14 Run Time: 2:01:07 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	21,906,570.37	0.00	0.00	21,906,570.37	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	126,489,573.42	0.00	0.00	126,489,573.42	0.00
OtherAR Other	7,896,505.73	0.00	0.00	7,896,505.73	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	49,140.80	0.00	0.00	49,140.80	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	73,271,844.80	0.00	0.00	73,271,844.80	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	125,415,578.81	0.00	0.00	125,415,578.81	0.00
Prepayments	8,805,530.50	0.00	0.00	8,805,530.50	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	(106,881.93)	0.00	0.00	(106,881.93)	0.00
RegulatoryCurrentAssets Regulatory assets	1,805,412.00	0.00	0.00	1,805,412.00	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,088,689.37	229,912.20	0.00	3,318,601.57	0.00
Total current assets	368,621,963.87	229,912.20	0.00	368,851,876.07	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,575,134,309.12	(1,781,954,634.64)	0.00	5,793,179,674.48	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,720.15	0.00	0.00	971,720.15	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,348,984,449.48)	1,781,954,634.77	(0.00)	(567,029,814.71)	(0.00)
ConstructionWorkInProgress Construction work in progress	897,229,830.73	(0.13)	0.00	897,229,830.60	0.00
Property, plant and equipment, net	6,124,351,410.52	0.00	0.00	6,124,351,410.52	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	171,864,775.07	4,011,674.58	0.00	175,876,449.65	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,516,128.03	69,424,047.36	0.00	82,940,175.39	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	2,804,902.73	0.00	0.00	2,804,902.73	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	62,978,233.92	(3,613,164.33)	0.00	59,365,069.59	0.00
Total other noncurrent assets	251,164,039.75	677,226,925.84	0.00	928,390,965.59	0.00
Total Assets	6,744,137,414.14	677,456,838.04	0.00	7,421,594,252.18	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	129,990,812.67	0.00	0.00	129,990,812.67	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	166,062,303.14	0.00	0.00	166,062,303.14	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	29,400,562.53	0.00	0.00	29,400,562.53	0.00
TaxesAccrued Taxes	20,853,703.27	0.00	0.00	20,853,703.27	0.00
InterestAccrued Interest	29,463,914.56	0.00	0.00	29,463,914.56	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	1,476,129.38	229,912.20	0.00	1,706,041.58	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,738,302.05	0.00	0.00	26,738,302.05	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	35,660,373.52	0.00	0.00	35,660,373.52	0.00
Total current liabilities	439,646,101.12	229,912.20	0.00	439,876,013.32	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,090,592,379.36	561,408.11	0.00	2,091,153,787.47	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,090,592,379.36	561,408.11	0.00	2,091,153,787.47	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	786,350,960.09	(218,387.69)	0.00	786,132,572.40	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,332,955.57	0.00	0.00	95,332,955.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	2,411,832.38	0.00	0.00	2,411,832.38	0.00
AccruedPensionObligations Accrued pension obligations	1,954,136.14	0.00	0.00	1,954,136.14	0.00
AssetRetirementObligations Asset retirement obligations	206,015,913.24	0.00	0.00	206,015,913.24	0.00
RegulatoryLiabilities Regulatory liabilities	469,299,233.12	69,424,047.36	0.00	538,723,280.48	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	89,053,574.50	398,510.25	0.00	89,452,084.75	0.00
	1,650,418,605.04	69,604,169.92	0.00	1,720,022,774.96	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	538,858,083.00	2,032,588,750.94	0.00	2,571,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,718,028,978.65	(1,427,024,720.67)	0.00	291,004,257.98	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(1,225,421.72)	1,497,317.54	0.00	271,895.82	0.00
Total equity	2,563,480,328.62	607,061,347.81	0.00	3,170,541,676.43	0.00
Total liabilities and equity	**6,744,137,414.14**	**677,456,838.04**	**0.00**	**7,421,594,252.18**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**6,744,137,414.14**	**677,456,838.04**	**0.00**	**7,421,594,252.18**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**6,744,137,414.14**	**677,456,838.04**	**0.00**	**7,421,594,252.18**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofOct 2014
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 11-07-14 Run Time: 6:02:13 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	12,908,863.24	0.00	0.00	12,908,863.24	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	113,781,132.71	0.00	0.00	113,781,132.71	0.00
OtherAR Other	6,946,208.63	0.00	0.00	6,946,208.63	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	23,154.07	0.00	0.00	23,154.07	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	69,781,949.37	0.00	0.00	69,781,949.37	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	135,894,892.03	0.00	0.00	135,894,892.03	0.00
Prepayments	7,495,599.51	0.00	0.00	7,495,599.51	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	(106,881.93)	0.00	0.00	(106,881.93)	0.00
RegulatoryCurrentAssets Regulatory assets	4,031,562.41	0.00	0.00	4,031,562.41	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,709,130.43	227,747.10	0.00	2,936,877.53	0.00
Total current assets	353,465,610.47	227,747.10	0.00	353,693,357.57	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,583,518,737.26	(1,780,754,748.54)	0.00	5,802,763,988.72	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,720.15	0.00	0.00	971,720.15	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,362,568,129.65)	1,780,754,748.67	(0.00)	(581,813,380.98)	(0.00)
ConstructionWorkInProgress Construction work in progress	939,095,109.43	(0.13)	0.00	939,095,109.30	0.00
Property, plant and equipment, net	6,161,017,437.19	0.00	0.00	6,161,017,437.19	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	179,066,900.41	3,935,693.00	0.00	183,002,593.41	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,490,293.78	67,435,884.92	0.00	80,926,178.70	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	2,359,144.20	0.00	0.00	2,359,144.20	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	63,182,397.06	(3,596,122.17)	0.00	59,586,274.89	0.00
Total other noncurrent assets	258,098,735.45	675,179,823.98	0.00	933,278,559.43	0.00
Total Assets	6,772,581,783.11	675,407,571.08	0.00	7,447,989,354.19	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	129,990,476.90	0.00	0.00	129,990,476.90	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	141,400,994.65	0.00	0.00	141,400,994.65	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	28,114,789.24	0.00	0.00	28,114,789.24	0.00
TaxesAccrued Taxes	26,650,637.43	0.00	0.00	26,650,637.43	0.00
InterestAccrued Interest	35,464,133.68	0.00	0.00	35,464,133.68	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	6,037,132.00	227,747.10	0.00	6,264,879.10	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,981,975.38	0.00	0.00	26,981,975.38	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	55,372,308.70	0.00	0.00	55,372,308.70	0.00
Total current liabilities	450,012,447.98	227,747.10	0.00	450,240,195.08	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,090,651,606.86	548,391.36	0.00	2,091,199,998.22	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,090,651,606.86	548,391.36	0.00	2,091,199,998.22	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	786,350,960.08	(206,639.15)	0.00	786,144,320.93	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,177,017.57	0.00	0.00	95,177,017.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	8,136,895.56	0.00	0.00	8,136,895.56	0.00
AccruedPensionObligations Accrued pension obligations	1,983,806.89	0.00	0.00	1,983,806.89	0.00
AssetRetirementObligations Asset retirement obligations	206,829,107.11	0.00	0.00	206,829,107.11	0.00
RegulatoryLiabilities Regulatory liabilities	467,997,320.79	67,435,884.92	0.00	535,433,205.71	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	89,992,309.70	339,570.83	0.00	90,331,880.53	0.00
	1,656,467,417.70	67,568,816.60	0.00	1,724,036,234.30	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	538,858,083.00	2,032,588,750.94	0.00	2,571,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,729,998,960.60	(1,427,006,267.32)	0.00	302,992,693.28	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(1,225,421.72)	1,480,132.40	0.00	254,710.68	0.00
Total equity	2,575,450,310.57	607,062,616.02	0.00	3,182,512,926.59	0.00
Total liabilities and equity	**6,772,581,783.11**	**675,407,571.08**	**0.00**	**7,447,989,354.19**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**6,772,581,783.11**	**675,407,571.08**	**0.00**	**7,447,989,354.19**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**6,772,581,783.11**	**675,407,571.08**	**0.00**	**7,447,989,354.19**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofNov 2014
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 12-05-14 Run Time: 6:21:57 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	22,457,414.57	0.00	0.00	22,457,414.57	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	107,630,248.06	0.00	0.00	107,630,248.06	0.00
OtherAR Other	6,162,509.34	0.00	0.00	6,162,509.34	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	23,154.07	0.00	0.00	23,154.07	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	93,373,635.68	0.00	0.00	93,373,635.68	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	141,843,425.22	0.00	0.00	141,843,425.22	0.00
Prepayments	6,259,162.09	0.00	0.00	6,259,162.09	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	311,056.62	0.00	0.00	311,056.62	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	(106,881.93)	0.00	0.00	(106,881.93)	0.00
RegulatoryCurrentAssets Regulatory assets	3,255,393.25	0.00	0.00	3,255,393.25	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,644,669.88	225,582.00	0.00	1,870,251.88	0.00
Total current assets	382,853,786.85	225,582.00	0.00	383,079,368.85	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,589,657,903.50	(1,780,128,514.28)	0.00	5,809,529,389.22	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,720.15	0.00	0.00	971,720.15	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,375,651,994.96)	1,780,128,514.41	(0.00)	(595,523,480.55)	(0.00)
ConstructionWorkInProgress Construction work in progress	976,593,996.60	(0.13)	0.00	976,593,996.47	0.00
Property, plant and equipment, net	6,191,571,625.29	0.00	0.00	6,191,571,625.29	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	193,765,240.40	3,859,711.42	0.00	197,624,951.82	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,464,478.69	65,447,722.48	0.00	78,912,201.17	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	63,153,668.30	(3,579,080.01)	0.00	59,574,588.29	0.00
Total other noncurrent assets	270,383,387.39	673,132,722.12	0.00	943,516,109.51	0.00
Total Assets	6,844,808,799.53	673,358,304.12	0.00	7,518,167,103.65	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	446,844,639.42	0.00	0.00	446,844,639.42	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	167,406,117.90	0.00	0.00	167,406,117.90	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	31,528,242.44	0.00	0.00	31,528,242.44	0.00
TaxesAccrued Taxes	26,508,274.12	0.00	0.00	26,508,274.12	0.00
InterestAccrued Interest	6,332,075.41	0.00	0.00	6,332,075.41	0.00
DividendsPayable Dividends	36,000,000.00	0.00	0.00	36,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	21,629,875.51	0.00	0.00	21,629,875.51	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	4,032,190.53	225,582.00	0.00	4,257,772.53	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	0.00	0.00	0.00	0.00	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	63,440,915.03	0.00	0.00	63,440,915.03	0.00
Total current liabilities	803,722,330.36	225,582.00	0.00	803,947,912.36	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,840,708,923.79	536,214.39	0.00	1,841,245,138.18	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,840,708,923.79	536,214.39	0.00	1,841,245,138.18	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	786,350,493.28	(195,217.29)	0.00	786,155,275.99	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,021,079.57	0.00	0.00	95,021,079.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	2,013,477.64	0.00	0.00	2,013,477.64	0.00
AssetRetirementObligations Asset retirement obligations	207,663,614.97	0.00	0.00	207,663,614.97	0.00
RegulatoryLiabilities Regulatory liabilities	465,127,194.70	65,447,722.48	0.00	530,574,917.18	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	90,120,269.37	280,631.41	0.00	90,400,900.78	0.00
	1,646,296,129.48	65,533,136.60	0.00	1,711,829,266.08	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	538,858,083.00	2,032,588,750.94	0.00	2,571,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,708,628,865.93	(1,426,988,327.07)	0.00	281,640,538.86	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(1,224,221.72)	1,462,947.26	0.00	238,725.54	0.00
Total equity	2,554,081,415.90	607,063,371.13	0.00	3,161,144,787.03	0.00
Total liabilities and equity	**6,844,808,799.53**	**673,358,304.12**	**0.00**	**7,518,167,103.65**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**6,844,808,799.53**	**673,358,304.12**	**0.00**	**7,518,167,103.65**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**6,844,808,799.53**	**673,358,304.12**	**0.00**	**7,518,167,103.65**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofDec 2014
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 01-21-15 Run Time: 5:50:14 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	11,136,662.57	0.00	0.00	11,136,662.57	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	124,621,855.74	0.00	0.00	124,621,855.74	0.00
OtherAR Other	66,312,555.43	0.00	0.00	66,312,555.43	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	23,154.07	0.00	0.00	23,154.07	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	91,068,106.97	0.00	0.00	91,068,106.97	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	148,511,587.26	0.00	0.00	148,511,587.26	0.00
Prepayments	7,629,373.84	0.00	0.00	7,629,373.84	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	1,522,869.99	0.00	0.00	1,522,869.99	0.00
RegulatoryCurrentAssets Regulatory assets	4,475,047.80	0.00	0.00	4,475,047.80	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,320,114.35	223,416.90	0.00	2,543,531.25	0.00
Total current assets	457,621,328.02	223,416.90	0.00	457,844,744.92	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,754,929,806.04	(1,778,411,081.61)	0.00	5,976,518,724.43	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,389,204,339.28)	1,778,411,081.74	(0.00)	(610,793,257.54)	(0.00)
ConstructionWorkInProgress Construction work in progress	880,068,808.98	(0.13)	0.00	880,068,808.85	0.00
Property, plant and equipment, net	6,246,765,588.84	0.00	0.00	6,246,765,588.84	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	264,119,360.68	3,783,729.88	0.00	267,903,090.56	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,438,682.76	63,459,560.00	0.00	76,898,242.76	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	61,398,957.38	(3,562,037.85)	0.00	57,836,919.53	0.00
Total other noncurrent assets	338,957,000.82	671,085,620.26	0.00	1,010,042,621.08	0.00
Total Assets	7,043,343,917.68	671,309,037.16	0.00	7,714,652,954.84	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	235,592,322.03	0.00	0.00	235,592,322.03	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	140,685,874.11	0.00	0.00	140,685,874.11	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	46,590,075.29	0.00	0.00	46,590,075.29	0.00
TaxesAccrued Taxes	14,040,602.11	0.00	0.00	14,040,602.11	0.00
InterestAccrued Interest	11,557,752.19	0.00	0.00	11,557,752.19	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	33,263,681.15	0.00	0.00	33,263,681.15	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	4,321,971.38	223,416.90	0.00	4,545,388.28	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	27,255,893.31	0.00	0.00	27,255,893.31	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	40,679,404.86	0.00	0.00	40,679,404.86	0.00
Total current liabilities	803,987,576.43	223,416.90	0.00	804,210,993.33	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,840,768,151.28	522,777.74	0.00	1,841,290,929.02	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,840,768,151.28	522,777.74	0.00	1,841,290,929.02	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	884,119,177.23	(203,360.46)	0.00	883,915,816.77	0.00
DeferredInvestmentTaxCredits Investment tax credits	94,865,139.57	0.00	0.00	94,865,139.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	58,866,214.88	0.00	0.00	58,866,214.88	0.00
AssetRetirementObligations Asset retirement obligations	208,146,697.63	0.00	0.00	208,146,697.63	0.00
RegulatoryLiabilities Regulatory liabilities	452,118,873.45	63,459,560.00	0.00	515,578,433.45	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	101,041,646.04	221,692.03	0.00	101,263,338.07	0.00
	1,799,157,748.75	63,477,891.57	0.00	1,862,635,640.32	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,728,986,178.85	(1,426,969,617.16)	0.00	302,016,561.69	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(1,232,509.32)	1,465,817.17	0.00	233,307.85	0.00
Total equity	2,599,430,441.22	607,084,950.95	0.00	3,206,515,392.17	0.00
Total liabilities and equity	**7,043,343,917.68**	**671,309,037.16**	**0.00**	**7,714,652,954.84**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,043,343,917.68**	**671,309,037.16**	**0.00**	**7,714,652,954.84**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,043,343,917.68**	**671,309,037.16**	**0.00**	**7,714,652,954.84**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofJan 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 02-06-15 Run Time: 11:45:06 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	9,609,577.89	0.00	0.00	9,609,577.89	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	150,595,217.96	0.00	0.00	150,595,217.96	0.00
OtherAR Other	51,782,402.75	0.00	0.00	51,782,402.75	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	43,830.70	0.00	0.00	43,830.70	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	96,955,131.80	0.00	0.00	96,955,131.80	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	141,156,637.49	0.00	0.00	141,156,637.49	0.00
Prepayments	9,071,291.61	0.00	0.00	9,071,291.61	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	1,522,869.99	0.00	0.00	1,522,869.99	0.00
RegulatoryCurrentAssets Regulatory assets	1,642,702.35	0.00	0.00	1,642,702.35	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,893,278.50	221,254.19	0.00	3,114,532.69	0.00
Total current assets	465,272,941.04	221,254.19	0.00	465,494,195.23	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,779,196,776.68	(1,778,169,793.26)	0.00	6,001,026,983.42	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,405,532,321.67)	1,778,169,793.39	(0.00)	(627,362,528.28)	(0.00)
ConstructionWorkInProgress Construction work in progress	885,833,207.40	(0.13)	0.00	885,833,207.27	0.00
Property, plant and equipment, net	6,260,468,975.51	0.00	0.00	6,260,468,975.51	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	312,103,870.15	3,755,629.29	0.00	315,859,499.44	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,412,886.83	61,267,971.99	0.00	74,680,858.82	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	61,151,669.82	(3,552,411.59)	0.00	57,599,258.23	0.00
Total other noncurrent assets	386,668,426.80	668,875,557.92	0.00	1,055,543,984.72	0.00
Total Assets	7,112,410,343.35	669,096,812.11	0.00	7,781,507,155.46	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	290,967,792.63	0.00	0.00	290,967,792.63	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	82,091,585.77	0.00	0.00	82,091,585.77	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	32,165,906.55	0.00	0.00	32,165,906.55	0.00
TaxesAccrued Taxes	9,271,027.82	0.00	0.00	9,271,027.82	0.00
InterestAccrued Interest	17,552,322.18	0.00	0.00	17,552,322.18	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	80,876,864.19	0.00	0.00	80,876,864.19	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	7,347,999.31	221,254.19	0.00	7,569,253.50	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	27,178,621.48	0.00	0.00	27,178,621.48	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	60,989,560.57	0.00	0.00	60,989,560.57	0.00
Total current liabilities	858,441,680.50	221,254.19	0.00	858,662,934.69	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,840,827,378.77	509,760.98	0.00	1,841,337,139.75	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,840,827,378.77	509,760.98	0.00	1,841,337,139.75	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	884,119,177.23	(191,611.92)	0.00	883,927,565.31	0.00
DeferredInvestmentTaxCredits Investment tax credits	94,709,201.57	0.00	0.00	94,709,201.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	44,363,179.17	0.00	0.00	44,363,179.17	0.00
AssetRetirementObligations Asset retirement obligations	208,994,762.47	0.00	0.00	208,994,762.47	0.00
RegulatoryLiabilities Regulatory liabilities	451,800,528.20	61,267,971.99	0.00	513,068,500.19	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	101,355,084.62	203,217.70	0.00	101,558,302.32	0.00
	1,785,341,933.21	61,279,577.77	0.00	1,846,621,510.98	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,757,355,088.50	(1,426,951,163.80)	0.00	330,403,924.70	0.00
AccumulatedOtherComprehensiveIncome Accumulated other compreh	(1,232,509.32)	1,448,632.03	0.00	216,122.71	0.00
Total equity	2,627,799,350.87	607,086,219.17	0.00	3,234,885,570.04	0.00
Total liabilities and equity	**7,112,410,343.35**	**669,096,812.11**	**0.00**	**7,781,507,155.46**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,112,410,343.35**	**669,096,812.11**	**0.00**	**7,781,507,155.46**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,112,410,343.35**	**669,096,812.11**	**0.00**	**7,781,507,155.46**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofFeb 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 03-06-15 Run Time: 11:46:25 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	14,374,683.41	0.00	0.00	14,374,683.41	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	158,811,148.19	0.00	0.00	158,811,148.19	0.00
OtherAR Other	39,194,404.56	0.00	0.00	39,194,404.56	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	19,224.21	0.00	0.00	19,224.21	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	104,768,232.14	0.00	0.00	104,768,232.14	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	134,380,054.60	0.00	0.00	134,380,054.60	0.00
Prepayments	9,259,755.88	0.00	0.00	9,259,755.88	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	4,800,752.53	0.00	0.00	4,800,752.53	0.00
RegulatoryCurrentAssets Regulatory assets	1,127,356.90	0.00	0.00	1,127,356.90	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,354,569.26	219,091.48	0.00	3,573,660.74	0.00
Total current assets	470,090,181.68	219,091.48	0.00	470,309,273.16	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,802,931,210.66	(1,775,276,512.03)	0.00	6,027,654,698.63	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,411,509,184.24)	1,775,276,512.16	(0.00)	(636,232,672.08)	(0.00)
ConstructionWorkInProgress Construction work in progress	888,751,923.15	(0.13)	0.00	888,751,923.02	0.00
Property, plant and equipment, net	6,281,145,262.67	0.00	0.00	6,281,145,262.67	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	283,675,304.84	3,721,594.62	0.00	287,396,899.46	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,387,090.90	59,076,383.98	0.00	72,463,474.88	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	58,847,569.66	(3,536,851.25)	0.00	55,310,718.41	0.00
Total other noncurrent assets	355,909,965.40	666,665,495.58	0.00	1,022,575,460.98	0.00
Total Assets	7,107,145,409.75	666,884,587.06	0.00	7,774,029,996.81	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	264,890,745.65	0.00	0.00	264,890,745.65	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	96,556,086.02	0.00	0.00	96,556,086.02	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	35,212,922.28	0.00	0.00	35,212,922.28	0.00
TaxesAccrued Taxes	10,699,427.28	0.00	0.00	10,699,427.28	0.00
InterestAccrued Interest	23,544,308.53	0.00	0.00	23,544,308.53	0.00
DividendsPayable Dividends	30,000,000.00	0.00	0.00	30,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	52,129,986.14	0.00	0.00	52,129,986.14	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	9,308,508.08	219,091.48	0.00	9,527,599.56	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	27,274,071.04	0.00	0.00	27,274,071.04	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	42,883,965.67	0.00	0.00	42,883,965.67	0.00
Total current liabilities	842,500,020.69	219,091.48	0.00	842,719,112.17	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,840,880,874.57	498,003.92	0.00	1,841,378,878.49	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,840,880,874.57	498,003.92	0.00	1,841,378,878.49	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	893,603,966.26	(180,353.41)	0.00	893,423,612.85	0.00
DeferredInvestmentTaxCredits Investment tax credits	94,553,263.57	0.00	0.00	94,553,263.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	44,420,830.88	0.00	0.00	44,420,830.88	0.00
AssetRetirementObligations Asset retirement obligations	209,841,570.83	0.00	0.00	209,841,570.83	0.00
RegulatoryLiabilities Regulatory liabilities	452,611,293.86	59,076,383.98	0.00	511,687,677.84	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	101,427,706.02	184,743.37	0.00	101,612,449.39	0.00
	1,796,458,631.37	59,080,773.94	0.00	1,855,539,405.31	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,756,861,620.75	(1,426,933,480.11)	0.00	329,928,140.64	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(1,232,509.32)	1,431,446.89	0.00	198,937.57	0.00
Total equity	2,627,305,883.12	607,086,717.72	0.00	3,234,392,600.84	0.00
Total liabilities and equity	**7,107,145,409.75**	**666,884,587.06**	**0.00**	**7,774,029,996.81**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,107,145,409.75**	**666,884,587.06**	**0.00**	**7,774,029,996.81**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,107,145,409.75**	**666,884,587.06**	**0.00**	**7,774,029,996.81**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofMar 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 04-08-15 Run Time: 11:12:58 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	22,656,449.88	0.00	0.00	22,656,449.88	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	147,661,005.75	0.00	0.00	147,661,005.75	0.00
OtherAR Other	4,905,133.20	0.00	0.00	4,905,133.20	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	3,780.56	0.00	0.00	3,780.56	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	76,787,614.30	0.00	0.00	76,787,614.30	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	133,724,996.32	0.00	0.00	133,724,996.32	0.00
Prepayments	7,073,562.72	0.00	0.00	7,073,562.72	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	6,629,991.88	0.00	0.00	6,629,991.88	0.00
RegulatoryCurrentAssets Regulatory assets	8,135,737.45	0.00	0.00	8,135,737.45	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,737,857.14	216,928.77	0.00	3,954,785.91	0.00
Total current assets	411,316,129.20	216,928.77	0.00	411,533,057.97	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,815,619,031.61	(1,762,696,048.95)	0.00	6,052,922,982.66	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant an	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,414,180,812.40)	1,762,696,049.08	(0.00)	(651,484,763.32)	(0.00)
ConstructionWorkInProgress Construction work in progress	907,825,685.31	(0.13)	0.00	907,825,685.18	0.00
Property, plant and equipment, net	6,310,235,217.62	0.00	0.00	6,310,235,217.62	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	293,278,415.32	3,685,895.52	0.00	296,964,310.84	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,361,294.97	56,884,795.97	0.00	70,246,090.94	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	60,665,614.32	(3,519,626.48)	0.00	57,145,987.84	0.00
Total other noncurrent assets	367,305,324.61	664,455,433.24	0.00	1,031,760,757.85	0.00
Total Assets	7,088,856,671.43	664,672,362.01	0.00	7,753,529,033.44	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	192,947,747.17	0.00	0.00	192,947,747.17	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	113,492,202.58	0.00	0.00	113,492,202.58	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	33,345,532.72	0.00	0.00	33,345,532.72	0.00
TaxesAccrued Taxes	13,389,594.00	0.00	0.00	13,389,594.00	0.00
InterestAccrued Interest	29,573,836.24	0.00	0.00	29,573,836.24	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	61,374,656.90	0.00	0.00	61,374,656.90	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	9,939,818.96	216,928.77	0.00	10,156,747.73	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	27,238,382.69	0.00	0.00	27,238,382.69	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	44,217,218.61	0.00	0.00	44,217,218.61	0.00
Total current liabilities	775,518,989.87	216,928.77	0.00	775,735,918.64	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,840,940,102.07	484,987.15	0.00	1,841,425,089.22	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,840,940,102.07	484,987.15	0.00	1,841,425,089.22	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	932,913,538.83	(188,659.92)	0.00	932,724,878.91	0.00
DeferredInvestmentTaxCredits Investment tax credits	94,403,589.57	0.00	0.00	94,403,589.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	44,548,138.88	0.00	0.00	44,548,138.88	0.00
AssetRetirementObligations Asset retirement obligations	201,992,000.99	0.00	0.00	201,992,000.99	0.00
RegulatoryLiabilities Regulatory liabilities	450,627,643.76	56,884,795.97	0.00	507,512,439.73	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	101,125,645.79	166,269.04	0.00	101,291,914.83	0.00
	1,825,610,557.77	56,862,405.09	0.00	1,882,472,962.86	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,777,247,894.75	(1,426,915,026.75)	0.00	350,332,868.00	0.00
AccumulatedOtherComprehensiveIncome Accumulated other compreh	(2,137,644.72)	1,434,316.81	0.00	(703,327.91)	0.00
Total equity	2,646,787,021.72	607,108,041.00	0.00	3,253,895,062.72	0.00
Total liabilities and equity	**7,088,856,671.43**	**664,672,362.01**	**0.00**	**7,753,529,033.44**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,088,856,671.43**	**664,672,362.01**	**0.00**	**7,753,529,033.44**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,088,856,671.43**	**664,672,362.01**	**0.00**	**7,753,529,033.44**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofApr 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 05-07-15 Run Time: 11:22:14 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	7,457,525.53	0.00	0.00	7,457,525.53	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	127,881,166.63	0.00	0.00	127,881,166.63	0.00
OtherAR Other	3,123,357.32	0.00	0.00	3,123,357.32	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	176,601.56	0.00	0.00	176,601.56	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	67,338,921.13	0.00	0.00	67,338,921.13	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	139,900,504.56	0.00	0.00	139,900,504.56	0.00
Prepayments	10,488,582.86	0.00	0.00	10,488,582.86	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	6,629,991.88	0.00	0.00	6,629,991.88	0.00
RegulatoryCurrentAssets Regulatory assets	11,748,765.00	0.00	0.00	11,748,765.00	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,805,011.36	214,766.06	0.00	4,019,777.42	0.00
Total current assets	378,550,427.83	214,766.06	0.00	378,765,193.89	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,820,251,832.63	(1,751,791,495.05)	0.00	6,068,460,337.58	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,419,710,091.98)	1,751,791,495.18	(0.00)	(667,918,596.80)	(0.00)
ConstructionWorkInProgress Construction work in progress	932,187,569.90	(0.13)	0.00	932,187,569.77	0.00
Property, plant and equipment, net	6,333,700,623.65	0.00	0.00	6,333,700,623.65	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	283,824,794.59	3,650,750.09	0.00	287,475,544.68	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,335,499.04	54,693,207.96	0.00	68,028,707.00	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	61,020,527.53	(3,502,955.38)	0.00	57,517,572.15	0.00
Total other noncurrent assets	358,180,821.16	662,245,370.90	0.00	1,020,426,192.06	0.00
Total Assets	7,070,431,872.64	662,460,136.96	0.00	7,732,892,009.60	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	150,011,667.76	0.00	0.00	150,011,667.76	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	116,082,404.73	0.00	0.00	116,082,404.73	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	40,537,871.10	0.00	0.00	40,537,871.10	0.00
TaxesAccrued Taxes	26,817,706.21	0.00	0.00	26,817,706.21	0.00
InterestAccrued Interest	35,571,581.13	0.00	0.00	35,571,581.13	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	51,641,508.11	0.00	0.00	51,641,508.11	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	9,420,534.30	214,766.06	0.00	9,635,300.36	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	27,159,704.31	0.00	0.00	27,159,704.31	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	44,241,468.20	0.00	0.00	44,241,468.20	0.00
Total current liabilities	751,484,445.85	214,766.06	0.00	751,699,211.91	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,840,997,418.99	472,390.30	0.00	1,841,469,809.29	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,840,997,418.99	472,390.30	0.00	1,841,469,809.29	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	932,913,538.83	(177,074.73)	0.00	932,736,464.10	0.00
DeferredInvestmentTaxCredits Investment tax credits	94,249,739.57	0.00	0.00	94,249,739.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	44,675,446.88	0.00	0.00	44,675,446.88	0.00
AssetRetirementObligations Asset retirement obligations	202,844,633.93	0.00	0.00	202,844,633.93	0.00
RegulatoryLiabilities Regulatory liabilities	450,403,734.68	54,693,207.96	0.00	505,096,942.64	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	101,334,267.66	147,794.71	0.00	101,482,062.37	0.00
	1,826,421,361.50	54,663,927.94	0.00	1,881,085,289.44	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,781,989,519.33	(1,426,896,829.95)	0.00	355,092,689.38	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(2,137,644.72)	1,417,131.67	0.00	(720,513.05)	0.00
Total equity	2,651,528,646.30	607,109,052.66	0.00	3,258,637,698.96	0.00
Total liabilities and equity	**7,070,431,872.64**	**662,460,136.96**	**0.00**	**7,732,892,009.60**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,070,431,872.64**	**662,460,136.96**	**0.00**	**7,732,892,009.60**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,070,431,872.64**	**662,460,136.96**	**0.00**	**7,732,892,009.60**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofMay 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 06-05-15 Run Time: 11:53:21 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	8,737,820.64	0.00	0.00	8,737,820.64	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	113,098,972.00	0.00	0.00	113,098,972.00	0.00
OtherAR Other	4,705,912.58	0.00	0.00	4,705,912.58	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	0.00	0.00	0.00	0.00	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	82,308,977.72	0.00	0.00	82,308,977.72	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	144,111,831.82	0.00	0.00	144,111,831.82	0.00
Prepayments	9,575,108.78	0.00	0.00	9,575,108.78	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	6,629,991.88	0.00	0.00	6,629,991.88	0.00
RegulatoryCurrentAssets Regulatory assets	13,049,163.55	0.00	0.00	13,049,163.55	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,983,664.22	212,603.35	0.00	4,196,267.57	0.00
Total current assets	386,201,443.19	212,603.35	0.00	386,414,046.54	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	7,978,718,216.63	(1,745,389,071.30)	0.00	6,233,329,145.33	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,417,078,730.82)	1,745,389,071.43	(0.00)	(671,689,659.39)	(0.00)
ConstructionWorkInProgress Construction work in progress	790,882,245.01	(0.13)	0.00	790,882,244.88	0.00
Property, plant and equipment, net	6,353,493,043.92	0.00	0.00	6,353,493,043.92	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	276,901,268.33	3,615,052.13	0.00	280,516,320.46	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,309,703.11	52,501,619.95	0.00	65,811,323.06	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	60,874,635.97	(3,485,731.75)	0.00	57,388,904.22	0.00
Total other noncurrent assets	351,085,607.41	660,035,308.56	0.00	1,011,120,915.97	0.00
Total Assets	7,090,780,094.52	660,247,911.91	0.00	7,751,028,006.43	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	192,912,103.55	0.00	0.00	192,912,103.55	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	108,880,741.41	0.00	0.00	108,880,741.41	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	33,482,611.06	0.00	0.00	33,482,611.06	0.00
TaxesAccrued Taxes	38,379,559.05	0.00	0.00	38,379,559.05	0.00
InterestAccrued Interest	6,389,477.61	0.00	0.00	6,389,477.61	0.00
DividendsPayable Dividends	51,000,000.00	0.00	0.00	51,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	43,172,679.20	0.00	0.00	43,172,679.20	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	9,909,248.25	212,603.35	0.00	10,121,851.60	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,924,126.01	0.00	0.00	26,924,126.01	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	46,222,605.24	0.00	0.00	46,222,605.24	0.00
Total current liabilities	807,273,151.38	212,603.35	0.00	807,485,754.73	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,841,056,646.48	459,373.53	0.00	1,841,516,020.01	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,841,056,646.48	459,373.53	0.00	1,841,516,020.01	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	932,913,616.63	(165,326.18)	0.00	932,748,290.45	0.00
DeferredInvestmentTaxCredits Investment tax credits	94,095,889.57	0.00	0.00	94,095,889.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	45,515,050.99	0.00	0.00	45,515,050.99	0.00
AssetRetirementObligations Asset retirement obligations	203,701,821.56	0.00	0.00	203,701,821.56	0.00
RegulatoryLiabilities Regulatory liabilities	450,240,757.42	52,501,619.95	0.00	502,742,377.37	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	100,538,242.71	129,320.38	0.00	100,667,563.09	0.00
	1,827,005,378.83	52,465,614.15	0.00	1,879,470,992.98	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,745,905,990.86	(1,426,878,376.59)	0.00	319,027,614.27	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(2,137,844.72)	1,399,946.53	0.00	(737,898.19)	0.00
Total equity	2,615,444,917.83	607,110,320.88	0.00	3,222,555,238.71	0.00
Total liabilities and equity	**7,090,780,094.52**	**660,247,911.91**	**0.00**	**7,751,028,006.43**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,090,780,094.52**	**660,247,911.91**	**0.00**	**7,751,028,006.43**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,090,780,094.52**	**660,247,911.91**	**0.00**	**7,751,028,006.43**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofJun 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 07-08-15 Run Time: 11:14:55 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	6,036,919.69	0.00	0.00	6,036,919.69	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	122,028,493.44	0.00	0.00	122,028,493.44	0.00
OtherAR Other	7,374,766.62	0.00	0.00	7,374,766.62	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	2,475.15	0.00	0.00	2,475.15	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	87,739,513.87	0.00	0.00	87,739,513.87	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	146,569,674.97	0.00	0.00	146,569,674.97	0.00
Prepayments	11,365,369.57	0.00	0.00	11,365,369.57	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	132,969.39	0.00	0.00	132,969.39	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	19,503,822.43	0.00	0.00	19,503,822.43	0.00
RegulatoryCurrentAssets Regulatory assets	13,614,270.00	0.00	0.00	13,614,270.00	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	4,090,708.14	210,440.64	0.00	4,301,148.78	0.00
Total current assets	418,458,983.27	210,440.64	0.00	418,669,423.91	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,523,495,208.41	(1,744,656,686.99)	0.00	6,778,838,521.42	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	971,313.10	0.00	0.00	971,313.10	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,429,712,550.81)	1,744,656,687.12	(0.00)	(685,055,863.69)	(0.00)
ConstructionWorkInProgress Construction work in progress	390,314,896.82	(0.13)	0.00	390,314,896.69	0.00
Property, plant and equipment, net	6,485,068,867.52	0.00	0.00	6,485,068,867.52	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	248,974,694.47	3,579,910.67	0.00	252,554,605.14	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,283,907.18	50,310,031.94	0.00	63,593,939.12	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	60,652,521.85	(3,469,064.62)	0.00	57,183,457.23	0.00
Total other noncurrent assets	322,911,123.50	657,825,246.22	0.00	980,736,369.72	0.00
Total Assets	7,226,438,974.29	658,035,686.86	0.00	7,884,474,661.15	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	226,951,047.46	0.00	0.00	226,951,047.46	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	123,834,597.13	0.00	0.00	123,834,597.13	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	35,866,268.59	0.00	0.00	35,866,268.59	0.00
TaxesAccrued Taxes	28,233,991.29	0.00	0.00	28,233,991.29	0.00
InterestAccrued Interest	11,683,017.88	0.00	0.00	11,683,017.88	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	22,658,339.84	0.00	0.00	22,658,339.84	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	11,937,253.81	210,440.64	0.00	12,147,694.45	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,798,081.70	0.00	0.00	26,798,081.70	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	41,539,190.56	0.00	0.00	41,539,190.56	0.00
Total current liabilities	779,501,788.26	210,440.64	0.00	779,712,228.90	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,841,113,963.42	446,776.68	0.00	1,841,560,740.10	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,841,113,963.42	446,776.68	0.00	1,841,560,740.10	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	987,570,591.61	(173,796.07)	0.00	987,396,795.54	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,942,039.57	0.00	0.00	93,942,039.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	43,364,087.88	0.00	0.00	43,364,087.88	0.00
AssetRetirementObligations Asset retirement obligations	327,718,047.29	0.00	0.00	327,718,047.29	0.00
RegulatoryLiabilities Regulatory liabilities	454,749,980.08	50,310,031.94	0.00	505,060,012.02	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	63,768,501.41	110,846.05	0.00	63,879,347.46	0.00
	1,971,113,247.79	50,247,081.92	0.00	2,021,360,329.71	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,765,169,748.05	(1,426,860,179.78)	0.00	338,309,568.27	0.00
AccumulatedOtherComprehensiveIncome Accumulated other compreh	(2,136,544.92)	1,402,816.46	0.00	(733,728.46)	0.00
Total equity	2,634,709,974.82	607,131,387.62	0.00	3,241,841,362.44	0.00
Total liabilities and equity	**7,226,438,974.29**	**658,035,686.86**	**0.00**	**7,884,474,661.15**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,226,438,974.29**	**658,035,686.86**	**0.00**	**7,884,474,661.15**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,226,438,974.29**	**658,035,686.86**	**0.00**	**7,884,474,661.15**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofJul 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 08-07-15 Run Time: 11:40:11 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	)119 Kentucky Utilities Company Purchase Acctg A	Eliminations	110_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	4,816,560.02	0.00	0.00	4,816,560.02	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	135,846,748.52	0.00	0.00	135,846,748.52	0.00
OtherAR Other	6,415,733.30	0.00	0.00	6,415,733.30	0.00
AccountsReceivableFromAffiliates Accounts receivable from affiliates	548.73	0.00	0.00	548.73	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	89,020,527.26	0.00	0.00	89,020,527.26	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	141,718,515.38	0.00	0.00	141,718,515.38	0.00
Prepayments	9,889,894.18	0.00	0.00	9,889,894.18	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	19,503,822.43	0.00	0.00	19,503,822.43	0.00
RegulatoryCurrentAssets Regulatory assets	14,235,045.33	0.00	0.00	14,235,045.33	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,657,189.90	208,277.93	0.00	3,865,467.83	0.00
Total current assets	425,104,585.05	208,277.93	0.00	425,312,862.98	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,535,178,207.06	(1,744,097,103.23)	0.00	6,791,081,103.83	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, plant anc	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation - regula	(2,445,376,523.08)	1,744,097,103.36	(0.00)	(701,279,419.72)	(0.00)
ConstructionWorkInProgress Construction work in progress	402,574,979.11	(0.13)	0.00	402,574,978.98	0.00
Property, plant and equipment, net	6,492,376,663.09	0.00	0.00	6,492,376,663.09	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	270,852,951.97	3,544,195.97	0.00	274,397,147.94	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,258,111.25	48,118,443.93	0.00	61,376,555.18	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	61,099,452.31	(3,451,824.25)	0.00	57,647,628.06	0.00
Total other noncurrent assets	345,210,515.53	655,615,183.88	0.00	1,000,825,699.41	0.00
Total Assets	7,262,691,763.67	655,823,461.81	0.00	7,918,515,225.48	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	210,884,216.98	0.00	0.00	210,884,216.98	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one year	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	110,533,331.99	0.00	0.00	110,533,331.99	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	28,777,148.32	0.00	0.00	28,777,148.32	0.00
TaxesAccrued Taxes	46,500,802.58	0.00	0.00	46,500,802.58	0.00
InterestAccrued Interest	17,679,327.81	0.00	0.00	17,679,327.81	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	40,683,666.27	0.00	0.00	40,683,666.27	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	14,619,674.65	208,277.93	0.00	14,827,952.58	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayments	26,491,600.15	0.00	0.00	26,491,600.15	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	42,595,567.31	0.00	0.00	42,595,567.31	0.00
Total current liabilities	788,765,336.06	208,277.93	0.00	788,973,613.99	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,841,173,190.91	433,759.91	0.00	1,841,606,950.82	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,841,173,190.91	433,759.91	0.00	1,841,606,950.82	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	987,570,591.61	(162,047.52)	0.00	987,408,544.09	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,788,189.57	0.00	0.00	93,788,189.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	43,952,951.04	0.00	0.00	43,952,951.04	0.00
AssetRetirementObligations Asset retirement obligations	328,838,027.21	0.00	0.00	328,838,027.21	0.00
RegulatoryLiabilities Regulatory liabilities	454,201,394.07	48,118,443.93	0.00	502,319,838.00	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurrent liabili	64,115,118.93	92,371.72	0.00	64,207,490.65	0.00
	1,972,466,272.38	48,048,768.13	0.00	2,020,515,040.51	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,790,746,737.55	(1,426,841,726.42)	0.00	363,905,011.13	0.00
AccumulatedOtherComprehensiveIncome Accumulated other comprel	(2,136,544.92)	1,385,631.32	0.00	(750,913.60)	0.00
Total equity	2,660,286,964.32	607,132,655.84	0.00	3,267,419,620.16	0.00
Total liabilities and equity	**7,262,691,763.67**	**655,823,461.81**	**0.00**	**7,918,515,225.48**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,262,691,763.67**	**655,823,461.81**	**0.00**	**7,918,515,225.48**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' Equity	**7,262,691,763.67**	**655,823,461.81**	**0.00**	**7,918,515,225.48**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofAug 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 09-08-15 Run Time: 2:00:30 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	10,163,364.61	0.00	0.00	10,163,364.61	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	134,261,778.20	0.00	0.00	134,261,778.20	0.00
OtherAR Other	5,400,734.45	0.00	0.00	5,400,734.45	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	0.00	0.00	0.00	0.00	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	90,812,898.78	0.00	0.00	90,812,898.78	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	138,352,704.27	0.00	0.00	138,352,704.27	0.00
Prepayments	8,597,350.84	0.00	0.00	8,597,350.84	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	19,645,528.51	0.00	0.00	19,645,528.51	0.00
RegulatoryCurrentAssets Regulatory assets	15,377,179.36	0.00	0.00	15,377,179.36	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,318,255.55	206,115.22	0.00	3,524,370.77	0.00
Total current assets	425,929,794.57	206,115.22	0.00	426,135,909.79	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,552,182,567.27	(1,734,310,922.33)	0.00	6,817,871,644.94	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,445,107,464.05)	1,734,310,922.46	(0.00)	(710,796,541.59)	(0.00)
ConstructionWorkInProgress Construction work in progress	400,615,598.72	(0.13)	0.00	400,615,598.59	0.00
Property, plant and equipment, net	6,507,690,701.94	0.00	0.00	6,507,690,701.94	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	273,465,150.46	3,508,488.25	0.00	276,973,638.71	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,232,315.32	45,926,855.92	0.00	59,159,171.24	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	61,605,992.96	(3,434,590.86)	0.00	58,171,402.10	0.00
Total other noncurrent assets	348,303,458.74	653,405,121.54	0.00	1,001,708,580.28	0.00
Total Assets	7,281,923,955.25	653,611,236.76	0.00	7,935,535,192.01	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	213,987,852.02	0.00	0.00	213,987,852.02	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	88,284,350.85	0.00	0.00	88,284,350.85	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	24,538,008.58	0.00	0.00	24,538,008.58	0.00
TaxesAccrued Taxes	65,243,671.17	0.00	0.00	65,243,671.17	0.00
InterestAccrued Interest	23,469,025.70	0.00	0.00	23,469,025.70	0.00
DividendsPayable Dividends	25,000,000.00	0.00	0.00	25,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	40,746,157.63	0.00	0.00	40,746,157.63	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	14,229,773.66	206,115.22	0.00	14,435,888.88	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayı	26,302,851.05	0.00	0.00	26,302,851.05	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	35,422,112.34	0.00	0.00	35,422,112.34	0.00
Total current liabilities	807,223,803.00	206,115.22	0.00	807,429,918.22	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	1,841,232,418.40	420,743.16	0.00	1,841,653,161.56	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	1,841,232,418.40	420,743.16	0.00	1,841,653,161.56	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	987,336,482.53	(150,298.98)	0.00	987,186,183.55	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,634,339.57	0.00	0.00	93,634,339.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	(0.05)	0.00	0.00	(0.05)	0.00
AccruedPensionObligations Accrued pension obligations	43,628,321.88	0.00	0.00	43,628,321.88	0.00
AssetRetirementObligations Asset retirement obligations	330,019,159.70	0.00	0.00	330,019,159.70	0.00
RegulatoryLiabilities Regulatory liabilities	454,361,447.38	45,926,855.92	0.00	500,288,303.30	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	63,400,903.41	73,897.39	0.00	63,474,800.80	0.00
	1,972,380,654.42	45,850,454.33	0.00	2,018,231,108.75	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,791,547,052.66	(1,426,823,273.07)	0.00	364,723,779.59	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(2,136,744.92)	1,368,446.18	0.00	(768,298.74)	0.00
Total equity	2,661,087,079.43	607,133,924.05	0.00	3,268,221,003.48	0.00
Total liabilities and equity	**7,281,923,955.25**	**653,611,236.76**	**0.00**	**7,935,535,192.01**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,281,923,955.25**	**653,611,236.76**	**0.00**	**7,935,535,192.01**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,281,923,955.25**	**653,611,236.76**	**0.00**	**7,935,535,192.01**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofSep 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 10-07-15 Run Time: 11:59:56 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	274,892,013.95	0.00	0.00	274,892,013.95	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	130,557,494.36	0.00	0.00	130,557,494.36	0.00
OtherAR Other	4,804,204.63	0.00	0.00	4,804,204.63	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	6,287.80	0.00	0.00	6,287.80	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	85,101,992.86	0.00	0.00	85,101,992.86	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	127,108,344.44	0.00	0.00	127,108,344.44	0.00
Prepayments	7,469,212.46	0.00	0.00	7,469,212.46	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	29,913,279.14	0.00	0.00	29,913,279.14	0.00
RegulatoryCurrentAssets Regulatory assets	15,558,886.39	0.00	0.00	15,558,886.39	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,597,703.00	203,952.51	0.00	2,801,655.51	0.00
Total current assets	678,009,419.03	203,952.51	0.00	678,213,371.54	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,523,298,496.94	(1,695,567,203.90)	0.00	6,827,731,293.04	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,405,353,144.63)	1,695,567,204.03	(0.00)	(709,785,940.60)	(0.00)
ConstructionWorkInProgress Construction work in progress	421,292,849.37	(0.13)	0.00	421,292,849.24	0.00
Property, plant and equipment, net	6,539,238,201.68	0.00	0.00	6,539,238,201.68	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	285,541,096.87	3,473,336.31	0.00	289,014,433.18	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,206,519.39	43,735,267.91	0.00	56,941,787.30	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	64,159,400.73	(3,417,913.25)	0.00	60,741,487.48	0.00
Total other noncurrent assets	362,907,016.99	651,195,059.20	0.00	1,014,102,076.19	0.00
Total Assets	7,580,154,637.70	651,399,011.71	0.00	8,231,553,649.41	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	(0.06)	0.00	0.00	(0.06)	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	77,282,666.24	0.00	0.00	77,282,666.24	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	40,966,804.31	0.00	0.00	40,966,804.31	0.00
TaxesAccrued Taxes	22,873,930.80	0.00	0.00	22,873,930.80	0.00
InterestAccrued Interest	29,664,751.00	0.00	0.00	29,664,751.00	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	15,786,552.30	203,952.51	0.00	15,990,504.81	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	26,165,653.70	0.00	0.00	26,165,653.70	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	51,601,005.93	0.00	0.00	51,601,005.93	0.00
Total current liabilities	514,341,364.22	203,952.51	0.00	514,545,316.73	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,340,974,880.34	408,146.29	0.00	2,341,383,026.63	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,340,974,880.34	408,146.29	0.00	2,341,383,026.63	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,047,850,752.25	(158,768.85)	0.00	1,047,691,983.40	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,480,489.57	0.00	0.00	93,480,489.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	43,760,438.22	0.00	0.00	43,760,438.22	0.00
AssetRetirementObligations Asset retirement obligations	341,029,281.64	0.00	0.00	341,029,281.64	0.00
RegulatoryLiabilities Regulatory liabilities	454,186,201.55	43,735,267.91	0.00	497,921,469.46	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	63,047,023.34	55,423.06	0.00	63,102,446.40	0.00
	2,043,354,186.57	43,631,922.12	0.00	2,086,986,108.69	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,811,942,880.00	(1,426,805,076.24)	0.00	385,137,803.76	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(2,135,445.12)	1,371,316.09	0.00	(764,129.03)	0.00
Total equity	2,681,484,206.57	607,154,990.79	0.00	3,288,639,197.36	0.00
Total liabilities and equity	**7,580,154,637.70**	**651,399,011.71**	**0.00**	**8,231,553,649.41**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,580,154,637.70**	**651,399,011.71**	**0.00**	**8,231,553,649.41**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,580,154,637.70**	**651,399,011.71**	**0.00**	**8,231,553,649.41**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofOct 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 11-06-15 Run Time: 11:35:44 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	302,097,465.84	0.00	0.00	302,097,465.84	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	116,866,876.74	0.00	0.00	116,866,876.74	0.00
OtherAR Other	5,714,371.69	0.00	0.00	5,714,371.69	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	(147,868.40)	0.00	0.00	(147,868.40)	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	79,533,816.12	0.00	0.00	79,533,816.12	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	140,568,465.93	0.00	0.00	140,568,465.93	0.00
Prepayments	6,421,417.80	0.00	0.00	6,421,417.80	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	29,913,279.14	0.00	0.00	29,913,279.14	0.00
RegulatoryCurrentAssets Regulatory assets	17,184,495.42	0.00	0.00	17,184,495.42	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,311,275.66	201,789.80	0.00	2,513,065.46	0.00
Total current assets	700,463,595.94	201,789.80	0.00	700,665,385.74	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,536,440,751.18	(1,694,561,094.08)	0.00	6,841,879,657.10	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,423,587,027.92)	1,694,561,094.21	(0.00)	(729,025,933.71)	(0.00)
ConstructionWorkInProgress Construction work in progress	453,464,760.23	(0.13)	0.00	453,464,760.10	0.00
Property, plant and equipment, net	6,566,318,483.49	0.00	0.00	6,566,318,483.49	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	289,917,507.58	3,437,623.65	0.00	293,355,131.23	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,180,723.46	41,543,679.90	0.00	54,724,403.36	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	64,689,383.56	(3,400,674.92)	0.00	61,288,708.64	0.00
Total other noncurrent assets	367,787,614.60	648,984,996.86	0.00	1,016,772,611.46	0.00
Total Assets	7,634,569,694.03	649,186,786.66	0.00	8,283,756,480.69	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	0.00	0.00	0.00	0.00	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	250,000,000.00	0.00	0.00	250,000,000.00	0.00
AccountsPayable Accounts payable	98,669,866.97	0.00	0.00	98,669,866.97	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	45,292,780.78	0.00	0.00	45,292,780.78	0.00
TaxesAccrued Taxes	20,287,650.23	0.00	0.00	20,287,650.23	0.00
InterestAccrued Interest	37,143,169.96	0.00	0.00	37,143,169.96	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	19,211,954.28	201,789.80	0.00	19,413,744.08	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	26,329,001.76	0.00	0.00	26,329,001.76	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	60,042,970.67	0.00	0.00	60,042,970.67	0.00
Total current liabilities	556,977,394.65	201,789.80	0.00	557,179,184.45	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,341,035,649.61	395,129.54	0.00	2,341,430,779.15	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,341,035,649.61	395,129.54	0.00	2,341,430,779.15	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,047,850,752.25	(147,020.31)	0.00	1,047,703,731.94	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,326,639.57	0.00	0.00	93,326,639.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	44,059,242.29	0.00	0.00	44,059,242.29	0.00
AssetRetirementObligations Asset retirement obligations	342,074,427.36	0.00	0.00	342,074,427.36	0.00
RegulatoryLiabilities Regulatory liabilities	452,347,846.24	41,543,679.90	0.00	493,891,526.14	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	63,515,019.07	36,948.73	0.00	63,551,967.80	0.00
	2,043,173,926.78	41,433,608.32	0.00	2,084,607,535.10	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,823,841,396.42	(1,426,786,622.89)	0.00	397,054,773.53	0.00
AccumulatedOtherComprehensiveIncome Accumulated other co	(2,135,445.12)	1,354,130.95	0.00	(781,314.17)	0.00
Total equity	2,693,382,722.99	607,156,259.00	0.00	3,300,538,981.99	0.00
Total liabilities and equity	**7,634,569,694.03**	**649,186,786.66**	**0.00**	**8,283,756,480.69**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,634,569,694.03**	**649,186,786.66**	**0.00**	**8,283,756,480.69**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,634,569,694.03**	**649,186,786.66**	**0.00**	**8,283,756,480.69**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofNov 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 12-07-15 Run Time: 2:33:12 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	11,980,066.16	0.00	0.00	11,980,066.16	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	113,453,279.55	0.00	0.00	113,453,279.55	0.00
OtherAR Other	6,317,478.96	0.00	0.00	6,317,478.96	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	25.07	0.00	0.00	25.07	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	80,443,917.11	0.00	0.00	80,443,917.11	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	147,882,113.35	0.00	0.00	147,882,113.35	0.00
Prepayments	6,584,706.15	0.00	0.00	6,584,706.15	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	29,913,279.14	0.00	0.00	29,913,279.14	0.00
RegulatoryCurrentAssets Regulatory assets	18,773,381.45	0.00	0.00	18,773,381.45	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,134,963.10	199,627.09	0.00	2,334,590.19	0.00
Total current assets	417,483,210.04	199,627.09	0.00	417,682,837.13	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,551,471,595.07	(1,693,659,073.99)	0.00	6,857,812,521.08	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,440,643,714.97)	1,693,659,074.12	(0.00)	(746,984,640.85)	(0.00)
ConstructionWorkInProgress Construction work in progress	472,526,441.26	(0.13)	0.00	472,526,441.13	0.00
Property, plant and equipment, net	6,583,354,321.36	0.00	0.00	6,583,354,321.36	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	293,482,947.23	3,402,468.57	0.00	296,885,415.80	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,160,115.05	39,352,091.89	0.00	52,512,206.94	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	65,086,416.08	(3,383,994.17)	0.00	61,702,421.91	0.00
Total other noncurrent assets	371,729,478.36	646,774,934.52	0.00	1,018,504,412.88	0.00
Total Assets	7,372,567,009.76	646,974,561.61	0.00	8,019,541,571.37	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	0.00	0.00	0.00	0.00	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	97,803,619.39	0.00	0.00	97,803,619.39	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	45,806,127.41	0.00	0.00	45,806,127.41	0.00
TaxesAccrued Taxes	30,393,196.07	0.00	0.00	30,393,196.07	0.00
InterestAccrued Interest	9,207,369.61	0.00	0.00	9,207,369.61	0.00
DividendsPayable Dividends	47,000,000.00	0.00	0.00	47,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	18,986,729.26	199,627.09	0.00	19,186,356.35	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	26,152,692.53	0.00	0.00	26,152,692.53	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	54,405,869.96	0.00	0.00	54,405,869.96	0.00
Total current liabilities	329,755,604.23	199,627.09	0.00	329,955,231.32	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,341,084,854.05	382,532.67	0.00	2,341,467,386.72	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,341,084,854.05	382,532.67	0.00	2,341,467,386.72	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,047,850,752.25	(135,435.11)	0.00	1,047,715,317.14	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,172,789.57	0.00	0.00	93,172,789.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	44,592,769.04	0.00	0.00	44,592,769.04	0.00
AssetRetirementObligations Asset retirement obligations	341,762,380.75	0.00	0.00	341,762,380.75	0.00
RegulatoryLiabilities Regulatory liabilities	452,821,572.99	39,352,091.89	0.00	492,173,664.88	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	62,415,336.31	18,474.40	0.00	62,433,810.71	0.00
	2,042,615,600.91	39,235,131.18	0.00	2,081,850,732.09	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,789,037,809.60	(1,426,768,426.08)	0.00	362,269,383.52	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,603,630.72)	1,336,945.81	0.00	(266,684.91)	0.00
Total equity	2,659,110,950.57	607,157,270.67	0.00	3,266,268,221.24	0.00
Total liabilities and equity	**7,372,567,009.76**	**646,974,561.61**	**0.00**	**8,019,541,571.37**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,372,567,009.76**	**646,974,561.61**	**0.00**	**8,019,541,571.37**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,372,567,009.76**	**646,974,561.61**	**0.00**	**8,019,541,571.37**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofDec 2015
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 01-22-16 Run Time: 8:52:41 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	11,455,023.53	0.00	0.00	11,455,023.53	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	117,022,726.97	0.00	0.00	117,022,726.97	0.00
OtherAR Other	8,548,648.45	0.00	0.00	8,548,648.45	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	847,986.14	0.00	0.00	847,986.14	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	80,083,720.81	0.00	0.00	80,083,720.81	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	147,605,902.42	0.00	0.00	147,605,902.42	0.00
Prepayments	6,331,423.46	0.00	0.00	6,331,423.46	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	18,719,267.34	0.00	0.00	18,719,267.34	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	3,362,901.05	197,464.38	0.00	3,560,365.43	0.00
Total current assets	393,977,600.17	197,464.38	0.00	394,175,064.55	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,783,243,682.56	(1,683,778,294.84)	0.00	7,099,465,387.72	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,442,466,225.44)	1,683,778,294.97	(0.00)	(758,687,930.47)	(0.00)
ConstructionWorkInProgress Construction work in progress	267,026,967.55	(0.13)	0.00	267,026,967.42	0.00
Property, plant and equipment, net	6,607,804,424.67	0.00	0.00	6,607,804,424.67	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	299,378,054.66	3,366,757.72	0.00	302,744,812.38	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,131,146.08	37,160,503.88	0.00	50,291,649.96	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	48,242,572.34	0.00	0.00	48,242,572.34	0.00
Total other noncurrent assets	360,751,773.08	647,931,629.83	0.00	1,008,683,402.91	0.00
Total Assets	7,362,533,797.92	648,129,094.21	0.00	8,010,662,892.13	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	47,997,120.00	0.00	0.00	47,997,120.00	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	87,897,491.37	0.00	0.00	87,897,491.37	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	39,179,663.47	0.00	0.00	39,179,663.47	0.00
TaxesAccrued Taxes	20,494,120.49	0.00	0.00	20,494,120.49	0.00
InterestAccrued Interest	15,694,278.12	0.00	0.00	15,694,278.12	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	18,470,992.43	197,464.38	0.00	18,668,456.81	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayı	26,249,503.24	0.00	0.00	26,249,503.24	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	69,094,770.38	0.00	0.00	69,094,770.38	0.00
Total current liabilities	325,077,939.50	197,464.38	0.00	325,275,403.88	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,322,425,720.78	3,736,273.64	0.00	2,326,161,994.42	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,322,425,720.78	3,736,273.64	0.00	2,326,161,994.42	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,046,587,569.69	(143,741.61)	0.00	1,046,443,828.08	0.00
DeferredInvestmentTaxCredits Investment tax credits	93,018,937.57	0.00	0.00	93,018,937.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	46,318,894.88	0.00	0.00	46,318,894.88	0.00
AssetRetirementObligations Asset retirement obligations	335,399,785.71	0.00	0.00	335,399,785.71	0.00
RegulatoryLiabilities Regulatory liabilities	454,680,277.23	37,160,503.88	0.00	491,840,781.11	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	59,671,929.00	0.00	0.00	59,671,929.00	0.00
	2,035,677,394.08	37,016,762.27	0.00	2,072,694,156.35	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,809,303,187.19	(1,426,749,972.73)	0.00	382,553,214.46	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,627,215.32)	1,339,815.71	0.00	(287,399.61)	0.00
Total equity	2,679,352,743.56	607,178,593.92	0.00	3,286,531,337.48	0.00
Total liabilities and equity	**7,362,533,797.92**	**648,129,094.21**	**0.00**	**8,010,662,892.13**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,362,533,797.92**	**648,129,094.21**	**0.00**	**8,010,662,892.13**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,362,533,797.92**	**648,129,094.21**	**0.00**	**8,010,662,892.13**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofJan 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 02-05-16 Run Time: 11:14:27 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	10,299,331.57	0.00	0.00	10,299,331.57	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	135,283,825.94	0.00	0.00	135,283,825.94	0.00
OtherAR Other	5,081,552.38	0.00	0.00	5,081,552.38	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	451.67	0.00	0.00	451.67	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	100,938,266.76	0.00	0.00	100,938,266.76	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	146,511,525.83	0.00	0.00	146,511,525.83	0.00
Prepayments	7,693,526.17	0.00	0.00	7,693,526.17	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	17,067,153.37	0.00	0.00	17,067,153.37	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,349,324.68	195,327.00	0.00	1,544,651.68	0.00
Total current assets	424,224,958.37	195,327.00	0.00	424,420,285.37	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,809,659,154.14	(1,683,828,240.11)	0.00	7,125,830,914.03	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,463,386,875.29)	1,683,828,240.24	(0.00)	(779,558,635.05)	(0.00)
ConstructionWorkInProgress Construction work in progress	257,078,586.62	(0.13)	0.00	257,078,586.49	0.00
Property, plant and equipment, net	6,603,350,865.47	0.00	0.00	6,603,350,865.47	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	303,491,333.87	3,349,517.99	0.00	306,840,851.86	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,100,162.63	36,096,194.65	0.00	49,196,357.28	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	49,525,519.73	0.00	0.00	49,525,519.73	0.00
Total other noncurrent assets	366,117,016.23	646,850,080.87	0.00	1,012,967,097.10	0.00
Total Assets	7,393,692,840.07	647,045,407.87	0.00	8,040,738,247.94	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	43,220,464.71	0.00	0.00	43,220,464.71	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	77,442,886.45	0.00	0.00	77,442,886.45	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	40,348,015.62	0.00	0.00	40,348,015.62	0.00
TaxesAccrued Taxes	37,071,253.00	0.00	0.00	37,071,253.00	0.00
InterestAccrued Interest	22,945,602.99	0.00	0.00	22,945,602.99	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	14,867,035.34	195,327.00	0.00	15,062,362.34	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayı	26,502,955.47	0.00	0.00	26,502,955.47	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	66,250,083.24	0.00	0.00	66,250,083.24	0.00
Total current liabilities	328,648,296.82	195,327.00	0.00	328,843,623.82	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,322,576,190.71	3,706,017.15	0.00	2,326,282,207.86	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,322,576,190.71	3,706,017.15	0.00	2,326,282,207.86	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,046,587,569.72	(131,993.07)	0.00	1,046,455,576.65	0.00
DeferredInvestmentTaxCredits Investment tax credits	92,865,087.57	0.00	0.00	92,865,087.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	37,687,274.53	0.00	0.00	37,687,274.53	0.00
AssetRetirementObligations Asset retirement obligations	336,663,371.25	0.00	0.00	336,663,371.25	0.00
RegulatoryLiabilities Regulatory liabilities	455,160,642.01	36,096,194.65	0.00	491,256,836.66	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	60,228,955.79	0.00	0.00	60,228,955.79	0.00
	2,029,192,900.87	35,964,201.58	0.00	2,065,157,102.45	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,843,225,895.30	(1,426,731,519.37)	0.00	416,494,375.93	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,627,215.32)	1,322,630.57	0.00	(304,584.75)	0.00
Total equity	2,713,275,451.67	607,179,862.14	0.00	3,320,455,313.81	0.00
Total liabilities and equity	**7,393,692,840.07**	**647,045,407.87**	**0.00**	**8,040,738,247.94**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,393,692,840.07**	**647,045,407.87**	**0.00**	**8,040,738,247.94**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,393,692,840.07**	**647,045,407.87**	**0.00**	**8,040,738,247.94**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofFeb 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 03-07-16 Run Time: 10:45:12 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	11,947,098.24	0.00	0.00	11,947,098.24	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	148,906,514.03	0.00	0.00	148,906,514.03	0.00
OtherAR Other	3,648,015.26	0.00	0.00	3,648,015.26	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	25,565.99	0.00	0.00	25,565.99	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	96,023,012.01	0.00	0.00	96,023,012.01	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	153,344,147.07	0.00	0.00	153,344,147.07	0.00
Prepayments	6,654,052.11	0.00	0.00	6,654,052.11	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	9,678,339.48	0.00	0.00	9,678,339.48	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,828,263.94	193,189.62	0.00	2,021,453.56	0.00
Total current assets	432,055,008.13	193,189.62	0.00	432,248,197.75	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,826,108,883.03	(1,681,815,511.98)	0.00	7,144,293,371.05	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,480,593,515.86)	1,681,815,512.11	(0.00)	(798,778,003.75)	(0.00)
ConstructionWorkInProgress Construction work in progress	259,982,768.21	(0.13)	0.00	259,982,768.08	0.00
Property, plant and equipment, net	6,605,498,135.38	0.00	0.00	6,605,498,135.38	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	307,547,844.68	3,333,236.23	0.00	310,881,080.91	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,074,366.70	35,031,885.42	0.00	48,106,252.12	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	49,827,916.91	0.00	0.00	49,827,916.91	0.00
Total other noncurrent assets	370,450,128.29	645,769,489.88	0.00	1,016,219,618.17	0.00
Total Assets	7,408,003,271.80	645,962,679.50	0.00	8,053,965,951.30	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	15,999,182.22	0.00	0.00	15,999,182.22	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	76,478,328.37	0.00	0.00	76,478,328.37	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	39,150,288.77	0.00	0.00	39,150,288.77	0.00
TaxesAccrued Taxes	50,682,317.16	0.00	0.00	50,682,317.16	0.00
InterestAccrued Interest	30,274,053.85	0.00	0.00	30,274,053.85	0.00
DividendsPayable Dividends	64,000,000.00	0.00	0.00	64,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	17,449,427.94	193,189.62	0.00	17,642,617.56	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	27,098,711.83	0.00	0.00	27,098,711.83	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	58,941,719.72	0.00	0.00	58,941,719.72	0.00
Total current liabilities	380,074,029.86	193,189.62	0.00	380,267,219.48	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,322,718,481.26	3,677,558.43	0.00	2,326,396,039.69	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,322,718,481.26	3,677,558.43	0.00	2,326,396,039.69	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,046,587,569.72	(120,571.21)	0.00	1,046,466,998.51	0.00
DeferredInvestmentTaxCredits Investment tax credits	92,711,237.57	0.00	0.00	92,711,237.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	38,179,003.62	0.00	0.00	38,179,003.62	0.00
AssetRetirementObligations Asset retirement obligations	337,830,991.16	0.00	0.00	337,830,991.16	0.00
RegulatoryLiabilities Regulatory liabilities	454,492,805.32	35,031,885.42	0.00	489,524,690.74	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	60,416,039.04	0.00	0.00	60,416,039.04	0.00
	2,030,217,646.43	34,911,314.21	0.00	2,065,128,960.64	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,804,943,557.88	(1,426,713,579.13)	0.00	378,229,978.75	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,627,215.32)	1,305,445.43	0.00	(321,769.89)	0.00
Total equity	2,674,993,114.25	607,180,617.24	0.00	3,282,173,731.49	0.00
Total liabilities and equity	**7,408,003,271.80**	**645,962,679.50**	**0.00**	**8,053,965,951.30**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,408,003,271.80**	**645,962,679.50**	**0.00**	**8,053,965,951.30**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,408,003,271.80**	**645,962,679.50**	**0.00**	**8,053,965,951.30**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofMar 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 04-07-16 Run Time: 3:10:34 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	16,715,911.99	0.00	0.00	16,715,911.99	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	127,977,424.94	0.00	0.00	127,977,424.94	0.00
OtherAR Other	3,393,388.12	0.00	0.00	3,393,388.12	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	15,929.72	0.00	0.00	15,929.72	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	79,653,794.99	0.00	0.00	79,653,794.99	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	157,042,982.81	0.00	0.00	157,042,982.81	0.00
Prepayments	8,171,505.79	0.00	0.00	8,171,505.79	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	9,683,925.51	0.00	0.00	9,683,925.51	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,480,599.08	191,052.24	0.00	2,671,651.32	0.00
Total current assets	405,135,462.95	191,052.24	0.00	405,326,515.19	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,829,358,436.78	(1,681,703,926.69)	0.00	7,147,654,510.09	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pl	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,501,094,509.36)	1,681,703,926.82	(0.00)	(819,390,582.54)	(0.00)
ConstructionWorkInProgress Construction work in progress	285,732,467.46	(0.13)	0.00	285,732,467.33	0.00
Property, plant and equipment, net	6,613,996,394.88	0.00	0.00	6,613,996,394.88	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	310,879,532.85	3,316,146.94	0.00	314,195,679.79	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,048,570.77	33,967,576.19	0.00	47,016,146.96	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	50,312,899.09	0.00	0.00	50,312,899.09	0.00
Total other noncurrent assets	374,241,002.71	644,688,091.36	0.00	1,018,929,094.07	0.00
Total Assets	7,393,372,860.54	644,879,143.60	0.00	8,038,252,004.14	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	33,997,593.89	0.00	0.00	33,997,593.89	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	76,818,314.77	0.00	0.00	76,818,314.77	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	42,286,429.79	0.00	0.00	42,286,429.79	0.00
TaxesAccrued Taxes	12,107,442.37	0.00	0.00	12,107,442.37	0.00
InterestAccrued Interest	37,557,411.08	0.00	0.00	37,557,411.08	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	21,952,332.02	191,052.24	0.00	22,143,384.26	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	27,331,950.94	0.00	0.00	27,331,950.94	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
OtherCurrentLiabilities Other current liabilities	58,584,544.25	0.00	0.00	58,584,544.25	0.00
Total current liabilities	310,636,019.11	191,052.24	0.00	310,827,071.35	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,322,870,583.39	3,647,452.38	0.00	2,326,518,035.77	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,322,870,583.39	3,647,452.38	0.00	2,326,518,035.77	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,091,135,936.96	(128,877.76)	0.00	1,091,007,059.20	0.00
DeferredInvestmentTaxCredits Investment tax credits	92,557,387.57	0.00	0.00	92,557,387.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	37,481,818.98	0.00	0.00	37,481,818.98	0.00
AssetRetirementObligations Asset retirement obligations	334,105,016.87	0.00	0.00	334,105,016.87	0.00
RegulatoryLiabilities Regulatory liabilities	454,849,284.91	33,967,576.19	0.00	488,816,861.10	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	59,582,336.54	0.00	0.00	59,582,336.54	0.00
	2,069,711,781.83	33,838,698.43	0.00	2,103,550,480.26	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,820,248,627.04	(1,426,695,125.75)	0.00	393,553,501.29	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,770,922.52)	1,308,315.36	0.00	(462,607.16)	0.00
Total equity	2,690,154,476.21	607,201,940.55	0.00	3,297,356,416.76	0.00
Total liabilities and equity	**7,393,372,860.54**	**644,879,143.60**	**0.00**	**8,038,252,004.14**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,393,372,860.54**	**644,879,143.60**	**0.00**	**8,038,252,004.14**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,393,372,860.54**	**644,879,143.60**	**0.00**	**8,038,252,004.14**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

End

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofApr 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 05-06-16 Run Time: 12:36:13 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acct	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	16,008,359.17	0.00	0.00	16,008,359.17	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	114,552,987.53	0.00	0.00	114,552,987.53	0.00
OtherAR Other	8,180,429.88	0.00	0.00	8,180,429.88	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	724,626.00	0.00	0.00	724,626.00	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	76,364,703.84	0.00	0.00	76,364,703.84	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	158,630,943.17	0.00	0.00	158,630,943.17	0.00
Prepayments	11,877,372.31	0.00	0.00	11,877,372.31	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,393,811.62	0.00	0.00	12,393,811.62	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,148,302.18	188,914.86	0.00	1,337,217.04	0.00
Total current assets	399,881,535.70	188,914.86	0.00	400,070,450.56	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,842,130,647.82	(1,681,228,054.38)	0.00	7,160,902,593.44	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,519,033,659.79)	1,681,228,054.51	(0.00)	(837,805,605.28)	(0.00)
ConstructionWorkInProgress Construction work in progress	296,420,204.05	(0.13)	0.00	296,420,203.92	0.00
Property, plant and equipment, net	6,619,517,192.08	0.00	0.00	6,619,517,192.08	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	314,953,138.67	3,299,471.04	0.00	318,252,609.71	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	13,022,774.84	32,903,266.96	0.00	45,926,041.80	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	50,723,885.63	0.00	0.00	50,723,885.63	0.00
Total other noncurrent assets	378,699,799.14	643,607,106.23	0.00	1,022,306,905.37	0.00
Total Assets	7,398,098,526.92	643,796,021.09	0.00	8,041,894,548.01	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	21,341,253.03	0.00	0.00	21,341,253.03	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	73,937,831.13	0.00	0.00	73,937,831.13	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	44,461,776.95	0.00	0.00	44,461,776.95	0.00
TaxesAccrued Taxes	14,351,761.44	0.00	0.00	14,351,761.44	0.00
InterestAccrued Interest	35,104,804.16	0.00	0.00	35,104,804.16	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	21,891,955.42	188,914.86	0.00	22,080,870.28	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	27,528,309.63	0.00	0.00	27,528,309.63	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	29,489,797.00	0.00	0.00	29,489,797.00	0.00
OtherCurrentLiabilities Other current liabilities	33,905,778.51	0.00	0.00	33,905,778.51	0.00
Total current liabilities	302,013,267.27	188,914.86	0.00	302,202,182.13	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,323,017,770.10	3,618,179.62	0.00	2,326,635,949.72	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,323,017,770.10	3,618,179.62	0.00	2,326,635,949.72	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,091,135,936.96	(117,292.56)	0.00	1,091,018,644.40	0.00
DeferredInvestmentTaxCredits Investment tax credits	92,403,537.57	0.00	0.00	92,403,537.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	37,948,925.10	0.00	0.00	37,948,925.10	0.00
AssetRetirementObligations Asset retirement obligations	334,890,385.70	0.00	0.00	334,890,385.70	0.00
RegulatoryLiabilities Regulatory liabilities	454,382,428.08	32,903,266.96	0.00	487,285,695.04	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	60,167,523.51	0.00	0.00	60,167,523.51	0.00
	2,070,928,736.92	32,785,974.40	0.00	2,103,714,711.32	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,832,232,903.46	(1,426,676,928.95)	0.00	405,555,974.51	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,770,922.52)	1,291,130.22	0.00	(479,792.30)	0.00
Total equity	2,702,138,752.63	607,202,952.21	0.00	3,309,341,704.84	0.00
Total liabilities and equity	**7,398,098,526.92**	**643,796,021.09**	**0.00**	**8,041,894,548.01**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,398,098,526.92**	**643,796,021.09**	**0.00**	**8,041,894,548.01**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,398,098,526.92**	**643,796,021.09**	**0.00**	**8,041,894,548.01**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofMay 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 06-07-16 Run Time: 2:12:07 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acct	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	7,392,163.15	0.00	0.00	7,392,163.15	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	107,444,732.34	0.00	0.00	107,444,732.34	0.00
OtherAR Other	12,132,374.39	0.00	0.00	12,132,374.39	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	32.70	0.00	0.00	32.70	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	84,602,133.78	0.00	0.00	84,602,133.78	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	163,077,678.98	0.00	0.00	163,077,678.98	0.00
Prepayments	10,310,293.54	0.00	0.00	10,310,293.54	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,992,697.73	0.00	0.00	12,992,697.73	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,143,087.30	186,777.48	0.00	1,329,864.78	0.00
Total current assets	399,095,193.91	186,777.48	0.00	399,281,971.39	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,846,065,515.90	(1,679,759,994.88)	0.00	7,166,305,521.02	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,531,889,637.74)	1,679,759,995.01	(0.00)	(852,129,642.73)	(0.00)
ConstructionWorkInProgress Construction work in progress	310,378,718.79	(0.13)	0.00	310,378,718.66	0.00
Property, plant and equipment, net	6,624,554,596.95	0.00	0.00	6,624,554,596.95	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	319,033,810.48	3,282,220.71	0.00	322,316,031.19	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,996,978.91	31,838,957.73	0.00	44,835,936.64	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	51,327,807.66	0.00	0.00	51,327,807.66	0.00
Total other noncurrent assets	383,358,597.05	642,525,546.67	0.00	1,025,884,143.72	0.00
Total Assets	7,407,008,387.91	642,712,324.15	0.00	8,049,720,712.06	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	33,998,612.87	0.00	0.00	33,998,612.87	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	68,954,400.35	0.00	0.00	68,954,400.35	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	41,024,277.04	0.00	0.00	41,024,277.04	0.00
TaxesAccrued Taxes	14,423,333.34	0.00	0.00	14,423,333.34	0.00
InterestAccrued Interest	9,182,670.24	0.00	0.00	9,182,670.24	0.00
DividendsPayable Dividends	49,000,000.00	0.00	0.00	49,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	20,569,943.11	186,777.48	0.00	20,756,720.59	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	27,572,209.74	0.00	0.00	27,572,209.74	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	29,489,797.00	0.00	0.00	29,489,797.00	0.00
OtherCurrentLiabilities Other current liabilities	28,051,241.62	0.00	0.00	28,051,241.62	0.00
Total current liabilities	322,266,485.31	186,777.48	0.00	322,453,262.79	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,323,169,881.61	3,587,912.53	0.00	2,326,757,794.14	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,323,169,881.61	3,587,912.53	0.00	2,326,757,794.14	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,109,856,049.85	(118,914.05)	0.00	1,109,737,135.80	0.00
DeferredInvestmentTaxCredits Investment tax credits	92,249,687.57	0.00	0.00	92,249,687.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	38,463,654.77	0.00	0.00	38,463,654.77	0.00
AssetRetirementObligations Asset retirement obligations	335,512,141.20	0.00	0.00	335,512,141.20	0.00
RegulatoryLiabilities Regulatory liabilities	454,799,351.75	31,838,957.73	0.00	486,638,309.48	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	60,354,003.38	0.00	0.00	60,354,003.38	0.00
	2,091,234,888.52	31,720,043.68	0.00	2,122,954,932.20	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	563,858,083.00	2,032,588,750.94	0.00	2,596,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,800,437,637.70	(1,426,658,475.60)	0.00	373,779,162.10	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,777,276.92)	1,287,315.12	0.00	(489,961.80)	0.00
Total equity	2,670,337,132.47	607,217,590.46	0.00	3,277,554,722.93	0.00
Total liabilities and equity	**7,407,008,387.91**	**642,712,324.15**	**0.00**	**8,049,720,712.06**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,407,008,387.91**	**642,712,324.15**	**0.00**	**8,049,720,712.06**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,407,008,387.91**	**642,712,324.15**	**0.00**	**8,049,720,712.06**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofJun 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 07-08-16 Run Time: 2:33:32 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	19 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	7,690,255.71	0.00	0.00	7,690,255.71	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	113,209,899.64	0.00	0.00	113,209,899.64	0.00
OtherAR Other	4,265,065.59	0.00	0.00	4,265,065.59	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	1,862.99	0.00	0.00	1,862.99	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	93,327,915.96	0.00	0.00	93,327,915.96	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	156,951,338.03	0.00	0.00	156,951,338.03	0.00
Prepayments	15,544,869.68	0.00	0.00	15,544,869.68	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	13,481,359.17	0.00	0.00	13,481,359.17	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	669,938.00	184,640.10	0.00	854,578.10	0.00
Total current assets	405,142,504.77	184,640.10	0.00	405,327,144.87	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,881,814,815.40	(1,678,624,430.93)	0.00	7,203,190,384.47	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,545,465,929.28)	1,678,624,431.06	(0.00)	(866,841,498.22)	(0.00)
ConstructionWorkInProgress Construction work in progress	294,747,101.30	(0.13)	0.00	294,747,101.17	0.00
Property, plant and equipment, net	6,631,095,987.42	0.00	0.00	6,631,095,987.42	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	323,717,204.42	3,265,545.57	0.00	326,982,749.99	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,971,182.98	30,774,648.50	0.00	43,745,831.48	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	55,186,700.25	0.00	0.00	55,186,700.25	0.00
Total other noncurrent assets	391,875,087.65	641,444,562.30	0.00	1,033,319,649.95	0.00
Total Assets	7,428,113,579.84	641,629,202.40	0.00	8,069,742,782.24	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	28,997,472.22	0.00	0.00	28,997,472.22	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	72,894,371.26	0.00	0.00	72,894,371.26	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	52,696,233.21	0.00	0.00	52,696,233.21	0.00
TaxesAccrued Taxes	16,684,855.57	0.00	0.00	16,684,855.57	0.00
InterestAccrued Interest	15,627,585.43	0.00	0.00	15,627,585.43	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	17,109,976.20	184,640.10	0.00	17,294,616.30	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	27,610,573.63	0.00	0.00	27,610,573.63	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	38,874,478.00	0.00	0.00	38,874,478.00	0.00
OtherCurrentLiabilities Other current liabilities	31,610,057.20	0.00	0.00	31,610,057.20	0.00
Total current liabilities	302,105,602.72	184,640.10	0.00	302,290,242.82	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,323,317,067.57	3,558,640.54	0.00	2,326,875,708.11	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,323,317,067.57	3,558,640.54	0.00	2,326,875,708.11	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,119,895,496.28	(114,013.90)	0.00	1,119,781,482.38	0.00
DeferredInvestmentTaxCredits Investment tax credits	96,095,837.57	0.00	0.00	96,095,837.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	38,848,843.32	0.00	0.00	38,848,843.32	0.00
AssetRetirementObligations Asset retirement obligations	326,882,262.21	0.00	0.00	326,882,262.21	0.00
RegulatoryLiabilities Regulatory liabilities	458,117,380.80	30,774,648.50	0.00	488,892,029.30	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	46,922,016.58	0.00	0.00	46,922,016.58	0.00
	2,086,761,836.76	30,660,634.60	0.00	2,117,422,471.36	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	583,858,083.00	2,032,588,750.94	0.00	2,616,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,826,037,398.82	(1,426,640,278.78)	0.00	399,397,120.04	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,785,097.72)	1,276,815.00	0.00	(508,282.72)	0.00
Total equity	2,715,929,072.79	607,225,287.16	0.00	3,323,154,359.95	0.00
Total liabilities and equity	**7,428,113,579.84**	**641,629,202.40**	**0.00**	**8,069,742,782.24**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,428,113,579.84**	**641,629,202.40**	**0.00**	**8,069,742,782.24**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,428,113,579.84**	**641,629,202.40**	**0.00**	**8,069,742,782.24**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofJul 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 08-05-16 Run Time: 1:19:42 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	l9 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	10,748,141.04	0.00	0.00	10,748,141.04	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	137,664,954.23	0.00	0.00	137,664,954.23	0.00
OtherAR Other	5,075,491.07	0.00	0.00	5,075,491.07	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	2,818.53	0.00	0.00	2,818.53	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	101,827,016.24	0.00	0.00	101,827,016.24	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	153,955,646.69	0.00	0.00	153,955,646.69	0.00
Prepayments	17,108,268.65	0.00	0.00	17,108,268.65	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,968,783.40	0.00	0.00	12,968,783.40	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	953,059.41	182,502.72	0.00	1,135,562.13	0.00
Total current assets	440,304,179.26	182,502.72	0.00	440,486,681.98	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,903,394,048.21	(1,676,949,608.93)	0.00	7,226,444,439.28	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,559,009,608.32)	1,676,949,609.06	(0.00)	(882,059,999.26)	(0.00)
ConstructionWorkInProgress Construction work in progress	288,187,531.17	(0.13)	0.00	288,187,531.04	0.00
Property, plant and equipment, net	6,632,571,971.06	0.00	0.00	6,632,571,971.06	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	327,802,229.44	3,248,280.79	0.00	331,050,510.23	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,945,387.05	29,710,339.27	0.00	42,655,726.32	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	55,786,830.82	0.00	0.00	55,786,830.82	0.00
Total other noncurrent assets	396,534,447.31	640,362,988.29	0.00	1,036,897,435.60	0.00
Total Assets	7,469,410,597.63	640,545,491.01	0.00	8,109,956,088.64	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	21,999,586.67	0.00	0.00	21,999,586.67	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	76,800,370.03	0.00	0.00	76,800,370.03	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	40,543,387.71	0.00	0.00	40,543,387.71	0.00
TaxesAccrued Taxes	36,603,994.94	0.00	0.00	36,603,994.94	0.00
InterestAccrued Interest	22,872,743.17	0.00	0.00	22,872,743.17	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	16,087,431.09	182,502.72	0.00	16,269,933.81	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	27,771,029.84	0.00	0.00	27,771,029.84	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	38,874,478.00	0.00	0.00	38,874,478.00	0.00
OtherCurrentLiabilities Other current liabilities	29,262,133.97	0.00	0.00	29,262,133.97	0.00
Total current liabilities	310,815,155.42	182,502.72	0.00	310,997,658.14	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,323,469,193.53	3,528,358.99	0.00	2,326,997,552.52	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,323,469,193.53	3,528,358.99	0.00	2,326,997,552.52	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,119,895,496.28	(102,265.35)	0.00	1,119,793,230.93	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,941,987.57	0.00	0.00	95,941,987.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	39,888,198.87	0.00	0.00	39,888,198.87	0.00
AssetRetirementObligations Asset retirement obligations	329,583,053.73	0.00	0.00	329,583,053.73	0.00
RegulatoryLiabilities Regulatory liabilities	458,868,152.86	29,710,339.27	0.00	488,578,492.13	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	47,334,684.56	0.00	0.00	47,334,684.56	0.00
	2,091,511,573.87	29,608,073.92	0.00	2,121,119,647.79	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	583,858,083.00	2,032,588,750.94	0.00	2,616,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,853,723,000.84	(1,426,621,825.42)	0.00	427,101,175.42	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,785,097.72)	1,259,629.86	0.00	(525,467.86)	0.00
Total equity	2,743,614,674.81	607,226,555.38	0.00	3,350,841,230.19	0.00
Total liabilities and equity	**7,469,410,597.63**	**640,545,491.01**	**0.00**	**8,109,956,088.64**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,469,410,597.63**	**640,545,491.01**	**0.00**	**8,109,956,088.64**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,469,410,597.63**	**640,545,491.01**	**0.00**	**8,109,956,088.64**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofAug 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 09-09-16 Run Time: 12:45:10 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	l9 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	9,653,899.92	0.00	0.00	9,653,899.92	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	134,991,492.75	0.00	0.00	134,991,492.75	0.00
OtherAR Other	3,959,594.32	0.00	0.00	3,959,594.32	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	208,640.74	0.00	0.00	208,640.74	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	33,000,000.00	0.00	0.00	33,000,000.00	0.00
UnbilledRevenues Unbilled revenues	105,830,480.05	0.00	0.00	105,830,480.05	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	152,610,241.84	0.00	0.00	152,610,241.84	0.00
Prepayments	17,185,826.45	0.00	0.00	17,185,826.45	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,804,969.01	0.00	0.00	12,804,969.01	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,386,876.72	180,365.34	0.00	1,567,242.06	0.00
Total current assets	471,632,021.80	180,365.34	0.00	471,812,387.14	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,920,721,171.56	(1,675,049,299.24)	0.00	7,245,671,872.32	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,569,568,215.94)	1,675,049,299.37	(0.00)	(894,518,916.57)	(0.00)
ConstructionWorkInProgress Construction work in progress	282,962,925.43	(0.13)	0.00	282,962,925.30	0.00
Property, plant and equipment, net	6,634,115,881.05	0.00	0.00	6,634,115,881.05	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	333,058,584.62	2,045,120.18	0.00	335,103,704.80	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,919,591.12	28,646,030.04	0.00	41,565,621.16	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	54,878,053.12	0.00	0.00	54,878,053.12	0.00
Total other noncurrent assets	400,856,228.86	638,095,518.45	0.00	1,038,951,747.31	0.00
Total Assets	7,506,604,131.71	638,275,883.79	0.00	8,144,880,015.50	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	0.00	0.00	0.00	0.00	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	72,358,232.18	0.00	0.00	72,358,232.18	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	43,216,664.22	0.00	0.00	43,216,664.22	0.00
TaxesAccrued Taxes	59,382,341.43	0.00	0.00	59,382,341.43	0.00
InterestAccrued Interest	30,139,072.19	0.00	0.00	30,139,072.19	0.00
DividendsPayable Dividends	84,000,000.00	0.00	0.00	84,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	19,396,308.33	180,365.34	0.00	19,576,673.67	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	28,000,984.02	0.00	0.00	28,000,984.02	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	38,874,478.08	0.00	0.00	38,874,478.08	0.00
OtherCurrentLiabilities Other current liabilities	28,711,987.59	0.00	0.00	28,711,987.59	0.00
Total current liabilities	404,080,068.04	180,365.34	0.00	404,260,433.38	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,324,085,499.10	2,313,013.46	0.00	2,326,398,512.56	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,324,085,499.10	2,313,013.46	0.00	2,326,398,512.56	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,117,919,585.95	(90,840.39)	0.00	1,117,828,745.56	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,788,137.57	0.00	0.00	95,788,137.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	40,546,358.80	0.00	0.00	40,546,358.80	0.00
AssetRetirementObligations Asset retirement obligations	330,422,130.93	0.00	0.00	330,422,130.93	0.00
RegulatoryLiabilities Regulatory liabilities	458,804,751.38	28,646,030.04	0.00	487,450,781.42	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	46,482,009.55	0.00	0.00	46,482,009.55	0.00
	2,089,962,974.18	28,555,189.65	0.00	2,118,518,163.83	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	583,858,083.00	2,032,588,750.94	0.00	2,616,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,798,594,116.42	(1,426,603,880.32)	0.00	371,990,236.10	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,795,297.72)	1,242,444.72	0.00	(552,853.00)	0.00
Total equity	2,688,475,590.39	607,227,315.34	0.00	3,295,702,905.73	0.00
Total liabilities and equity	**7,506,604,131.71**	**638,275,883.79**	**0.00**	**8,144,880,015.50**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,506,604,131.71**	**638,275,883.79**	**0.00**	**8,144,880,015.50**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,506,604,131.71**	**638,275,883.79**	**0.00**	**8,144,880,015.50**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofSep 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 10-07-16 Run Time: 11:30:16 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	L9 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	7,092,000.12	0.00	0.00	7,092,000.12	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	140,549,582.46	0.00	0.00	140,549,582.46	0.00
OtherAR Other	3,480,182.68	0.00	0.00	3,480,182.68	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	620,839.43	0.00	0.00	620,839.43	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	0.00	0.00	0.00	0.00	0.00
UnbilledRevenues Unbilled revenues	84,077,076.16	0.00	0.00	84,077,076.16	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	151,387,702.20	0.00	0.00	151,387,702.20	0.00
Prepayments	15,758,596.42	0.00	0.00	15,758,596.42	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,132,319.82	0.00	0.00	12,132,319.82	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	1,461,201.90	178,227.96	0.00	1,639,429.86	0.00
Total current assets	416,559,501.19	178,227.96	0.00	416,737,729.15	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,944,094,721.86	(1,674,224,334.02)	0.00	7,269,870,387.84	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,587,254,706.79)	1,674,224,334.15	(0.00)	(913,030,372.64)	(0.00)
ConstructionWorkInProgress Construction work in progress	191,904,909.99	(0.13)	0.00	191,904,909.86	0.00
Property, plant and equipment, net	6,548,744,925.06	0.00	0.00	6,548,744,925.06	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	334,766,380.64	2,034,406.01	0.00	336,800,786.65	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,893,795.19	27,581,720.81	0.00	40,475,516.00	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	55,465,217.39	0.00	0.00	55,465,217.39	0.00
Total other noncurrent assets	403,125,393.22	637,020,495.05	0.00	1,040,145,888.27	0.00
Total Assets	7,368,429,819.47	637,198,723.01	0.00	8,005,628,542.48	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	6,999,556.67	0.00	0.00	6,999,556.67	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	66,663,987.82	0.00	0.00	66,663,987.82	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	41,596,348.87	0.00	0.00	41,596,348.87	0.00
TaxesAccrued Taxes	23,466,579.74	0.00	0.00	23,466,579.74	0.00
InterestAccrued Interest	37,528,033.68	0.00	0.00	37,528,033.68	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	19,299,584.92	178,227.96	0.00	19,477,812.88	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	28,315,862.36	0.00	0.00	28,315,862.36	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	15,365,119.55	0.00	0.00	15,365,119.55	0.00
OtherCurrentLiabilities Other current liabilities	33,880,332.58	0.00	0.00	33,880,332.58	0.00
Total current liabilities	273,115,406.19	178,227.96	0.00	273,293,634.15	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,324,234,010.00	2,289,702.43	0.00	2,326,523,712.43	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,324,234,010.00	2,289,702.43	0.00	2,326,523,712.43	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,165,783,258.87	(99,310.26)	0.00	1,165,683,948.61	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,634,287.57	0.00	0.00	95,634,287.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	33,540,459.16	0.00	0.00	33,540,459.16	0.00
AssetRetirementObligations Asset retirement obligations	260,852,274.19	0.00	0.00	260,852,274.19	0.00
RegulatoryLiabilities Regulatory liabilities	459,172,983.06	27,581,720.81	0.00	486,754,703.87	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	46,187,675.07	0.00	0.00	46,187,675.07	0.00
	2,061,170,937.92	27,482,410.55	0.00	2,088,653,348.47	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	583,858,083.00	2,032,588,750.94	0.00	2,616,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,820,031,844.39	(1,426,585,683.49)	0.00	393,446,160.90	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,799,150.72)	1,245,314.62	0.00	(553,836.10)	0.00
Total equity	2,709,909,465.36	607,248,382.07	0.00	3,317,157,847.43	0.00
Total liabilities and equity	**7,368,429,819.47**	**637,198,723.01**	**0.00**	**8,005,628,542.48**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,368,429,819.47**	**637,198,723.01**	**0.00**	**8,005,628,542.48**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,368,429,819.47**	**637,198,723.01**	**0.00**	**8,005,628,542.48**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofOct 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 11-07-16 Run Time: 2:43:45 PM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	l9 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	10,282,518.34	0.00	0.00	10,282,518.34	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	116,559,782.48	0.00	0.00	116,559,782.48	0.00
OtherAR Other	4,845,081.76	0.00	0.00	4,845,081.76	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	0.00	0.00	0.00	0.00	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	37,600,000.00	0.00	0.00	37,600,000.00	0.00
UnbilledRevenues Unbilled revenues	77,436,291.05	0.00	0.00	77,436,291.05	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	144,797,135.89	0.00	0.00	144,797,135.89	0.00
Prepayments	13,796,970.27	0.00	0.00	13,796,970.27	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,003,790.28	0.00	0.00	12,003,790.28	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,013,003.47	176,090.58	0.00	2,189,094.05	0.00
Total current assets	419,334,573.54	176,090.58	0.00	419,510,664.12	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,955,404,473.07	(1,673,518,186.80)	0.00	7,281,886,286.27	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,603,384,447.38)	1,673,518,186.93	(0.00)	(929,866,260.45)	(0.00)
ConstructionWorkInProgress Construction work in progress	204,257,343.21	(0.13)	0.00	204,257,343.08	0.00
Property, plant and equipment, net	6,556,277,368.90	0.00	0.00	6,556,277,368.90	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	336,676,296.32	2,023,341.80	0.00	338,699,638.12	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,968,803.30	26,517,411.58	0.00	39,486,214.88	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	56,271,193.44	0.00	0.00	56,271,193.44	0.00
Total other noncurrent assets	405,916,293.06	635,945,121.61	0.00	1,041,861,414.67	0.00
Total Assets	7,381,528,235.50	636,121,212.19	0.00	8,017,649,447.69	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	0.00	0.00	0.00	0.00	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	72,209,255.31	0.00	0.00	72,209,255.31	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	41,199,689.05	0.00	0.00	41,199,689.05	0.00
TaxesAccrued Taxes	21,972,593.94	0.00	0.00	21,972,593.94	0.00
InterestAccrued Interest	35,285,275.28	0.00	0.00	35,285,275.28	0.00
DividendsPayable Dividends	0.00	0.00	0.00	0.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	16,550,435.47	176,090.58	0.00	16,726,526.05	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	28,417,765.40	0.00	0.00	28,417,765.40	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	15,365,119.55	0.00	0.00	15,365,119.55	0.00
OtherCurrentLiabilities Other current liabilities	40,139,309.55	0.00	0.00	40,139,309.55	0.00
Total current liabilities	271,139,443.55	176,090.58	0.00	271,315,534.13	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,324,275,164.01	2,265,621.46	0.00	2,326,540,785.47	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,324,275,164.01	2,265,621.46	0.00	2,326,540,785.47	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,165,783,258.87	(87,561.72)	0.00	1,165,695,697.15	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,480,437.57	0.00	0.00	95,480,437.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	34,853,169.37	0.00	0.00	34,853,169.37	0.00
AssetRetirementObligations Asset retirement obligations	259,968,689.84	0.00	0.00	259,968,689.84	0.00
RegulatoryLiabilities Regulatory liabilities	459,167,373.09	26,517,411.58	0.00	485,684,784.67	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	46,568,098.84	0.00	0.00	46,568,098.84	0.00
	2,061,821,027.58	26,429,849.86	0.00	2,088,250,877.44	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	583,858,083.00	2,032,588,750.94	0.00	2,616,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,834,414,979.39	(1,426,567,230.13)	0.00	407,847,749.26	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,799,150.72)	1,228,129.48	0.00	(571,021.24)	0.00
Total equity	2,724,292,600.36	607,249,650.29	0.00	3,331,542,250.65	0.00
Total liabilities and equity	**7,381,528,235.50**	**636,121,212.19**	**0.00**	**8,017,649,447.69**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,381,528,235.50**	**636,121,212.19**	**0.00**	**8,017,649,447.69**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,381,528,235.50**	**636,121,212.19**	**0.00**	**8,017,649,447.69**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Company Consolidated
CONSOLIDATING BALANCE SHEET - Selectable Data Types
As ofNov 2016
Entity: L0800_Consol.L0110_Consol
Report ID: Consolidating Balance Sheet
Run Date: 12-07-16 Run Time: 10:57:14 AM

Scenario: Actual View: YTD ICP: [ICP Top] Custom2: [None] Custom3: [None] Custom4: [None]

	L0110 Kentucky Utilities Company	L9 Kentucky Utilities Company Purchase Acctg	Eliminations	0_Consol Kentucky Utilities Company Consolidated	BU Check
Current assets:					
CashCashEquivalents Cash and cash equivalents	23,527,373.03	0.00	0.00	23,527,373.03	0.00
ShortTermInvestments Short-term investments	0.00	0.00	0.00	0.00	0.00
Customer	109,881,333.66	0.00	0.00	109,881,333.66	0.00
OtherAR Other	5,788,675.33	0.00	0.00	5,788,675.33	0.00
AccountsReceivableFromAffiliates Accounts receivable from affi	3,102.85	0.00	0.00	3,102.85	0.00
NotesReceivableFromAffiliatedCo Notes receivable from affiliate	3,800,000.00	0.00	0.00	3,800,000.00	0.00
UnbilledRevenues Unbilled revenues	84,825,944.62	0.00	0.00	84,825,944.62	0.00
FuelMaterialSuppliesAverageCost Fuel, materials, and supplies	148,961,710.91	0.00	0.00	148,961,710.91	0.00
Prepayments	12,193,457.13	0.00	0.00	12,193,457.13	0.00
InterestRatePRMACur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMACur Affiliated	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentAssets Deferred income taxes	0.00	0.00	0.00	0.00	0.00
RegulatoryCurrentAssets Regulatory assets	12,746,853.07	0.00	0.00	12,746,853.07	0.00
RestrictedCash Restricted cash and cash equivalents	0.00	0.00	0.00	0.00	0.00
OtherCurrentAssets Other current assets	2,381,542.88	173,953.20	0.00	2,555,496.08	0.00
Total current assets	404,109,993.48	173,953.20	0.00	404,283,946.68	0.00
EquityMethodInvestments Equity method investments	0.00	0.00	0.00	0.00	0.00
Property, plant and equipment:					
RegulatedUtilityPlantElectricGas Regulated utility plant	8,991,283,909.54	(1,672,857,061.27)	0.00	7,318,426,848.27	0.00
NonregulatedPropertyPlantEquipNet Non-regulated property, pla	0.00	0.00	0.00	0.00	0.00
LessAccumDepRegUtilityPlant Less accumulated depreciation -	(2,620,896,497.35)	1,672,857,061.40	(0.00)	(948,039,435.95)	(0.00)
ConstructionWorkInProgress Construction work in progress	205,991,509.09	(0.13)	0.00	205,991,508.96	0.00
Property, plant and equipment, net	6,576,378,921.28	0.00	0.00	6,576,378,921.28	0.00
Other noncurrent assets:					
RegulatoryNoncurrentAssets Regulatory assets	340,386,307.50	2,012,619.46	0.00	342,398,926.96	0.00
Goodwill	0.00	607,404,368.23	0.00	607,404,368.23	0.00
OtherIntangiblesNoncurrent Other intangibles	12,942,926.69	25,453,102.35	0.00	38,396,029.04	0.00
CostMethodInvestments Cost method investments	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMANoncur Affiliated	0.00	0.00	0.00	0.00	0.00
OtherInvestments Other Investments	0.00	0.00	0.00	0.00	0.00
OtherNoncurrentAssets Other noncurrent assets	56,958,888.26	0.00	0.00	56,958,888.26	0.00
Total other noncurrent assets	410,288,122.45	634,870,090.04	0.00	1,045,158,212.49	0.00
Total Assets	7,390,777,037.21	635,044,043.24	0.00	8,025,821,080.45	0.00
Current liabilities:					
ShortTermDebtExternal Short-term debt external	0.00	0.00	0.00	0.00	0.00
ShortTermDebtAffiliates Short-term debt with affiliates	0.00	0.00	0.00	0.00	0.00
LongTermDebtDueWithinOneYr Long-term debt due within one y	0.00	0.00	0.00	0.00	0.00
AccountsPayable Accounts payable	79,750,063.02	0.00	0.00	79,750,063.02	0.00
AccountsPayableToAffiliates Accounts payable to affiliates	35,483,964.50	0.00	0.00	35,483,964.50	0.00
TaxesAccrued Taxes	34,093,454.97	0.00	0.00	34,093,454.97	0.00
InterestAccrued Interest	9,456,757.18	0.00	0.00	9,456,757.18	0.00
DividendsPayable Dividends	51,000,000.00	0.00	0.00	51,000,000.00	0.00
InterestRatePRMLCur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLCur Affiliated	0.00	0.00	0.00	0.00	0.00
RegulatoryLiabilitiesCurrent Regulatory liabilities	15,683,683.67	173,953.20	0.00	15,857,636.87	0.00
CounterpartyCollateral Counterparty collateral	0.00	0.00	0.00	0.00	0.00
CustomerDepositsPrepayments Customer deposits and prepayr	28,643,972.31	0.00	0.00	28,643,972.31	0.00
Vacation	0.00	0.00	0.00	0.00	0.00
DeferredIncomeTaxesCurrentLiab Deferred income taxes	0.00	0.00	0.00	0.00	0.00
AssetRetirementObligationCur Asset retirement obligation	15,365,119.55	0.00	0.00	15,365,119.55	0.00
OtherCurrentLiabilities Other current liabilities	32,671,115.39	0.00	0.00	32,671,115.39	0.00
Total current liabilities	302,148,130.59	173,953.20	0.00	302,322,083.79	0.00
Long-term debt:					
LongTermDebtDt Long-term debt	2,324,430,883.84	2,242,302.26	0.00	2,326,673,186.10	0.00
NotesPayableToAffiliates Notes payable to affiliates	0.00	0.00	0.00	0.00	0.00
Total long-term debt	2,324,430,883.84	2,242,302.26	0.00	2,326,673,186.10	0.00
Deferred credits and other noncurrent liabilities:					
DeferredIncomeTaxesNoncurrent Deferred income taxes	1,165,787,226.67	(75,976.49)	0.00	1,165,711,250.18	0.00
DeferredInvestmentTaxCredits Investment tax credits	95,326,587.57	0.00	0.00	95,326,587.57	0.00
InterestRatePRMLNoncur Interest-rate	0.00	0.00	0.00	0.00	0.00
AffiliatedPRMLNoncur Affiliated	0.00	0.00	0.00	0.00	0.00
AccruedPensionObligations Accrued pension obligations	35,132,866.34	0.00	0.00	35,132,866.34	0.00
AssetRetirementObligations Asset retirement obligations	272,543,151.67	0.00	0.00	272,543,151.67	0.00
RegulatoryLiabilities Regulatory liabilities	460,132,147.12	25,453,102.35	0.00	485,585,249.47	0.00
OtherNoncurrentLiabilities Other deferred credits and noncurren	46,578,752.03	0.00	0.00	46,578,752.03	0.00
	2,075,500,731.40	25,377,125.86	0.00	2,100,877,857.26	0.00
Equity:					
CommonStock Common stock	307,818,688.69	0.00	0.00	307,818,688.69	0.00
AdditionalPaidInCapital Additional paid-in capital	583,858,083.00	2,032,588,750.94	0.00	2,616,446,833.94	0.00
SEC_EarningsReinvested Earnings reinvested	1,798,829,870.41	(1,426,549,033.36)	0.00	372,280,837.05	0.00
AccumulatedOtherComprehensiveIncome Accumulated other cc	(1,809,350.72)	1,210,944.34	0.00	(598,406.38)	0.00
Total equity	2,688,697,291.38	607,250,661.92	0.00	3,295,947,953.30	0.00
Total liabilities and equity	**7,390,777,037.21**	**635,044,043.24**	**0.00**	**8,025,821,080.45**	**0.00**
Balance sheet balance (S/B zero)?	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
From HFM:					
SEC_Assets Assets	**7,390,777,037.21**	**635,044,043.24**	**0.00**	**8,025,821,080.45**	**0.00**
SEC_LiabilitiesStockholderEquity Liabilities and Stockholders' E	**7,390,777,037.21**	**635,044,043.24**	**0.00**	**8,025,821,080.45**	**0.00**
Differences (S/B zero):					
Total assets	0.00	0.00	0.00	0.00	0.00
Total liabilities and equity	0.00	0.00	0.00	0.00	0.00

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 36

Responding Witness: John P. Malloy

Q-36. Refer to the Staffieri Testimony, page 8.

a. Provide both a description of Site Selection magazine and the September 2016 article recognizing the Companies as top utilities for support of economic growth.

b. Describe in detail the $2.7 billion in corporate projects and the 9,400 jobs for which the Companies' economic development team was honored.

A.36.

a. For a description of Site Selection magazine, see Malloy Testimony, Page 4, lines 12-19. For a copy of the 2016 article recognizing LG&E and KU as a top utility for support of economic growth, see attached.

b. In June 2016, information queried from the Kentucky Cabinet for Economic Development (KCED) and submitted to Site Selection magazine represented the number of announced investment ($2.7 billion) and jobs (9,400) within the counties the Companies serve. An updated query of this information as of January 2017 from the KCED reflects an announced investment of $3.2 billion and 11,899 jobs within the counties the Companies serve.

These 346 announced company locations or expansions are located throughout Kentucky in 56 different counties (82 cities). This diverse mix of announced company locations and expansions represent the growing bourbon/distilled spirits industry, automotive and automotive suppliers, diverse group of manufacturers, logistics/distribution/warehouse, and many other unique industries. Specifically the KCED breaks down these 2015 announced company locations expansions accordingly:

- 6,822 manufacturing expansions,
- 1,259 manufacturing locations,
- 685 service locations, and
- 3,133 service expansions.

TOP UTILITIES OF 2016

From Site Selection magazine, September 2016

The Year's Best Utilities Give You Much More Than Power

Service, data, technology and savvy add up to success for these top-performing teams in economic development.

TVA pretty much invented utility economic development. Here workers are shown in the 1930s constructing the Norris Dam, TVA's first hydroelectric project, where the agency this summer commemorated the dam's 80th anniversary of operations.

Photos courtesy of TVA

by ADAM BRUNS

Ask any sales pro: If you know your customer as well as you know your territory, you're halfway home.

In the case of serving the utility needs of existing, expanding and new companies — as well as serving the communities in which they operate — getting to know customers' needs and challenges is helping them grow. It can mean making a lot more connections than the electrical kind. And ultimately, it helps those companies feel right at home.

Each year since 1999, Site Selection evaluates the performance of utility economic development teams based on corporate facility project jobs and capex figures from the previous calendar year in the utilities' service areas. Metrics include both straight totals and per-capita calculations, as well as website tools and data; innovative programs and incentives for business; and the utility's own job-creating infrastructure and facility investment trends.

Here, in alphabetical order, we present this year's Top Utilities and Honorable Mentions.

Alabama Power

Birmingham, Alabama

www.amazingalabama.com

Serving the southern two-thirds of Alabama, this Southern Company utility helped deliver $2.43 billion in corporate facility investment in its territory last year, which will help create 2,325 jobs among the region's population of 1.4 million. "In 2015, we put emphasis on developing new initiatives in Economic Development, Marketing, Supply Chain, and other areas of the company to better understand the factors driving our customers' success as well as identifying new ways to create opportunities for them," writes Patrick Murphy, economic & community development vice president.

That includes target sector strategies for aerospace (Airbus just produced its first aircraft in Mobile), automotive (Magna and Mercedes expansions in 2015), chemicals and data centers. As part of marketing alliance the Alabama Allies, the Alabama Power team attended AAMA Southern Automotive, Center for Automotive Research, Hamburg Aviation, Informex, SelectUSA and other targeted industry forums in 2015. In September 2015, Alabama Power received regulatory approval to construct up to 500 MW of renewable energy generation in the state over the next six years: The first two projects are large military solar projects at the Anniston Army Depot and Fort Rucker.

American Electric Power

Columbus, Ohio

www.aeped.com

The AEP Economic & Business Development team (AEPED) helped draw more than $8.1 billion in corporate facility investment in its 11-state territory in 2015, from companies aiming to create no less than 9,613 jobs.

In addition to the utility's network of power plants, the 200,000-sq.-mile (518,000-sq.-km.) territory of AEP is now served by an updated Web portal, unveiled in July 2016. "From a blog to infographics, maps and presentations, the site provides information and interactive tools designed to serve corporations who may be interested in AEP's 74,000 industrial-ready acres of available property, 3,000 communities served or access to the fastest growing shale plays in the US," said a release.

Among the tools are portfolios of sites specially prepared to welcome industrial users (certified in partnership with McCallum Sweeney), data centers (Biggins Lacy Shapiro & Co.) and food processing operations (Austin Consulting).

CenterPoint Energy

Houston, Texas

www.centerpointenergy.com/ecodev

Economic Development Manager John Cook and his team at CenterPoint helped facilitate $3.6 billion of corporate facility investment in Greater Houston, expected to create 15,400 jobs. That couldn't be more welcome news in a region suffering from the drop in energy prices. Cook highlights the Daikin/Goodman decision to locate its headquarters/manufacturing campus in the Houston area, "which is under construction as we speak." He salutes area economic development entities, cities, counties and the Governor's Office of Economic Development in helping the company evaluate a consolidation, repeating a process first considered in 2008 and then revisited after Daikin acquired the firm in 2014.

"This team approach is how projects are usually won, and this was a big win," writes Cook. "Not only did Daikin consolidate all operations in the US to one location in the Houston area, they will be manufacturing products here that have never been produced in this country before. "The net new direct jobs to this region was over 2,000, and if we had lost this project to a competing location the direct and indirect job losses would have been over 11,000."

Duke Energy

Charlotte, North Carolina

locationdukeenergy.com

More than $3.5 billion in corporate investment that will help create 12,043 jobs was the quarry mined by Duke's economic development team in 2015 across its six-state territory, where some 7.4 million customers are served amid a population of 24 million people. Enhancing the three primary pillars of site readiness, industrial recruitment and economic development was central to success, writes Stuart Heishman, vice president economic development, business recruitment & territorial strategies for Duke Energy. Site readiness efforts were tailored to the needs of each state, with more new options for site enhancement offered, he says. The team also deployed a new model for business recruitment, with staff operating out of key target markets including San Francisco, Detroit, Atlanta, Orlando and Raleigh.

"Finally, our economic development managers in each jurisdiction assumed a leadership role in the enhancement of numerous megasites throughout our service territory," he says. "This included the Liberty and Siler City megasites in North Carolina, the Newberry megasite in South Carolina, Mt. Orab in Ohio and River Ridge in Indiana."

ElectriCities of North Carolina

Raleigh, North Carolina

www.electricities.com

More than $1.5 billion in investment aiming to create 5,316 jobs spelled success in ElectriCities territory. ElectriCities is a membership organization including public power communities in North Carolina, South Carolina and Virginia. It also provides management services to the state's two municipal power agencies: North Carolina Municipal Power Agency Number 1 and North Carolina Eastern Municipal Power Agency. Among its community services are marketing assistance, client proposals, trade show opportunities and even aerial photography.

Shovel-ready sites at Tarboro Commerce Center, Statesville Business Park and Wilson Corporate Park were named in September 2015 as the inaugural class in the utility's new Smart Sites program. Meanwhile, since the team brought Atlanta-based Global Consulting board in 2012 to field inquiries from European prospects, more than 70 European-based direct investment prospects have come on the radar. "In fact, one British company is currently setting up a manufacturing facility in the Piedmont," said ElectriCities in a newsletter this past spring, "and three other companies are expected to announce new facilities in the next 12 to 18 months."

Entergy

New Orleans, Louisiana

entergysiteselection.com

Entergy directly supported the establishment in 2015 of projects that will result in nearly $10.3 billion of capital investment and the creation of more than 4,835 new jobs in the utility's four-state region. These include 100 from Shintech's $1.4-billion investment in Louisiana, 225 from Ozark Mountain Poultry's project in Arkansas and many others. Entergy continues to dramatically step up its economic development efforts with the formation and growth of a Corporate Business and Economic Development Department that augments and supports the economic development teams in each of the four states Entergy serves.

“The attraction, retention, and expansion of commercial and industrial customers is a very competitive process, not just in the Gulf South but domestically and globally,” says Paula Waters, Entergy's vice president of utility sales and development services. “Utilities like Entergy must be actively involved in the economic development process by working closely with the various state agencies and local communities to create a positive outcome as well as taking proactive steps to help uncover new opportunities for the communities we serve. Entergy is consistently looking to secure new load growth and recently helped drive $90 million in new sales in our service territory. Pivotal to the continued success, working alongside our customers and state and local partners, is our understanding of the region's highly competitive utility rates, superior infrastructure, constructive business climate, and able workforce that will lead to the sustainability and growth of the overall economic expansion in our region.”

Georgia Power

Atlanta, Georgia

selectgeorgia.com

One hundred and two projects worth $3.68 billion and creating 13,456 jobs boosted this Southern Company flagship once again to the upper echelon. The long list of 2015 projects included the headline news of Mercedes-Benz USA moving its HQ to the Atlanta suburb of Sandy Springs from New Jersey; Tyson Foods' $110-million, 500-job expansion in Vienna; Aspen Aerogels' $70-million, 106-job project in Statesboro; and ADP's $20-million, 450-job expansion in Augusta.

Initiatives implemented during 2015 included enhanced 3D animation; advanced storymaps (including their use in a publication called “Exploring Atlanta as a Millennial”); acquisition of the new CareerBuilder workforce information tool; formation of a creative services team; SAM, the

Site Analysis Matrix; and a pilot partnership with the University of North Georgia that will enable the university to justify investing in new curriculum offerings — a program likely to be replicated with other Georgia schools soon.

LG&E-Kentucky Utilities (PPL)

Louisville, Kentucky

site-selection.com

This utility's three brands are Louisville Gas & Electric, Kentucky Utilities and Old Dominion Power, which serve 16 Kentucky counties, 77 Kentucky counties and five Virginia counties, respectively. The collective economic development team in 2015 helped bring to fruition corporate projects worth $2.7 billion, creating 9,416 jobs.

Event marketing included missions to Chicago, Dallas, Detroit, New York, Cincinnati, Atlanta and consultant events in Richmond and Hopkinsville, Kentucky. LG&E and KU continued a long-term investment strategy to support the development of industrial land in two Kentucky communities. The zero-interest loans allowed one community to complete its first land sale in 20 years. The team is increasingly called upon as a resource to design and implement new programs and strategies, including working closely with the Kentucky Workforce Investment Board as it nurtured the Work Ready Community program.

In April, utility officials and political leaders unveiled the state's largest solar facility at E.W. Brown Generating Station in Mercer County. "We're embarking on a new era and introducing a new source of energy to our generation portfolio that will work in concert with our coal, natural gas and hydroelectric fleet." said Paul W. Thompson, COO for LG&E and KU.

PECO, An Exelon Company

Philadelphia, Pennsylvania

www.peco.com/economic

As the region's electric and natural gas utility, PECO works directly with the Pennsylvania Governor's Action Team, Select Greater Philadelphia and each of the five county economic development corporations in its service territory. In 2015, that work resulted in corporate end-user projects worth $7 billion, creating 8,000 jobs.

“Stakeholder outreach is key to our economic development program, but we also work internally with our large account managers, capacity planning, rates and regulatory departments and energy efficiency team,” writes Maureen Sharkey, senior economic development specialist. “We recently instituted a Rapid Response Growth Team within PECO to salute large prospects, address questions and customize assistance during the site selection process.”

Two of the biggest projects on the dance card are the $2.5-billion Sunoco Logistics Mariner East Pipeline, which along with anticipated growth in the Marcus Hook Industrial Complex area resulted in the construction of a new PECO substation; and the $1.2-billion Comcast Innovation and Technology Center, expected to create 3,000 jobs over time.

Long-term projects PECO is integrally involved with include UCitySquare, a development project that will grow the city’s University Science Center six-fold by the time the 10-year, $1-billion plan is completed; and the $3.5-billion, 20-year plan for Schuylkill Yards, a next-generation innovation community created through a partnership between Drexel University and Brandywine Realty Trust.

Tennessee Valley Authority

Nashville, Tennessee

TVAsites.com

Cumulative investment of $7.8 billion from 224 companies, expected to create 76,200 jobs across the seven states and 80,000 sq. miles (207,200 sq. km.) of TVA territory — not a bad year’s work for TVA Economic Development. Topping the list in story value was Google’s decision to invest $600 million in a 75-job data center at the site of a retiring TVA coal-fired power plant.

In celebrating receiving Site Selection’s Top Utilities award in 2015 for the 10th consecutive year, says senior TVA ED consultant Haley Sorrells, “ ‘The Power of 10’ became the group’s theme throughout 2015, celebrating a decade of service. We take great pride in being cited for economic excellence by Site Selection Magazine, and want the quality of the work we do to yield excellence in living for the people in our service territory for decades to come.”

In 2015, in order to better prepare communities, the team ramped up promotion to consultants of its InvestPrep™ program, a product development readiness initiative to help communities market industrial sites and buildings. New in 2015, Rural Development staff created an economic development training course for elected officials. TVA Community Development also entered its third year with the Valley Sustainable Communities Program, which now counts 28 communities in its fold.

"Economic development is in our DNA, and has been right from the start," said TVA President and CEO Bill Johnson in April. "Some might say that everything TVA does funnels down to strengthening the economy of our region."

2016 HONORABLE MENTION UTILITIES IN ECONOMIC DEVELOPMENT

Ameren Corp., St. Louis, Missouri, www.ameren.com/ecdev

ComEd (Exelon), Oakbrook Terrace, Illinois, www.comed.com/econdev

First Energy, Akron, Ohio, firstenergycorp.com/ed

Florida Power & Light Co., Juno Beach, Florida, www.PoweringFlorida.com

Gulf Power Company, Pensacola, Florida, www.GulfPower.com/Grow

Kansas City Power & Light, Kansas City, Missouri, www.kcpled.com

Mississippi Power, Gulfport, Mississippi, economicdevelopment.mississippipower.com

Omaha Public Power District, Omaha, Nebraska, www.oppd.com

PowerSouth Energy, Montgomery, Alabama, www.powersouth.com

South Carolina Power Team, Columbia, South Carolina, scpowerteam.com

Tucson Electric Power, Tucson, Arizona, www.tep.com

The Future Is Here

Xcel Energy in July 2016 celebrated the opening of its new headquarters in downtown Minneapolis, Minnesota, right across the street from its former digs. In the fall of 1965 Xcel Energy's predecessor, Northern States Power, installed a time capsule after completing its then-new HQ across the street. Last fall, Xcel employees opened it, finding containers of coal representing the amount of coal needed to generate a kilowatt-hour of electricity in 1915 and 1965; and a letter from two young students about what it was like to be a teenager in 1965. A new capsule at the new HQ contains a 3-D-printed wind turbine, Twin Cities newspapers, a copy of the Clean Energy Partnership agreement, and ... sigh ... a selfie stick.

Adam Bruns
Managing Editor of Site Selection magazine

Adam Bruns has served as managing editor of Site Selection magazine since February 2002. In the course of reporting hundreds of stories for Site Selection, Adam has visited companies and communities around the globe. A St. Louis native who grew up in the Kansas City suburbs, Adam is a 1986 alumnus of Knox College, and resided in Chicago; Midcoast Maine; Savannah, Georgia; and Lexington, Kentucky, before settling in the Greater Atlanta community of Peachtree Corners, where he lives with his wife and daughter.

Latest Articles from this Author

Thuringia, Germany: Shine On
Reshoring: Perfect Storm
News: Briefly Bio

RSS FEED

View all Stories from this Author >>>

ALSO ON **SITE SELECTION**

Authoring - Aerospace: The Great Space Race
1 comment • 2 years ago•
Tyler Pitchford — Very cool; I had no idea this was in Mississippi!

Authoring - Business Climate Overview: Opportunity Abundance
1 comment • 2 years ago•
simguy05 — What is the MDA's position on House Bill 1523? Do you believe there will be any impact to businesses considering …

Authoring - Top Micropolitans of 2015: The Findlay Formula
2 comments • 10 months ago•
joe — So, how can we see the types of projects that qualified in each MSA?

Authoring - Corporate Real Estate Technology: Deep Dive
1 comment • 2 years ago•
Kirk D. Clennan — MAXSUR and UAV Direct are located in Liberty Hill TX. They are on the cutting edge of drone …

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 37

Responding Witness: Robert M. Conroy

Q-37. Refer to the Staffieri Testimony, page 11, lines 9-13. Referring to KU and LG&E, the testimony reads, "Finally, the Companies are prepared to offer a Business Solar option to business and industrial customers who prefer to have an onsite solar facility. Under such an arrangement and subject to Commission approval, the Companies would build, own and operate a solar facility on the customer's property which would provide the customer with some or all of its power needs."

a. Clarify that this reference in the Staffieri Testimony is the only mention of a Business Solar option in KU's rate filing.

b. Confirm, with this reference in the Staffieri Testimony, that KU is not seeking Commission approval of either a specific solar project or any tariff provision related, generally, to a Business Solar option.

c. State whether and if so when KU intends to seek Commission approval of either a specific solar project or any tariff provision related, generally, to a Business Solar option.

A-37.

a. Mr. Staffieri's testimony mentions Business Solar again on line 15 of the page cited above. The testimony of John P. Malloy mentions at page 5 line 18 that Business Solar is among the issues the Consumer Advisory Panel has discussed. To the best of KU's knowledge, those are the only other references to Business Solar in KU's rate filing.

b. KU confirms it is not seeking Commission approval of either a specific solar project or any tariff provision related, generally, to a Business Solar option.

c. KU does not presently intend to offer Business Solar as a tariff offering; rather, Business Solar is offered on a special contract basis, so KU would submit any Business Solar contracts to the Commission for review on the same basis as any other special contract. In addition, if a particular Business Solar facility required a Certificate of Public Convenience and Necessity ("CPCN"), KU would apply to the Commission for CPCN review and approval prior to beginning construction.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 38

Responding Witness: Paul W. Thompson / John P. Malloy

Q-38. Refer to the Staffieri Testimony, pages 12-14.

a. Provide the annual community contributions from the LG&E and KU Foundation and directly from the Companies for each year from 2012 through 2016.

b. Provide a breakdown, by year, of the $2.5 million raised through customer contributions and the Companies' matching funds over the last seven years as part of the WinterCare Energy Fund.

c. Provide a breakdown, by year, of the disbursements from WinterCare Energy Fund for the last seven years.

A-38.

a. LG&E and KU Foundation made the following community contributions for the calendar years 2012 through 2016:

2012	$761,537
2013	$839,948
2014	$696,921
2015	$780,606
2016	$626,850

Kentucky Utilities Company made the following community contributions for the calendar years 2012 through 2016:

2012	$1,111,220
2013	$1,245,988
2014	$1,597,409
2015	$1,650,752
2016	$1,538,158

b. Through the end of 2016, the Company has raised more than \$2.7 million through customer contributions and Companies' matching funds over the last 7 years. See the following tables.

Winterhelp (LG&E)

Year	Customer Contributions	Company Contributions	Total
2010	\$ 104,171	\$ 99,530	\$ 203,701
2011	\$ 103,678	\$ 104,510	\$ 208,188
2012	\$ 99,242	\$ 99,537	\$ 198,779
2013	\$ 112,927	\$ 149,068	\$ 261,995
2014	\$ 128,890	\$ 192,377	\$ 321,267
2015	\$ 114,167	\$ 169,980	\$ 284,147
2016	\$ 117,117	\$ 117,117	\$ 234,234
	\$ 780,192	\$ 932,119	\$ 1,712,311

WinterCare (KU)

Year	Customer Contributions	Company Contributions	Total
2010	\$ 46,562	\$ 61,182	\$ 107,744
2011	\$ 45,334	\$ 106,421	\$ 151,755
2012	\$ 38,734	\$ 106,529	\$ 145,263
2013	\$ 47,701	\$ 116,386	\$ 164,087
2014	\$ 56,652	\$ 100,000	\$ 156,652
2015	\$ 55,035	\$ 100,000	\$ 155,035
2016	\$ 55,568	\$ 100,000	\$ 155,568
	\$ 345,586	\$ 690,518	\$ 1,036,104
Total WinterCare and Winterhelp			**\$ 2,748,415**

c. The Company disbursed all the funds across the seven years. See the following tables.

Winterhelp (LG&E)

Year	Total Disbursements Winterhelp (LG&E)
2010	$ 203,701
2011	$ 208,188
2012	$ 198,779
2013	$ 261,995
2014	$ 321,267
2015	$ 284,147
2016	$ 234,234
	$ 1,712,311

WinterCare (KU)

Year	Total Disbursements WinterCare (KU)
2010	$ 107,744
2011	$ 151,755
2012	$ 145,263
2013	$ 164,087
2014	$ 156,652
2015	$ 155,035
2016	$ 155,568
	$ 1,036,104

Total WinterCare and Winterhelp	**$ 2,748,415**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 39

Responding Witness: Kent W. Blake

Q-39. Refer to the Testimony of Kent W. Blake ("Blake Testimony"), the table at the top of page 5 which shows amounts spent or to be spent through the end of the proposed forecasted test period on capital projects.

a. Provide a breakdown, by account number, of the $152.1 million in generation spend shown for KU and identify how much of the $152.1 million will be spent prior to, and during, the proposed forecasted test period.

b. Provide a breakdown, by account number, of the $222.8 million in electric distribution spend shown for KU and identify how much of the $222.8 million will be spent prior to, and during, the proposed forecasted test period.

c. Provide a breakdown, by account number, of the $88.2 million in customer services and metering spend for KU and identify how much of the $88.2 million will be spent prior to, and during, the proposed forecasted test period.

A-39.

a. See attached.

b. See attached.

c. See attached.

Kentucky Utilities Company
Case No. 2016-00370

	Prior to Forecasted Test Period			Forecasted Test Period			Combined Total		
$ Millions	107	108	Total	107	108	Total	107	108	Total
Generation	64.2	0.9	65.1	75.8	11.2	87.0	140.0	12.1	152.1
Electric Distribution	100.2	6.0	106.2	111.9	4.6	116.6	212.1	10.7	222.8
Customer Services & Metering	15.6	0.0	15.6	72.5	0.1	72.6	88.1	0.1	88.2
Total	**180.0**	**7.0**	**186.9**	**260.3**	**15.9**	**276.1**	**440.2**	**22.8**	**463.1**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 40

Responding Witness: Kent W. Blake

Q-40. Refer to the Blake Testimony, page 9.

a. Identify, by account number, all categories of expense included in the $55,000 lower expense in the proposed forecasted test period for the Companies' Human Resources department compared to the level currently embedded in rates from the last rate case.

b. Provide the total expenses for the Companies' Human Resources department in the proposed forecasted test period and explain why the expenses have decreased by $55,000 since the test year in the last rate case.

c. Of the $55,000, identify the amount applicable to KU.

d. For all financial and administrative functions, provide the projected full-time employee headcount for the proposed forecasted test period.

e. Provide the headcount level projected in the proposed forecasted test period for KU, along with the comparable head count level currently embedded in rates based on KU's last rate case.

A-40. a.

Combined Utilities - O&M Expense Comparison			
FERC Account	**12ME 6/30/16**	**12ME 6/30/18**	**Difference**
920	5,858,939	5,664,171	(194,769)
921	680,295	792,777	112,482
923	704,418	635,167	(69,251)
926	225,736	242,556	16,820
930	31,978	111,329	79,351
Total	**7,501,366**	**7,445,999**	**(55,367)**

b. The decrease within the Human Resources forecast is primarily attributable to a reduction in labor costs. Also attributing the reduction is wellness related costs within outside services.

c.

Kentucky Utilities - O&M Expense Comparison			
FERC Account	**12ME 6/30/16**	**12ME 6/30/18**	**Difference**
920	2,939,573	2,870,227	(69,347)
921	347,581	401,726	54,144
923	358,588	320,900	(37,688)
926	114,091	122,566	8,475
930	16,872	56,242	39,370
Total	**3,776,705**	**3,771,660**	**(5,045)**

d. The projected full-time employee headcount for financial and administrative functions during the forecasted test period is 653 employees. This includes 22 KU employees.

e. The headcount for all Kentucky Utilities employees for the twelve months ended June 30, 2018 is projected at 927. For comparison, the projected headcount for all Kentucky Utilities employees for the twelve months ended Jun 30, 2016 was 954. This does not include headcount for LG&E and KU Services Company.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 41

Responding Witness: Lonnie E. Bellar

Q-41. Refer to the Thompson Testimony, page 11.

a. Prior to the 2015 audit by the North American Electric Reliability Corporation ("NERC"), when had NERC most recently audited the Companies?

b. Explain whether NERC conducts audits on a set schedule or if the entities being audited and the timing of the audits are chosen at random.

If NERC's 2015 audit of the Companies resulted in a report, provide the report. If no report was produced by NERC, explain how the audit's findings were communicated to the Companies.

A-41.

a. To clarify, it was SERC Reliability Corporation ("SERC"), one of NERC's regional entities that audited the Companies in 2015 relating to compliance with the NERC reliability standards. NERC has not audited the Companies since the NERC reliability standards became mandatory in 2007, although on occasion NERC observers have participated in SERC audits of the Companies. Prior to 2015, the most recent SERC audits of the Companies were in 2012.

b. The frequency of SERC audits of the Company is not random. The schedule is based on the NERC Rules of Procedure, which dictate that entities registered as Balancing Authorities and/or Transmission Operators be audited once every three (3) years. Because the Companies are registered for both of these NERC functions, the three (3) year frequency applies.

The 2015 SERC audits did result in two separate audit reports, one for compliance with the Order 693, or legacy, standards and one for compliance with the CIP standards. A redacted copy of the audit report related to the Order 693 or legacy standards is provided pursuant to a petition for confidential protection. The names of the SERC auditors are redacted for their protection according to industry standards. A redacted copy of 2015 LG&E/KU SERC CIP audit report is provided pursuant to a petition for confidential protection. The entire document is considered confidential because of the highly sensitive cyber security information contained therein and the associated risks of disclosure. The names of the SERC auditors are redacted for their protection according to industry standards. The confidential version of the CIP audit report also reflects redaction of Bulk Electric System Cyber System Information ("BESCSI") information, which if exposed, poses serious cyber security threats to bulk electric systems. Industry practice is to keep CIP audits, reports and enforcement actions strictly confidential and protected. As part of the CIP requirements (NERC CIP-011 R1 and R2), the Companies are required to have in place and implement a full and extensive program to protect BESCSI and report any violations of the program.

Due to the highly sensitive nature of the data contained within the CIP program and the possible malicious activities which may result with access to this information, even NERC and SERC take extensive precautions to protect the information. Such practices include ensuring entity names are kept anonymous to ensure no information on published violations can be tied to specific entities, and coming on site to access protected information during any audit or review rather than requesting a copy. Therefore, the Companies have redacted both audit reports as attached, to provide information as requested but also to meet CIP requirements and to properly protect highly sensitive information. Unredacted versions of both audit reports may be viewed at the Companies' offices upon request. Review of the unredacted versions of the audit reports will be permitted subject to the execution of a confidentiality agreement with restrictive terms and conditions that exceed the confidentiality agreements provided to parties to date.

The entire attachments are Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 42

Responding Witness: Lonnie E. Bellar

Q-42. Refer to the Thompson Testimony, pages 11-12, and Exhibit PWT-1. Of the generating facilities in which KU has an ownership interest, identify any plants which are scheduled for retirement by the end of calendar year 2021.

A-42. There are no scheduled plant retirements by the end of calendar year 2021.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 43

Responding Witness: David S. Sinclair

Q-43. Refer to the Thompson Testimony, page 17, lines 3-7. Provide separately the capacity factors at which each of the Paddy's Run units operated for 2015 and 2016.

A-43. The 2015 and 2016 capacity factors for each of the Paddy's Run units are shown in the following table.

	2015	**2016**
Paddy's Run 11	0.01%	0.10%
Paddy's Run 12	0.10%	0.10%
Paddy's Run 13	13.2%	7.2%

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 44

Responding Witness: John K. Wolfe

Q-44. Refer to the Thompson Testimony, page 38, lines 23-24. State whether this statement indicates that only 50 percent of KU's customers will benefit from the Distribution Automation ("DA") program.

A-44. Fifty percent of the combination of LG&E and KU customers will benefit directly from the Distribution Automation program. Thirty-nine percent of KU customers will benefit directly from the program.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 45

Responding Witness: John K. Wolfe

Q-45. Refer to the Thompson Testimony, pages 40-41.

a. Refer to page 41, lines 9-17. Explain how it was determined that the benefits listed are significant enough to justify an investment of $112 million in the proposed DA program.

b. Refer to lines 19-22. Provide the analysis discussed in this paragraph.

A-45. a. Justification for the investment can be found in Section 2 beginning on page 5 of Exhibit PWT-5 of Mr. Thompson's testimony.

b. The analysis can be found in Section 3 on page 23 of Exhibit PWT-5 of Mr. Thompson's testimony.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 46

Responding Witness: John K. Wolfe

Q-46. Refer to Thompson Testimony, Exhibit PWT-5, page 5 of 29. State whether the chart on the bottom half of the page indicates that DA is needed more by KU's sister company, LG&E, than by KU to improve customer satisfaction.

A-46. Prioritization for DA implementation is based on circuit reliability performance data along with circuit characteristics such as availability of existing circuit ties. This single prioritization methodology is applied across both LG&E and KU service territories and determines optimum locations to achieve DA benefits or the need for DA. Circuits will be reprioritized on an annual basis to take advantage of the most up-to-date reliability data. This methodology applied to the current most recent data results in roughly sixty percent of the total DA investment taking place in the LG&E service territory and roughly forty percent of the DA investment taking place in the KU and ODP service territories. DA investments will be allocated to the utilities when and where they actually take place.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 47

Responding Witness: John K. Wolfe

Q-47. Refer to the Thompson Testimony, pages 38-43, and Exhibit PWT-6.

a. Page 41, lines 1-2 indicate that $23 million in capital expenditures on the proposed DA program will be incurred by the end of the proposed forecasted test period. Provide the amount of such expenditures expected to be incurred prior to, and during, the proposed forecasted test period.

b. Page 41, lines 4-5 indicate that $1.16 million in DA-related operation and maintenance ("O&M") expenses will be incurred by the end of the proposed forecast test period. Provide the amount of DA-related O&M expenses to be incurred prior to, and during, the proposed forecasted test period.

c. Page 41, lines 3-4 indicate that $6 million in DA-related O&M expenses is expected to be incurred over the seven-year implementation period. Exhibit PWT-6, page 1 of 1, contains a side-by-side comparison of the annual O&M expenses and O&M savings from the DA program for the period 2023 through 2051.

1) Provide the $6 million in DA-related O&M expenses for the seven-year implementation period on an annual basis for each of the seven years.

2) Explain how the expected annual O&M savings shown in Exhibit PWT-6 were developed.

3) Explain whether DA-related savings have been quantified for the seven-year implementation period. If they have been quantified, provide them. If they have not been quantified, explain why.

A-47.

a. $330 thousand for engineering and design will be incurred prior to the proposed forecasted test period. The remaining $22.7 million will be incurred during the forecasted test period.

b. The total $1.16 million in DA-related operation and maintenance expenses referenced will be incurred during the forecast test period.

c. (1)

Year	2016	2017	2018	2019	2020	2021	2022
$000's	0	440	1,362	1,470	1,336	1,371	42

Note: The financial model referenced includes O&M expenses associated with the DMS over the depreciable life of the DMS asset which ends after 2021. The Companies believe this is the reasonable period for the analysis. Annual ongoing O&M expenses modeled beyond 2021 reflect communication costs associated with the SCADA connected reclosers. A financial scenario including escalated ongoing O&M DMS expenses, as well as assumed DMS upgrade costs and timing through 2051 was completed. This scenario showed the "do nothing" alternative to be the lowest NPVRR of the alternatives evaluated. The Companies believe this scenario is based on an unreasonable period for the analysis because of the uncertainties associated with the 30-year IT system assumptions. Recognizing the uncertainty of 30-year IT system related assumptions and noting reliability improvement is the primary objective of the DA program, completion of the DA program remains the recommended alternative based on the justification described in Exhibit PWT-5 of Mr. Thompson's testimony.

(2) The annual O&M savings were developed by estimating the value of operational efficiency improvements such as the DMS system fault location predictions reducing the time required to locate faults, SCADA connected reclosers eliminating the need for some manual switching operations and SCADA connected reclosers permitting the remote application of caution cards.

(3) DA related savings have been quantified during the 7-year implementation period. Savings shown reflect combined savings between LG&E and KU.

Year	**Expected O&M Savings ($'000s)**
2016	0
2017	0
2018	0
2019	50
2020	100
2021	150
2022	180

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 48

Responding Witness: Daniel K. Arbough

Q-48. Refer to the Arbough Testimony, pages 12- 13, and Exhibit DKA-6, page 1 of 1. Explain whether the peer group against which the Companies compare their debt costs is selected by the Companies, by another party on the Companies' behalf, or by an independent third party.

A-48. The peer group against which the Companies compare their debt costs was elected by the Companies. The Companies have used this same peer group since 2006. The group includes most of the major utilities in the region.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 49

Responding Witness: Daniel K. Arbough

Q-49. Refer to the Arbough Testimony, Exhibit DKA-1, page 1 of 1, regarding the financial planning software utilized by the Companies. Under the Ul Planner, there is a calculation for Interest & Dividends.

a. Explain how dividends, if any, were reflected in the base year and test year.

b. Provide, by date, the amount of dividends KU has paid since 2010. Consider this an ongoing request throughout this proceeding

A-49.

a. Dividends are calculated every quarter in the projected portion of the base and test year using a payout assumption of 65% of the previous quarter's net income for the utilities. See Tab 16 Filing Requirement Section 16(7)(c) Item A page 15 of 18.

b. The attached file shows both dividends paid by KU to its parent, LG&E and KU Energy (LKE), and the equity contributions made by LKE to KU.

Payment Date	Summary of Dividends Paid by KU to LKE since 2010	Summary of Capital Contibutions Paid by LKE to KU since 2010
9/30/2010	$ 50,000,000	$ -
Total Paid 2010	50,000,000	-
3/30/2011	$ 31,000,000	$ -
6/29/2011	37,000,000	-
9/29/2011	19,500,000	-
12/29/2011	36,000,000	-
Total Paid 2011	123,500,000	-
3/29/2012	$ 24,000,000	$ -
6/28/2012	24,000,000	-
9/27/2012	19,500,000	-
12/28/2012	32,000,000	-
Total Paid 2012	99,500,000	-
3/27/2013	$ 13,000,000	$ 50,000,000
6/27/2013	42,000,000	42,000,000
9/27/2013	28,000,000	-
12/30/2013	41,000,000	65,000,000
Total Paid 2013	124,000,000	157,000,000
3/28/2014	$ 37,000,000	$ 40,000,000
6/27/2014	49,000,000	26,000,000
9/29/2014	26,000,000	-
12/30/2014	36,000,000	25,000,000
Total Paid 2014	148,000,000	91,000,000
3/30/2015	$ 30,000,000	$ -
6/29/2015	51,000,000	-
9/29/2015	25,000,000	-
12/30/2015	47,000,000	-
Total Paid 2015	$ 153,000,000	$ -
3/30/2016	$ 64,000,000	$ -
6/29/2016	49,000,000	20,000,000
9/29/2016	84,000,000	-
12/29/2016	51,000,000	-
Total Paid 2016	$ 248,000,000	$ 20,000,000

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 50

Responding Witness: Adrien M. McKenzie

Q-50. Refer to the Direct Testimony of Adrien M. McKenzie, CFA ("McKenzie Testimony"), page 11, line 3, and Exhibit No. 4, page 1. Confirm that only three of the 22 proxy group utilities have higher year-end 2015 common equity ratios, and only two have higher projected common equity ratios than the 53.28 percent common equity ratio used by KU.

A-50. With respect to the holding companies on page 1 of Exhibit No. 4, Mr. McKenzie agrees with the above statement. With respect to page 2 of Exhibit No. 4, twenty operating companies had common equity ratios at year-end 2015 equal to or higher than the 53.28 percent ratio used by KU.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 51

Responding Witness: Adrien M. McKenzie

Q-51. Refer to the McKenzie Testimony, pages 20-21.

a. Explain why Duke Energy Corporation is not included in the proxy group.

b. Explain why including KU's parent company, PPL Corporation, in the proxy group is not circular.

c. The following companies had acquisition activity in the past year. Explain why it is appropriate to include them in the proxy group.

1) Black Hills Corporation[2]

2) Southern Company[3]

3) DTE Energy Company[4]

A-51.

a. Duke Energy Corporation was excluded from the proxy group due to its recent acquisition of Piedmont Natural Gas, with Value Line noting that its estimates did not yet include the impact of the transaction.

b. The quantitative methods used to estimate the cost of equity are based on capital market information and investors' expectations for PPL, and are not directly a function of the authorized ROE for KU that will be established in this proceeding. As a result, while investors' expectations as to future regulatory decisions would be one consideration relevant to investors, there is no direct circularity between the application of the quantitative methods discussed in Mr. McKenzie's testimony to PPL and the authorized ROE decided in this proceeding. In Mr. McKenzie's experience, utilities (or their publicly traded parent companies) are routinely included in proxy groups for purposes of estimating the cost of equity in regulatory proceedings, and provide a

[2] October 28, 2016 issue of The Value Line Investment Survey at 2226.
[3] November 18, 2016 issue of The Value Line Investment Survey at 151.
[4] December 16, 2016 issue of The Value Line Investment Survey at 908.

meaningful guide when considered along with information for other companies of comparable-risk.

c. Merger and acquisition activity is not uncommon in the utility industry, and the fact that a firm may have been involved in a past transaction does not provide a basis to exclude it from the proxy group. Because the process of estimating the cost of equity is inherently forward-looking, the impact of any past mergers and acquisitions is already reflected in the capital market data used to estimate the cost of equity. In other cases, the magnitude of the merger relative to the utility may be small, and there would be no reason to expect any distortions related to the transaction. With respect to Black Hills Corporation, for example, its acquisition of SourceGas was completed on February 12, 2016. Accordingly, the investment community is well aware of the transaction, and their assessment of the relative impact is reflected in the data used to estimate the cost of equity. Similarly, Southern Company's acquisition of AGL Resources was completed July 1, 2016, and while Southern Company is also in the process of acquiring a 50% interest in a gas pipeline from Kinder Morgan, this transaction is small relative to Southern Company's total capitalization. Meanwhile, DTE Energy's purchase of certain midstream natural gas assets was announced on September 26, 2016 and completed on October 20, 2016. Again, there is no indication that this asset purchase led to a distortion of the inputs used to apply the various quantitative models used to estimate the cost of equity.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 52

Responding Witness: Adrien M. McKenzie

Q-52. Refer to the McKenzie Testimony, page 44, and Exhibit No. 7 to the McKenzie Testimony.

a. Explain why it was necessary to weight the firms in the calculations as described on page 44, lines 3-4, as opposed to performing the calculations on an unweighted basis.

b. Provide a copy of Table 7.3 referenced in footnote (f) on pages 1 and 2 of Exhibit No. 7.

A-52.

a. Market value weights were used in order to be consistent with the S&P 500 Index, which is a market capitalization weighted index.

b. A copy of the requested document is included in Mr. McKenzie's work papers, which were provided in response to AG 1-249.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 53

Responding Witness: Adrien M. McKenzie

Q-53. Refer to the McKenzie Testimony, page 52, and to Exhibit No. 9.

a. State whether triple-S utility bond yields were used in the Risk Premium analysis, as stated on page 52, or whether Baa utility bond yields were used as indicated in Exhibit 9, pages 1 and 2.

b. Refer to Exhibit No. 9, page 1. Provide an update to the Risk Premium Cost of Equity using the average bond yield on public utility bonds and Baa subset for the most current three months.

c. Refer to Exhibit No. 9, page 3. Provide an update of the Risk Premium calculation when Allowed ROEs are available from Regulatory Research Associates for calendar year 2016.

A-53.

a. Mr. McKenzie's testimony at page 52 references yields on triple-B bonds. The term "triple-B" refers to bonds rated Baa3, Baa2, and Baa1 by Moody's Investors Service (Moody's), which make up the Baa bond yield index published by Moody's and referenced in Mr. McKenzie's application of the risk premium approach. Accordingly, reference to the term "triple-B public utility bond yields" is synonymous with "Baa bond yields."

b. The requested analysis, which is based on three-month average bond yields for the period October – December 2016, is being provided in Excel format.

c. The requested analysis, which incorporates Regulatory Research Associates data for 2016, as well as three-month average bond yields for the period October – December 2016, is being provided in Excel format.

The attachments are being provided in separate files in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 54

Responding Witness: Adrien M. McKenzie

Q-54. Provide the most current ROE awarded by each respective regulatory agency and the date of the award for the proxy group of gas and electric utilities or for the utility subsidiary if the proxy group member is a holding company.

A-54. Mr. McKenzie did not conduct a research study to identify the most current ROE authorized for the respective utilities covered by his Utility Group in the course of preparing his Direct Testimony; nor was such a study necessary to support his conclusions and recommendations. Nevertheless, the Value Line Investment Survey reports contain data regarding current authorized ROEs, with the average authorized ROE reported by Value Line for the firms in the Utility Group being presented below:

	Company	Authorized ROE
1	Alliant Energy	10.90%
2	Ameren Corp.	9.12%
3	Avangrid, Inc.	NA
4	Avista Corp.	9.50%
5	Black Hills Corp.	9.83%
6	CenterPoint Energy	10.00%
7	CMS Energy Corp.	10.30%
8	Consolidated Edison	9.10%
9	DTE Energy Co.	10.30%
10	Entergy Corp.	10.00%
11	Eversource Energy	9.43%
12	Exelon Corp.	9.50%
13	NorthWestern Corp.	10.10%
14	PG&E Corp.	10.40%
15	PPL Corp.	NA
16	Pub Sv Enterprise Grp.	10.30%
17	SCANA Corp.	10.43%
18	Sempra Energy	10.30%
19	Southern Company	12.50%
20	Vectren Corp.	10.28%
21	WEC Energy Group	9.61%
22	Xcel Energy Inc.	9.80%
	Average	**10.08%**

The underlying data is contained in the Excel file being provided in response to PSC 1-54, with copies of the source documents being provided in response to AG 1-249.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 55

Responding Witness: David S. Sinclair

Q-55. Refer to the Direct Testimony of David S. Sinclair ("Sinclair Testimony"), page 25, lines 6-8. Explain why eight curtailment events were included in the annual generation forecast when no curtailments have been called since January 2014.

A-55. Historically, the need for curtailment events has been driven by a build-up of load resulting from extreme weather conditions experienced over consecutive weekdays. No curtailments have been called since January 2014 primarily because the Companies have not experienced these load conditions. Consistent with the CSR tariff, the Companies' production cost model simulates CSR as a resource when all available units have been dispatched or are being dispatched, and all off-system sales have been or are being curtailed. Inputs to the model are long-term planned maintenance schedules as well as monthly rates for short term forced and discretionary maintenance outages. Unlike in the real world, where certain discretionary outages are often moved based on short term load forecasts (next two weeks), these outage timings are fixed in the model. Therefore, there can be certain hours where the modeled resources can be very tight, particularly during maintenance season. As a result, four of the eight curtailment events in the forecast period occur in shoulder months where discretionary changes could eliminate or reduce the likelihood of a curtailment event. As Mr. Sinclair stated in his testimony on page 25, lines 8-9, "Whether these events occur will be subject to actual load and system conditions."

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 56

Responding Witness: David S. Sinclair

Q-56. Refer to the Sinclair testimony, pages 24-25. These pages refer to a curtailment that happened on January 30, 2014.

a. Explain how a combustion turbine ("CT") is categorized as either a primary CT or a secondary CT.

b. State the load level at which KU's and LG&E's secondary combustion turbines operated during the curtailment event.

c. In general, explain how KU and LG&E determine which of their Curtailable Service Rider ("CSR") customers are curtailed.

A-56.

a. The Companies' primary CTs are all large-frame combustion turbines that were commissioned since 1994, with nameplate capacities ranging from 123 to 199 MW. The Companies' primary CTs comprise Brown 5-11, Paddy's Run 13, and Trimble County 5-10. In contrast, the Companies' secondary CTs were commissioned between 1968 and 1970 and are much smaller, with nameplate capacities ranging from 16 to 33 MW. The Companies' secondary CTs comprise Cane Run 11, Haefling 1-2, Paddy's Run 11-12, and Zorn 1. In addition to relative age and size, the primary CTs are more efficient, with net average heat rates ranging between 10 and 13 MMBtu/MWh, compared to net average heat rates ranging between 14 and 18 MMBtu/MWh for the secondary CTs.

b. Haefling 1-2 were operating at full load during the curtailment event. Cane Run 11 was dispatched prior to the curtailment event, came online during the event, and operated at full load. The natural gas supply for Paddy's Run 11-12 and Zorn 1 is provided by the Company's gas distribution system. Because gas demand was very high during this curtailment event, the fuel supply to these units was unavailable.

c. In general, all CSR customers are curtailed during a curtailment event.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 57

Responding Witness: David S. Sinclair

Q-57. Refer to the Sinclair Testimony, Exhibit DSS-2. Provide the Excel spreadsheets containing the inputs, model specifications, outputs, and adjustments to support Exhibit DSS-2.

A-57. See the attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 58

Responding Witness: John P. Malloy

Q-58. Refer to KU's application, paragraph 14, the Testimony of John P. Malloy ("Malloy Testimony"), and Exhibit JPM-1 ("Ex. 1").

a. The last sentence in paragraph 14 of the application refers to the forecasted amount of incremental O&M expenses, $13.7 million, that is expected to be incurred during the deployment phase of the proposed AMS. Provide the amount and derivation of such incremental O&M expenses forecasted to be incurred during the proposed test year.

b. The Malloy Testimony, page 17, and Ex. 1, pages 30-44, reference the long-term benefits and costs related to the proposed AMS systems. Provide the amounts, if any, of such benefits and costs that are included in the proposed test year.

A-58. Note that in the table below the sum of the individual items shown and the total provided might differ due to rounding:

a. O&M Expenses ($M)		**Test Year**
Meter Asset Labor	$	1.1
Backup Hardware Ongoing Maintenance		0.1
Network Infrastructure Incremental Labor		0.0
Network Infrastructure Maintenance		0.0
Oracle Database License Maintenance		0.2
Server Hardware Maintenance		0.0
Storage Hardware Maintenance		0.1
ePortal License		0.1
Field Maintenance		0.0
Electric Meter Base Repair		1.2
	$	**2.9**

b. Benefits ($M)		**Test Year**
Avoided Meter Capital Benefit	$	1.0
Avoided and Deferred IT Benefit		1.2
	$	**2.2**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 59

Responding Witness: John P. Malloy

Q-59. Refer to the Malloy Testimony, page 14, lines 20-22. By account number, provide a breakdown of the $60 million to be spent for KU in customer service capital investments related to the AMS.

A-59. The $60 million in AMS capital investment for KU through June 30, 2018, which was budgeted entirely to FERC account 107, is shown in the table below.

Capital Category	**Cost ($M)**	
Meters and Installation	$	38
Network and Installation		4
Meter Asset / Operations Management		3
Meter Data Management		4
System / SAP Integration		11
Total	**$**	**60**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 60

Responding Witness: John P. Malloy

Q-60. Refer to the Malloy Testimony, page 17, lines 8-15. Provide the basis for the 20-year estimated useful life for the AMS meters.

A-60. Based on experience and discussions with the planned meter vendor, Landis + Gyr, the Company expects meters and indices deployed during the program to last 20 years on average. For example, as noted in Mr. Malloy's testimony at lines 9-12 on page 17, KU deployed over 4,000 meters and a Landis + Gyr TS1 (Turtle®) system in 1999 that continue to operate today.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 61

Responding Witness: John P. Malloy

Q-61. Refer to the Malloy Testimony, page 18, lines 18-20. State whether the meters installed under the AMS Customer Offering included in KU's DSM program are the same meters to be installed as part of the proposed AMS. If not, explain.

A-61. Generally, they are the same. The meters installed as part of the DSM AMS program do not have remote service switches. Meters planned for installation under the proposed AMS program will have remote service switches subject to technical and operational constraints (i.e. remote service switches are not available for meters above 200 amps). This is the only difference between the planned meters and those already deployed.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 62

Responding Witness: Robert M. Conroy / Christopher M. Garrett

Q-62. Refer to the Malloy Testimony, pages 23-24, concerning the retirement of existing meters and the cost-benefit analysis's assumption of a five-year recovery period for the proposed regulatory asset.

a. Explain how the Companies determined the five-year cost recovery assumption for the proposed regulatory asset.

b. Provide the remaining useful life of the meters to be retired.

c. Explain whether the Companies were aware that in Case No. 2011-00096[5] the Commission found that a regulatory asset associated with retired meters was to be amortized over the life of the new meters for ratemaking purposes.

A-62.

a. The Companies have utilized a five-year amortization period for cost/benefit analyses only and have not included any amortization in the current case. However, the Companies believe a five-year amortization comports well with the ratemaking principles of gradualism and cost causation. Concerning gradualism, a five-year amortization should minimize any rate shock that might be caused by too short a recovery period. Concerning cost causation, a five-year amortization should ensure that those who received the benefit of the meters prior to retirement are likely to pay the cost of those meters, while minimizing the imposition of retired meter costs on future customers who did not use the retired meters.

b. See the Spanos Testimony, Exhibit JJS-KU-1, page 59. The remaining life of the meters to be retired is 4.3 years. Existing meters have an average useful life of 28 years.

---

[5] Case No. 2011-00096, *Application of South Central Kentucky Rural Electric Cooperative Corporation for an Adjustment to Rates* (Ky. PSC Mar. 30, 2012).

c. The Companies are aware of the Commission's holding in Case No. 2011-00096, but respectfully contend a five-year amortization period is appropriate for the reasons given above.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 63

Responding Witness: John P. Malloy

Q-63. Refer to the Malloy Testimony, page 26, lines 17-23.

a. The testimony states that customers will not be allowed to opt out of the AMS deployment. Provide the initial upfront cost and monthly cost that a customer would incur if opt-outs were allowed. Include the supporting calculations in the response.

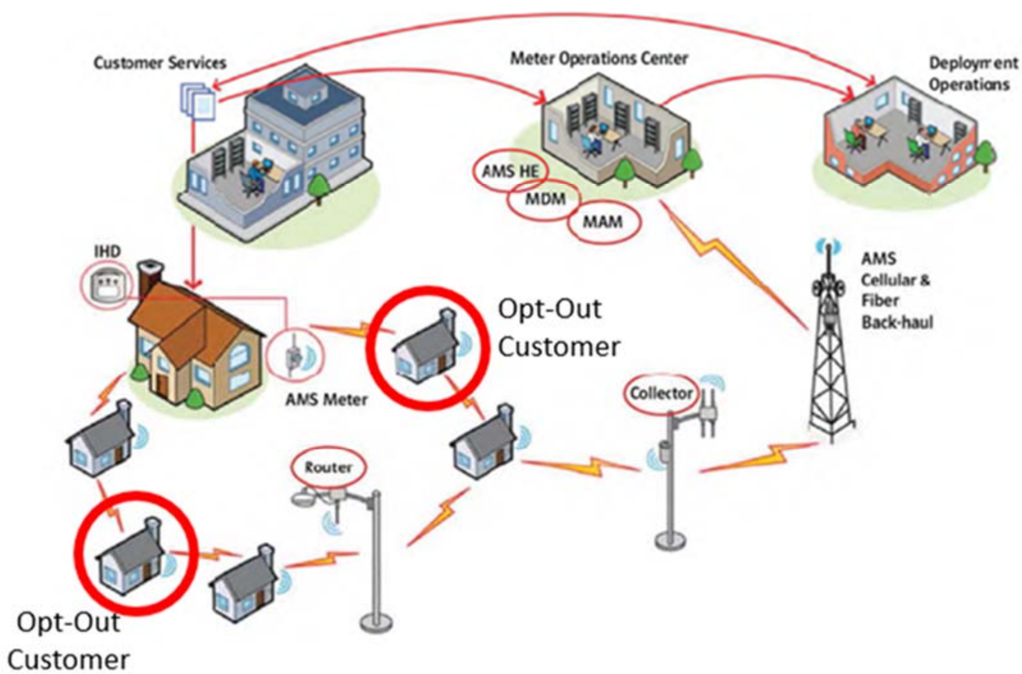
b. Explain how the removal of a single meter affects the ability of surrounding meters to consistently report their readings.

A-63.

a. Opt-out costs are calculated based upon the number of customers electing to opt-out of AMS, the degree these opt-out customers are dispersed across the service territory which equates to the amount of time it takes to read the meters on a monthly basis. Thus, initial opt-out costs estimates are likely to be grossly misstated. Notwithstanding this, the Company did perform some initial calculations to estimate what the cost of opt-out might be. The Company elected to forego an initial AMS opt-out cost due to administration issues of determining when a customer must pay an initial fee and when they would not be required (i.e. move-in, transfer service to another premise, etc.). The Companies' initial estimate was calculated to be $15.75 per month based upon 0.8% customers opting-out and 10 minutes per meter read. See attached.

b. See the diagram on page 13 of 169 in Exhibit JPM-1. AMS will primarily use a radio frequency ("RF") mesh network for meter communications, though in some instances cellular may be required because of the remote location of a premise. A collector is used to talk to the meters and transfer the information from the meters to Company computers. However, not all meters can reach the collector with their radio. These meters then search out another meter in the mesh network to transfer its information to the collector. When one meter communicates through another meter it is called a "hop." The network is designed to minimize hops but there will be meters which may have to hop three to five meters to reach a collector and transfer its information back to Company computers. The cause for these hops varies from meters where RF is hard to reach like a basement or crawl-space, to rural areas where there are long distances from the meter to the collector.

Consequently, when a meter is removed from the mesh network it creates a hole in the mesh network. This hole may increase costs to communicate with the remaining meters when additional routers, collectors, cellular meters, or manual meter reading must be deployed for the remaining AMS metered customers. For example, see the diagram on page 13 of 169 in Exhibit JPM-1, which is replicated below for convenience with the addition of two red circles indicating opt-out customers. In this example the house with the brown roof and the one next to it, has no path to the router or collector because of the opt-out customers.



Kentucky Utilities Company
AMS Opt-Out - Electric
Cost Justification

Opt-Out Costs - Keep Existing Meter

Category	Cost Type	Description	Cost
Meter Reading System	Implementation	Cost to modify existing software system.	$ 33,858
	Recurring	Cost to annual upgrade existing software system.	$ 30,594
	Recurring	The software license costs which must be renewed each year.	$ 19,172
Meter Reading Equipment	Recurring	Cost of handheld and equipment maintenance/replacement.	$ 2,855
Meter Costs	Implementation	Cost of new meter with disabled radio.	$ -
Meter Readers	Recurring	Ongoing costs for meter readers, dispatchers, and supervisors, plus vehicle costs.	$ 660,263
Mesh Network	Implementation	Cost of additional relays, access points, and supporting infrastructure, assuming an even distribution of lost endpoints throughout the territory.	$ 18,765
	Recurring	Ongoing maintenance costs.	$ 408
Enrollment	Implementation	Updates to billing system to handle opt-out enrollment, training for staff, and testing.	$ 91,783
Billing and Reporting	Implementation	Updates to billing system to handle opt-out billing and reporting, training for staff, and testing.	$ 91,783
		Implementation Total	$ 236,188
		Recurring Total	$ 713,293

Proposed Opt-Out Rate Structure
Opt-Out Customers Who Keep Their Existing Meter

1.	Number of Meters targeted for AMS Replacement	530,331
2.	Percent Opt-Out	0.80%
3.	Estimated Customers Opt-Out	4,243
4.	**One-Time Fee**	$ -
	One-Time Fixed Costs	
5.	Enrollment, Billing and Reporting	$ 183,566
6.	Meter Reading System	$ 33,858
7.	Mesh Network	$ 18,765
8.	Less: Capital Collected via up-front fee	$ -
9.	Subtotal - Remaining Fixed Costs to be recovered	$ 236,188
10.	Remaining Fixed Costs divided by All Opt-Out Customers	$ 55.67
11.	Monthly Levelized Revenue Requirement Recovery of Fixed Costs per Customer[1]	$ 1.74
	Annual Recurring Costs	
12.	Meter Reading System	$ 49,766.73
13.	Meter Reading Equipment	$ 2,855.47
14.	Meter Readers	$ 660,263.01
15.	Mesh Network	$ 407.92
16.	Annual Recovery of on-going Costs	$ 713,293.14
17.	Monthly Recovery of Recurring Costs per customer	$ 14.01
18.	Total Monthly Fee (11 + 16)	$ 15.75

1. 5 year amortization rate including a return component

Kentucky Utilities

Present Value of Replacement Plant as a Percentage of Original Cost

Year (1)	5-Year R3 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 2.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.2989	0.7011	0.7011	1.0200	0.7152	0.9346	0.6684	0.6684
2	96.8953	2.4035	3.1047	1.0404	2.5006	0.8734	2.1841	2.8525
3	90.7990	6.0963	9.2010	1.0612	6.4695	0.8163	5.2810	8.1335
4	78.0273	12.7718	21.9727	1.0824	13.8246	0.7629	10.5467	18.6802
5	54.7415	23.2857	45.2585	1.1041	25.7093	0.7130	18.3304	37.0106

Present Value of Replacement Plant as a Percentage of Original Cost: 37.0106

Kentucky Utilities
Meter Pulse Charge

1	Present Value of Replacement Plant as a Percentage of Original Cost			37.01
2	Original Cost Basis (100)			100
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost			137.01
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)			0.02078
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)			2.85%
6	O&M Percentage			0.28%
7	Distribution O&M 12 Months Ended August 31, 2016	$ 56,521,716		
8	Distribution Plant in Service as August 31, 2016	$ 1,670,161,484		
9	Total Monthly Revenue Requirement as Percentage of Original Cost			3.13%
10	Remaining Fixed Costs per Opt-Out Customers		$	55.67
11	Monthly Charge		$	1.74

Kentucky Utilities
Levelized Carrying Charge Analysis

Capital Structure:

	Amount	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short-Term Debt	$ 17,283	0.29%	0.64%	0.00%	38.90%	0.00%
Long-Term Debt	2,341,491	46.39%	4.06%	1.89%	38.90%	1.15%
Common Equity	2,688,476	53.27%	10.23%	5.45%		5.45%
	$ 5,047,249			7.34%		6.60%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	5.760%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	3.280%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Kentucky Utilities
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		38.90%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,013	
Levelized Revenue Requirement		$249	
Levelized Carrying Charge Rate		24.94%	
Level of Investment that can be Supported by		4.01	Times Net Revenue

Kentucky Utilities
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		38.90%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,013	
Levelized Revenue Requirement		$249	
Levelized Carrying Charge Rate		24.94%	
Level of Investment that can be Supported by Revenue		4.01	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ 1,000							$ -	-	$ -	-	$ -	1.000000	$ -
1		200	800	200	800	-	-	800	0	59	37	296	0.931651	276
2		200	600	320	480	47	47	553	0	41	26	266	0.867974	231
3		200	400	192	288	(3)	44	356	0	26	17	243	0.808649	196
4		200	200	115	173	(33)	11	189	0	14	9	223	0.753379	168
5		200	-	115	58	(33)	(22)	22	0	2	1	203	0.701886	142
6		-	-	58	-	22	-	-	-	-	-	-	0.653913	-
														$ 1,013

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 64

Responding Witness: John P. Malloy

Q-64. Refer to the Malloy Testimony, Exhibit JPM-1.

a. Refer to page 14 of 169.

1) Refer to the bullet point titled "Reading frequency" which states that energy consumption data is typically transmitted three to four times a day. State the number of times consumption data will be transmitted per day.

2) Refer to footnote 9. State whether the MV90 meters are read remotely.

b. Refer to page 15 of 169, the fourth bullet point. Provide details of, and plans for, Zigbee communication through in-home devices.

c. Refer to page 28 of 169, which states that KU is developing detailed plans and will begin negotiation with all of its partners. State whether KU plans to issue a Request for Proposals for the AMS. If not, explain.

d. Refer to page 31 of 169. Confirm that the $166 million ePortal Benefit shown on the graph is revenue loss to KU and LG&E.

e. Refer to page 36 of 169, Section 7.1.6., which states that "non-AMS meters taken out of service can be retired or used as replacements in areas that AMS has not been made available." Explain whether this statement indicates that some areas will remain in which AMS will not be made available.

f. Refer to page 38 of 169, middle of the page.

1) Provide the supporting calculations for the amounts that appear in the row "Meters and Network" in the Operating Costs section.

2) Provide the supporting calculations for the amounts that appear in the row "Total Benefits."

g. Refer to pages 152-158 of 169. Provide all assumptions, calculations and spreadsheets used to support the savings calculated on these pages.

h. Refer to pages 159-166 of 169, Appendix A-6. Provide an explanation of the evaluation performed in this appendix.

i. State whether all of the proposed AMS meters will be capable of measuring demand. If not, state which rate classes will have AMS meters capable of measuring demand.

A-64.

a.

1) Consumption data will be transmitted at least 3 times per day from the meter to the AMS head-end.

2) 110 MV90 meters are read remotely of the 3,827 total MV90 meters. The remaining meters are manually read. The Companies are working to remotely read all MV 90 meters.

b. The Companies have no plans to deploy in-home devices and thus do not plan to use the ZigBee communication capabilities.

c. KU does not plan to issue a Request for Proposals (RFP) for AMS. The Companies issued an RFP for the DSM AMS Opt-In and considered full deployment as part of the evaluation of those proposals. Full deployment was part of the evaluation of potential DSM AMS vendors to help ensure system interoperability if the Companies moved to a full deployment of AMS before the end of the useful life of deployed DSM AMS equipment.

d. The $166 million (nominal) shown on page 31 of 169 will be lost revenue to the Companies. It was not included in the Company's revenue forecasts because it would occur outside of the test year. Thus, any loss from these customer savings would be reflected in future rate cases. Note that the Companies would not incur fuel costs necessary to provide the $166 million in avoided energy purchases, so the net revenue reduction to the Companies would be less than $166 million.

e. The statement on page 36 of 169, "non-AMS meters taken out of service can be retired or used as replacements in areas that AMS has not been made available" describes the Companies' intention to reuse existing meters during the AMS deployment phase of the project. Meter installation will take more than two years to complete (see page 45 of 169) and during this time new construction, demolition, failed meters, and other events may require a non-AMS meter installation or exchange. Placing an AMS meter ahead of network communication creates operational problems and is not advisable. Thus, the

Companies plan to use existing meters as needed to provide service and a smooth transition to AMS. The Companies are aware that there are about 30,000 customers whose premises do not have cellular coverage and may be costly to serve with a mesh network; however, the goal is to replace all meters with AMS meters.

f. See the response to part g. below.

g. See the attachment being provided in Excel format. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. In addition, certain limited information that does not affect the data or calculations is being redacted as attorney work product; all such redactions are clearly indicated.

h. The evaluation performed in this appendix is the standard capital evaluation model used by the Company to analyze costs and benefits of potential projects. The model is constructed to look at costs and benefits from a customer perspective and take the time value of money into consideration for each expense and benefit. The summary sheet on page 160 of 169 "NPV Revenue Requirements" demonstrates the value of the project - At a value of zero the costs equal the benefits - Thus, the more negative the greater the value to customers. The ($30,164) value on this line indicates there is a little more than $30 million of benefits in excess of costs on a present value basis (time value of money).

i. All of the proposed AMS meters will be capable of measuring demand.

The attachment is Confidential and provided under seal in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 65

Responding Witness: Robert M. Conroy

Q-65. Refer to the Conroy Testimony, page 4. Provide the Edison Electric Institute report referenced on lines 18-19.

A-65. The relevant portions of the requested report are attached. The regional comparison includes the states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, Jew Jersey, Ohio, Pennsylvania, West Virginia and Wisconsin.

Average Rates

(in cents/kilowatthour)

Residential Average Rates

		12 Months Ending 6/30	
		2015	**2016**
Average For South Atlantic			
	generation	7.90	8.01
	transmission	0.82	0.90
	delivery	4.14	4.46
	total rate	11.55	11.61
total for all utilities (IOUs, munis, coops, etc.)		11.76	

East South Central

Alabama

		2015	2016
Alabama Power Company			
	total rate	11.97	12.37
Average For Alabama			
	total rate	11.97	12.37
total for all utilities (IOUs, munis, coops, etc.)		11.64	

Kentucky

		2015	2016
AEP (Kentucky Power Rate Area)			
	total rate	9.80	11.40
Duke Energy Kentucky			
	total rate	8.92	8.76
Kentucky Utilities Company			
	total rate	9.31	9.91
Louisville Gas & Electric Company			
	total rate	10.29	10.43
Average For Kentucky			
	total rate	9.63	10.18
total for all utilities (IOUs, munis, coops, etc.)		9.98	

Average Rates

(in cents/kilowatthour)

Residential Average Rates

Hawaii

Hawaii

		12 Months Ending 6/30 2015	2016
Hawaii Electric Light Company	total rate	38.84	32.18
Hawaiian Electric Company	total rate	32.36	26.39
Maui Electric Company (Lanai)	total rate	42.16	34.53
Maui Electric Company (Maui)	total rate	35.05	29.05
Maui Electric Company (Molokai)	total rate	43.08	33.99
Average For Hawaii	total rate	33.91	27.78
	total for all utilities (IOUs, munis, coops, etc.)	33.98	

Average For Hawaii

		2015	2016
	total rate	33.91	27.78
	total for all utilities (IOUs, munis, coops, etc.)	33.98	

Average For USA

		2015	2016
	generation	8.83	8.30
	transmission	1.20	1.36
	delivery	5.04	5.46
	ctc	0.19	0.22
	total rate	12.87	12.99
	total for all utilities (IOUs, munis, coops, etc.)	12.62	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

Mid-Atlantic

New Jersey

		12 Months Ending 6/30 2015	2016
Atlantic City Electric Company			
	generation		11.04
	transmission		1.17
	delivery		5.33
	total rate		17.53
Jersey Central Power & Light Company			
	generation	8.76	8.72
	transmission	0.46	0.46
	delivery	3.43	3.38
	ctc	0.31	0.37
	total rate	12.96	12.93
Public Service Electric & Gas Company			
	generation	10.20	10.57
	delivery	3.80	3.72
	ctc	1.42	0.58
	total rate	15.42	14.87
Rockland Electric Company			
	total rate	16.32	14.87
Average For New Jersey			
	generation	9.72	10.11
	transmission	0.46	0.69
	delivery	3.67	3.83
	ctc	1.04	0.51
	total rate	14.65	14.68
total for all utilities (IOUs, munis, coops, etc.)		13.81	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	2016
Pennsylvania			
Duquesne Light Company			
	generation	6.64	6.25
	transmission	1.20	1.10
	delivery	3.75	3.93
	total rate	11.59	11.28
Metropolitan Edison Company			
	generation	7.98	7.77
	delivery	2.59	3.26
	ctc	0.08	0.10
	total rate	10.65	11.13
PECO Energy			
	generation	7.85	7.53
	transmission	0.79	0.58
	delivery	4.20	4.64
	total rate	12.83	12.75
Pennsylvania Electric Company			
	generation	7.56	7.42
	delivery	2.72	3.51
	ctc	0.18	0.22
	total rate	10.46	11.15
Pennsylvania Power Company			
	generation	6.80	8.70
	delivery	2.17	2.55
	total rate	8.97	11.25
Pike County Light & Power Company			
	total rate	17.62	13.69
PPL Utilities Corp.			
	generation	8.13	7.26
	transmission	1.10	1.18
	delivery	2.69	2.87
	total rate	11.92	11.31

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	**2016**
UGI Utilities, Inc.			
	generation	8.30	6.83
	transmission	0.34	0.34
	delivery	3.36	3.33
	total rate	12.00	10.50
West Penn Power Company			
	generation	6.42	7.10
	transmission	0.00	
	delivery	1.68	2.12
	total rate	8.10	9.22
Average For Pennsylvania			
	generation	7.50	7.33
	transmission	0.73	0.87
	delivery	2.76	3.15
	ctc	0.13	0.16
	total rate	11.00	11.17
total for all utilities (IOUs, munis, coops, etc.)		10.24	
Average For Mid-Atlantic			
	generation	8.43	8.62
	transmission	0.66	0.80
	delivery	3.08	3.41
	ctc	0.77	0.40
	total rate	14.25	13.91
total for all utilities (IOUs, munis, coops, etc.)		13.12	

Average Rates
(in cents/kilowatthour)

Total Retail Average Rates

East North Central

Illinois

		12 Months Ending 6/30 2015	2016
Ameren Illinois Rate Zone I (formerly CIPS)			
	delivery	2.22	2.82
Ameren Illinois Rate Zone II (formerly CILCO)			
	delivery	2.47	3.10
Ameren Illinois Rate Zone III (formerly IP)			
	delivery	2.71	3.19
Commonwealth Edison Company			
	generation	6.74	6.21
	delivery	4.29	5.09
	total rate	11.03	11.30
Commonwealth Edison Company - Unbundled			
	delivery	2.79	2.70
MidAmerican Energy			
	total rate	7.40	7.92
MidAmerican Energy Company (Delivery Service)			
	delivery	2.21	2.51
Average For Illinois			
	generation	6.74	6.21
	delivery	2.93	3.25
	total rate	10.69	11.04
total for all utilities (IOUs, munis, coops, etc.)		9.10	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	2016
Indiana			
AEP (Indiana Michigan Power)	total rate	7.97	8.15
Duke Energy Indiana	total rate	9.46	8.64
Indianapolis Power & Light Company	total rate	8.81	9.11
Northern Indiana Public Service Company	total rate	9.44	9.02
Southern Indiana Gas & Electric Company	total rate	10.21	10.29
Average For Indiana	total rate	9.11	8.82
	total for all utilities (IOUs, munis, coops, etc.)	8.94	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30 2015	2016
Michigan			
AEP (Indiana Michigan Power combined MI rate areas)			
	generation	6.95	7.24
	delivery	2.22	2.21
	total rate	9.17	9.45
Consumers Energy			
	total rate	12.19	12.20
DTE Electric Company			
	total rate	10.82	10.99
Northern States Power Company (WI)			
	total rate	10.72	10.76
Upper Peninsula Power Company			
	total rate	14.55	
We Energies (formerly Wisconsin Electric)			
	total rate	13.75	6.97
Wisconsin Public Service Corporation			
	total rate	7.66	8.03
Average For Michigan			
	generation	6.95	7.24
	delivery	2.22	2.21
	total rate	11.37	11.30
total for all utilities (IOUs, munis, coops, etc.)		10.86	

Average Rates
(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	2016
Ohio			
AEP (Columbus Southern Power Rate Area)			
	generation	8.19	6.30
	transmission	1.41	1.36
	delivery	3.70	3.59
	total rate	13.30	11.25
AEP (Ohio Power Rate Area)			
	generation	8.78	6.57
	transmission	1.38	1.32
	delivery	3.00	3.00
	total rate	13.16	10.89
Cleveland Electric Illuminating Company			
	generation	8.06	8.52
	transmission	0.58	0.83
	delivery	2.78	2.63
	ctc		
	total rate	10.91	11.98
Dayton Power & Light Company			
	generation	7.42	6.96
	transmission	0.91	0.61
	delivery	3.71	3.46
	total rate	12.04	11.03
Duke Energy Ohio			
	generation	6.24	6.54
	transmission	0.41	0.46
	delivery	4.40	4.75
	total rate	11.04	11.74
Ohio Edison Company			
	generation	7.27	7.69
	transmission	0.62	0.82
	delivery	2.53	2.52
	ctc		
	total rate	10.33	11.03

Average Rates
(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	**2016**
Toledo Edison Company			
	generation	5.48	5.64
	transmission	0.53	0.76
	delivery	2.01	1.94
	ctc		
	total rate	7.96	8.34
Average For Ohio			
	generation	7.60	6.81
	transmission	0.75	0.97
	delivery	3.03	2.97
	ctc		
	total rate	11.56	10.99
total for all utilities (IOUs, munis, coops, etc.)		9.80	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30 2015	2016
Wisconsin			
Madison Gas & Electric Company	total rate	12.25	12.61
Northern States Power Company (WI)	total rate	10.07	10.25
Northwestern Wisconsin Electric Company	total rate	12.03	11.46
Superior Water, Light & Power Company	total rate	7.29	7.46
We Energies (formerly Wisconsin Electric)	total rate	12.04	11.88
Wisconsin Public Service Corporation	total rate	9.29	9.30
WP&L	total rate	9.90	10.25
Average For Wisconsin	total rate	10.84	10.86
total for all utilities (IOUs, munis, coops, etc.)		10.83	

		2015	2016
Average For East North Central	generation	7.28	6.59
	transmission	0.75	0.97
	delivery	2.97	3.10
	ctc		
	total rate	10.64	10.49
total for all utilities (IOUs, munis, coops, etc.)		9.79	

Average Rates
(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30 2015	2016
Average For West North Central			
	total rate	8.73	9.15
	total for all utilities (IOUs, munis, coops, etc.)	9.18	
South Atlantic			
Delaware			
Delmarva Power			
	generation		8.13
	transmission		0.96
	delivery		2.98
	total rate		12.07
Average For Delaware			
	generation		8.13
	transmission		0.96
	delivery		2.98
	total rate		12.07
	total for all utilities (IOUs, munis, coops, etc.)	11.27	
District of Columbia			
Potomac Electric Power Company			
	generation	8.53	8.53
	transmission	0.54	0.54
	delivery	3.94	3.80
	total rate	13.05	12.87
Average For District of Columbia			
	generation	8.53	8.53
	transmission	0.54	0.54
	delivery	3.94	3.80
	total rate	13.05	12.87
	total for all utilities (IOUs, munis, coops, etc.)	11.94	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	2016
Maryland			
Baltimore Gas & Electric Company			
	generation	7.85	8.38
	transmission	0.77	0.78
	delivery	3.71	3.79
	total rate	12.34	12.94
Delmarva Power			
	generation		6.02
	transmission		0.62
	delivery		6.02
	total rate		12.66
Potomac Edison Company			
	generation	6.51	6.90
	transmission	0.38	0.38
	delivery	2.91	2.91
	total rate	9.80	10.19
Potomac Electric Power Company			
	generation	8.66	8.66
	transmission	0.63	0.63
	delivery	4.18	4.18
	total rate	13.51	13.47
Average For Maryland			
	generation	7.85	8.02
	transmission	0.67	0.67
	delivery	3.74	3.95
	total rate	12.29	12.69
total for all utilities (IOUs, munis, coops, etc.)		12.01	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	**2016**
Virginia			
AEP (Appalachian Power Rate Area)			
	generation	6.94	6.31
	transmission	0.89	1.15
	delivery	1.69	1.73
	total rate	9.52	9.19
Dominion Virginia Power			
	total rate	8.96	8.85
Old Dominion Power Company			
	total rate	9.39	9.40
Average For Virginia			
	generation	6.94	6.31
	transmission	0.89	1.15
	delivery	1.69	1.73
	total rate	9.06	8.91
total for all utilities (IOUs, munis, coops, etc.)		9.44	
West Virginia			
AEP (Appalachian Power Rate Area)			
	total rate	7.98	8.92
AEP (Wheeling Power Rate Area)			
	total rate	6.37	6.71
Monongahela Power Company			
	total rate	7.49	8.39
Potomac Edison Company			
	total rate	8.36	9.06
Average For West Virginia			
	total rate	7.68	8.48
total for all utilities (IOUs, munis, coops, etc.)		7.74	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	**2016**
Average For South Atlantic			
	generation	7.55	7.49
	transmission	0.75	0.84
	delivery	3.36	3.47
	total rate	9.62	9.60
total for all utilities (IOUs, munis, coops, etc.)		10.03	

East South Central

Alabama

		2015	2016
Alabama Power Company			
	total rate	9.33	9.44
Average For Alabama			
	total rate	9.33	9.44
total for all utilities (IOUs, munis, coops, etc.)		9.34	

Kentucky

		2015	2016
AEP (Kentucky Power Rate Area)			
	total rate	8.17	9.35
Duke Energy Kentucky			
	total rate	8.15	7.80
Kentucky Utilities Company			
	total rate	7.93	8.35
Louisville Gas & Electric Company			
	total rate	9.01	9.12
Average For Kentucky			
	total rate	8.30	8.68
total for all utilities (IOUs, munis, coops, etc.)		7.97	

Average Rates

(in cents/kilowatthour)

Total Retail Average Rates

		12 Months Ending 6/30	
		2015	**2016**
Hawaii			
Hawaii			
Hawaii Electric Light Company	total rate	36.31	29.60
Hawaiian Electric Company	total rate	28.01	22.38
Maui Electric Company (Lanai)	total rate	42.19	34.65
Maui Electric Company (Maui)	total rate	33.62	27.65
Maui Electric Company (Molokai)	total rate	40.95	32.40
Average For Hawaii	total rate	29.75	23.95
	total for all utilities (IOUs, munis, coops, etc.)	30.19	
Average For Hawaii	total rate	29.75	23.95
	total for all utilities (IOUs, munis, coops, etc.)	30.19	
Average For USA	generation	8.75	8.04
	transmission	1.14	1.31
	delivery	3.51	3.74
	ctc	0.39	0.28
	total rate	10.76	10.68
	total for all utilities (IOUs, munis, coops, etc.)	10.44	

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 66

Responding Witness: Robert M. Conroy

Q-66. Refer to page 10 of the Conroy Testimony, which states that KU is proposing to increase its residential electric basic service charge in a direction that will more accurately reflect the actual cost of providing service. Explain how the proposed 105 percent increase in the electric residential service charge (from $10.75 to within $1.93 of the $23.93 customer-related cost from the cost-of-service study) can be considered simply moving in the direction of reflecting the fully allocated cost. The explanation should include how the proposed 105 percent increase in the customer charge comports with the ratemaking principle of gradualism referenced on page 7, line 2, of the Conroy Testimony.

A-66. The Company has proposed a rate design that continues to bring both the structure and the charges of the rate design in line with the results of the cost of service study. Directionally that would mean the Basic Service Charge would need to be significantly higher than its current level. The Company has also proposed an energy charge that is separately broken out on the rate schedule into a variable energy charge and an infrastructure charge that reflects fixed costs with both components being derived from the cost of service study.

In addition, KU has sought repeatedly in its recent rate cases to adjust its Basic Service Charges, and indeed all of its rates, to reflect KU's underlying cost of service. But particularly with regard to the residential Basic Service Charge, these attempts have met with resistance, and KU has agreed in settlement negotiations to significantly reduce or eliminate entirely its proposed residential Basic Service Charge increase in each case. Over time, that has led to a large gap between underlying customer-related costs for residential customers and the Basic Service Charge such customers pay. KU is seeking in this case, as it has in past cases, to close that gap and have its rates better reflect underlying costs of service.

But also concerning gradualism, KU respectfully suggests the Commission's orders show that gradualism has traditionally applied not to a single component of rate design for a rate class in isolation, but rather to the overall magnitude of a rate class's proposed rate increase.[1] In this case, KU has proposed to increase the residential Basic Service Charge by $11.25, but that is partially offset by a decrease in the proposed residential energy charge. The resulting proposed net increase for a residential customer with average usage is $7.16 (about 5.9%), which is consistent with gradualism. Given the amount of the proposed increase to the residential class and the small reduction to the energy that would result in the move towards cost of service for the Basic Service Charge, the Company chose to put the increase in the Basic Service Charge.

[1] *See, e.g., Application of Big Sandy Water District for an Adjustment in Rates Pursuant to the Alternative Rate Filing Procedure for Small Utilities*, Case No. 2012-00152, Order at 6 (Mar. 8, 2013) ("Gradualism requires the gradual shifting of costs between customer classes to the class of customer causing the cost."); *Application of Big Sandy Water District for an Adjustment in Rates Pursuant to the Alternative Rate Filing Procedure for Small Utilities, Case No. 2012-00152,* Order at 5 (Mar. 8, 2013); *Adjustment of the Gas arid Electric Rates of the Louisville Gas and Electric Company*, Case No. 10064, Order at 11-12 (Aug. 10, 1988).

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 67

Responding Witness: Robert M. Conroy

Q-67. Refer to the Conroy Testimony, page 19.

a. Refer to lines 4-5. Provide the effect the proposed elimination of the Supplemental/Standby Service Rider will have on the customer taking service under the tariff.

b. Refer to lines 8-11. Explain why KU would have no knowledge of the customer making use of its system.

c. Refer to lines 15-23. Provide the largest rate impact the proposed changes will have on a single customer taking service under any of the affected rate classes (TODS, TODP, RTS, and FLS).

A-67.

a. See the Application Schedule M-2.3, page 10. The proposed elimination of the Supplemental/Standby Service Rider results in a reduction of $111,648 for the customer based on the forecasted test year revenues.

b. The cited testimony does not state that KU "would have no knowledge of the customer making use of its system"; KU meters its service and is aware of customers' usage. Rather, the cited testimony states, "But Rider SS is, by its own terms, a voluntary rider, and it depends upon customers self-reporting their use of the Company as a backup service provider; the Company would rarely, if ever, have independent knowledge of a customer's making such use of the Company's system." In other words, KU cannot know a customer is using KU's system for backup service, as opposed to using KU as the customer's primary (if not sole) power source, unless the customer voluntarily reports it is making such use of KU's system.

c. The largest rate impact the proposed changes will have on a single customer taking service under any of the affected rate classes is 28%. This calculation uses proposed rates, includes only base rate components, and excludes riders for all active KU customers 12-months ending August 2016.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 68

Responding Witness: Robert M. Conroy

Q-68. Refer to the Conroy Testimony, page 20, lines 17-18. Describe the circumstances under which service under the General Service tariff would need to be unmetered.

A-68. The Company proposes to have the ability to bill unmetered usage in those rare circumstances for devices/equipment that are of a consistent load and where metering could cause an undue hardship and/or expense for the customer. The language borrows from the Company's existing TE (traffic energy) rate which authorizes unmetered billing for governmental agencies. As stated in Mr. Conroy's testimony, unmetered installations must be acceptable by both the customer and by the Company. Examples include school and railroad crossings, viaduct lighting, sirens and bus shelters.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 69

Responding Witness: Robert M. Conroy

Q-69. Refer to the Conroy Testimony, page 21, which states that KU intends to offer four new LED lighting options. Also refer to the Seelye Testimony, page 56, which lists five distinct lighting options of 50 watts, 68 watts, 80 watts, 134 watts, and 228 watts. Confirm that KU intends to install five types of LED lights instead of four.

A-69. There will be five different LED wattage options offered under the KU Lighting Service Standard Rate Sheet No. 35.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 70

Responding Witness: Robert M. Conroy

Q-70. Refer to the Conroy Testimony, page 23, lines 5-9. Explain the disadvantages of continuing the current practice of the Cable Television Attachment Charge ("CT AC") tariff applying to cable television system operators and executing license agreements with other entities.

A-70. There are several disadvantages to continuing the present arrangement of negotiating licensing agreements for non-cable television ("CATV") system attachments. First, recently published Commission Staff opinions have created uncertainty as to the continued use of licensing agreements for non-CATV entities and have encouraged telecommunications carriers to negotiate for rates that are no greater than and conditions that are no more stringent than those in the CTAC Rate Schedule. In October 2014, Commission Staff in PSC Staff Opinion 2014-014, Commission Staff stated:

> Commission Staff is unaware of specific evidence sufficient to support a claim that LG&E/KU's [CTAC] tariffs are unreasonable for use in connection with wireless telecommunications attachments. Therefore, with regard to whether or not LG&E/KU may negotiate contracts with the wireless telecommunications providers setting forth rates and conditions for use of pole space in lieu of establishing a rate schedule for such service, Commission Staff concludes that existing tariff provisions of LG&E/KU apply to these attachments and **separate agreements are not necessary.** As discussed, supra, the Commission has determined that the top foot of a pole is "usable space" and should be made available for attachments. In making this determination, the Commission also included the top foot of the pole in establishing the methodology for determining rates for CATV attachments. **Therefore, the per foot current rate that LG&E/KU charge for a CATV attachment would be the appropriate rate to charge for a wireless telecommunications attachment.**

> **Likewise, LG&E/KU tariffs contain provisions applicable to CATV attachments that Commission Staff believes to obviate the necessity of negotiated agreements.**

PSC Staff Opinion 2014-014 (Oct. 23, 2014) at 4 (emphasis added). Similarly, in June 2016, Commission Staff in another published opinion advised a telecommunications carrier "that existing pole attachment tariffs should be sufficient to address costs of wireless carriers' (or other third party) attachments to a utility pole, assuming the attachments are made within the pole space designated for such attachments." PSC Staff Opinion 2016-012 (June 20, 2016). Commission Staff specifically referred to KU's CTAC Rate Schedule.

Second, the lack of a published rate schedule applicable to telecommunication carrier attachments may foster unnecessary negotiations as telecommunications carriers seek to obtain the most favorable rates and conditions of service. With a published rate schedule containing Commission-approved rates and conditions of service, the parties are no longer required to engage in such negotiations. The elimination of such negotiations is likely to reduce the time for an Attachment Customer to begin making attachments to utility structures.

Third, the continuation of the current practice encourages litigation before the Commission. In the absence of an approved rate schedule and conditions of service, potential Attachment Customers who are unable to negotiate a satisfactory license agreement are likely to file a complaint with the Commission to obtain more favorable terms. The existence of an approved rate schedule and conditions of service reduces such action as both the utility and the potential Attachment Customer are fully apprised of what the Commission deems to be reasonable terms.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 71

Responding Witness: Robert M. Conroy

Q-71. Refer to the Conroy Testimony, page 23, line 22, through page 24, line 4. Explain the unique nature and pricing arrangements of the facilities that would not be subject to the proposed Pole and Structure Attachment Charge ("PSA") tariff.

A-71. Three types of telecommunication carrier facilities would not be subject to the PSA Rate Schedule: (1) facilities of incumbent local exchange carriers ("ILEC") with joint use agreements with KU; (2) facilities subject to a fiber exchange agreement with KU; and (3) macro cell facilities. The first two types of facilities involve a transactional arrangement with KU that involves more than the customer obtaining the right to attach its facilities to KU structures. The third type involves a type of facility whose attachment would pose significant operational concerns.

Joint pole usage agreements generally involve agreements between KU and an ILEC for the sharing of poles and other utility structures. Each party to the agreement has constructed its own structures to support its own facilities and has agreed to share the use of its structures with the other party. With joint use agreements, KU is permitted to attach its conductors to an ILEC's poles and an ILEC may attach its communications conductors to KU poles and structures. These agreements reduce the cost to consumers since fewer poles and other structures must be constructed, allow for an equitable sharing of costs between electric and telephone utilities, and minimize the visual impact of two separate networks. Generally the manner in which the cost of the joint use facilities is shared is based upon the number and type of facilities that each party brings to the arrangement as well as the responsibilities that each party has towards the maintenance and upkeep of the joint use structures. Some joint use agreements require a balancing mechanism to compensate the party with the larger number of joint use poles and to encourage the other party to restore parity in numbers. These agreements are dependent upon the unique circumstances of their parties and are not susceptible to a uniform policy set forth in a rate schedule.

In Administrative Case No. 251, the Commission drew a distinction between joint users and those who merely attached their facilities to a utility's structure:

> Considerable argument, and some evidence, was offered on behalf of the CATV operators that they have been treated unfairly by the utilities in not being accorded many of the rights granted each other by the utilities in their joint use arrangements. This issue is resolved by the decision of this Commission to treat CATV operators as customers of the utilities, with concomitant customer rights. CATV operators do not argue that they should be allowed to construct pole line systems of their own to share with the regulated utilities under typical joint use arrangements, and we see no reason why they should. **Since they have no poles to "share," they need not be offered terms equivalent to those in prevailing joint use agreements between utilities both of which own and share poles.**

The Adoption of A Standard Methodology for Establishing Rates for CATV Pole Attachments, Administrative Case No. 251 (Ky.PSC Sept. 17, 1982) at 7 (emphasis added).

Fiber exchange agreements involve agreements between KU and the owners of optical fiber cable in which KU agrees to another party's use of fiber cable that it owns and is attached to its structures in exchange for the use of fiber cable owned by the other party. As with joint use agreements, the agreements involve far more than the right to attach one's facilities or equipment to KU structures. They involve the use of each party's facilities. The agreements are highly dependent upon KU's needs and existing fiber optic cable facilities and the facilities of the other party. They involve a number of different and complex variables. Their provisions are not are not susceptible to a uniform policy set forth in a rate schedule.

Unlike joint use agreements and fiber exchange agreements, macro cell facilities involve the attachment of a telecommunications carrier to a utility structure. A macro cell facility is a wireless communications system site that is typically high-power and high-site, and capable of covering a large physical area, as distinguished from a distributed antenna system, small cell, or WiFi attachment. Macro cell facilities are generally co-located on transmission poles and communications monopoles and towers. Generally, each macro cell facility can be attached only after a structural analysis is performed.

Because macro cell facilities are usually attached only to transmission facilities, they present unique safety and reliability issues not present with wireline pole attachments or wireless facilities. To install or perform maintenance on a macro cell facility generally requires that the transmission circuit be taken out of service. Such action can potentially have adverse system wide consequences. KU does not favor making its transmission towers available for such attachments on an unlimited basis. KU has excluded these attachments from the proposed PSA schedule because such attachments should be rarely made and KU should be afforded maximum discretion in determining when such attachments should be permitted.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 72

Responding Witness: Robert M. Conroy

Q-72. Refer to the Conroy Testimony, page 24, lines 14-17.

a. Provide the rate impact, if any, of the changes to the CTAC tariff on current CT AC tariff customers.

b. Provide the rate impact of the changes to the CT AC tariff on the entities with license agreements.

A-72.

a. KU has not proposed any adjustment to the rate currently contained in the CTAC Rate for wireline pole attachments. While the proposed PSA Rate Schedule permits KU to assess a charge for ducts and for wireless facilities, no current CTAC customer is currently using duct space or attaches a wireless facility to KU structures, except for strand-mounted Wi-Fi access points which do not constitute a separate attachment. Therefore, the proposed revisions are not expected to have any immediate impact.

b. Under the provisions of the proposed PSA Rate Schedule, an entity currently taking making attachments to KU structures pursuant to a licensing agreement will not be subject to the proposed charges in the PSA Rate Schedule until its licensing agreement with KU has expired. The proposed charges will therefore have no immediate effect on existing licensees. As discussed in the testimony of Mr. Seelye, for purposes of calculating the impact on miscellaneous revenues in this proceeding, the Company assumed that all wireline contracts will expire during the test year, resulting in an increase in miscellaneous revenue of $19,720.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 73

Responding Witness: Robert M. Conroy

Q-73. Refer to the Conroy Testimony, page 25.

a. Refer to lines 11-12. Explain the reason for proposing a ten-year term of service.

b. Refer to lines 16-24. Assuming the proposal to eliminate the Meter Data Processing Charge is approved, confirm that KU will continue to provide the paper reports until the customer is able to access the information through KU's website. If this cannot be confirmed, explain.

A-73.

a. The proposed PSA Rate Schedule will be applicable to CATV systems and to telecommunications carriers. Previously the telecommunications carriers attached to Company structures pursuant to a license agreement. The term of those license agreements was generally ten years. KU revised the period to 10 years to reflect its longstanding practice with telecommunications carriers and considers it a reasonable length for an initial term of service.

b. Yes, KU will continue to provide paper reports until the customer is able to obtain the information in electronic format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 74

Responding Witness: Robert M. Conroy

Q-74. Refer to the Conroy Testimony, pages 26-27 which discuss new proposed charges for customers reconnecting service without authorization.

a. Confirm that KU's tariff currently allows it to collect from a customer all expenses for damage caused due to an unauthorized reconnection.

b. Assuming the proposed charges are approved, explain if KU will be able to recover amounts in excess of the proposed charges, should a higher amount of damage occur.

A-74.

a. Confirmed. KU's "Protection of Company's Property" provision (at Sheet No. 97.1) and paragraph I of KU's "Discontinuance of Service" provision (at Sheet Nos. 105.1 – 105.2) both allow KU to collect costs from customers who cause damage to KU's property due to an unauthorized reconnection.

b. Yes, KU's position is that the above-cited tariff provisions will continue to allow KU to recover amounts in excess of the proposed unauthorized reconnection charges if a higher amount of damage occurs.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 75

Responding Witness: Robert M. Conroy

Q-75. Refer to the Conroy Testimony, pages 26-27. Explain the circumstances giving rise to the proposed change in the Existing Base Load calculation for the Economic Development Rider. State whether KU has experienced problems such as those discussed on page 27 regarding use of the three-year average.

A-75. The proposed change will follow the Companies' business practice and ensure consistency across all customers. KU has not experienced any problems with calculating the three-year average, but believes the 12-month rolling average accurately reflects the customer's current level of demand.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 76

Responding Witness: Christopher M. Garrett

Q-76. Refer to the Conroy Testimony, page 27, line 21, through page 28, line 3. Assuming approval of KU's Application as filed, provide the effect it would have on the Solar Capacity Charge and Solar Energy Credit.

A-76. KU did not propose any change to the Solar Capacity Charge and Solar Energy Credit in its Application as filed given the timing of the Application and the associated Order from the Commission.

Assuming approval of KU's Application as filed in this proceeding, and assuming the Commission permits the Company to update the Solar Energy Credit, the Company proposes that the Solar Energy Credit for each rate schedule, based on the cost of service study as filed, be as shown in the table below.

RATE SCHEDULE	RATE	KU
Residential Volunteer Fire Department Residential Time-of-Day Energy Residential Time-of-Day Demand	RS VFD RTOD-E RTOD-D	$0.03508
All Electric Schools (KU Only)	AES	$0.03523
General Service	GS	$0.03508
Power Service Secondary	PS	$0.03572
Power Service Primary	PS	$0.03472
Time-of-Day Secondary Service	TODS	$0.03531
Time-of-Day Primary Service	TODP	$0.03433

Because the Solar Capacity Charge was approved recently, the Company proposes that the Solar Capacity Charge approved by the Commission in Case No. 2016-00274 remain in effect until the Company's next rate case.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 77

Responding Witness: Robert M. Conroy

Q-77. Refer to the Conroy Testimony, pages 31-32. Explain the circumstances giving rise to the proposed text change to the Contracted Demands provision at Sheet No. 97, and whether KU has experienced a situation such as that discussed on page 32, lines 5-8.

A-77. KU is unaware of any customer's business circumstances that leads to stopping the service entirely at a location only to reestablish service at the same location in a short period of time. KU has experienced these situations as described in the testimony and proposed the provision in Sheet No. 97 to establish a process to address such situations.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 78

Responding Witness: William S. Seelye

Q-78. Refer to the Seelye Testimony, page 2, lines 7-10.

a. State whether KU is aware of the Commission's approving a Loss of Load Probability Cost of Service Study ("LOLP COSS") in another proceeding. If so, provide the case number of the proceeding.

b. State whether KU is aware of a LOLP COSS's having been approved in other state jurisdictions. If so, provide the state and docket number.

A-78.

a. The Company is unaware of the Commission's ever having approved a LOLP COSS in another proceeding.

b. The Company is unaware of a LOLP COSS being approved in another state jurisdiction. The Company is introducing the LOLP COSS *as an alternative* because an LOLP allocator is consistent with the way that generation resources have been planned for several decades.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 79

Responding Witness: John P. Malloy / William S. Seelye

Q-79. Refer to the Seelye Testimony, page 4, lines 5-9.

a. By rate class, provide the number of customers that have installed distributed generation.

b. Mr. Seelye states on page 15, line 1 0, of his testimony that distributed generation has not yet created a significant problem for KU. Explain how a movement towards a rate design that more accurately reflects the actual cost of providing service is necessary as opposed to a gradual movement to coincide with a gradual increase in distributed generation.

A-79.

a. The Company has identified the following number of customers by rate class with distributed generation (which includes net metering customers):

Rate Class	**Number of Customers**
General Service Single Phase	16
General Service Three Phase	11
Power Service Secondary	4
Residential Service	118
Time of Day Primary	2
Time of Day Secondary	1
Total	**152**

b. For many year, it has been the Company's objective to move its rate design to more accurately reflect the actual cost of providing service. In this proceeding, the Company is proposing to take incremental steps toward gradually achieving that objective. *It must be emphasized that the Company is not proposing to modify its rates to fully reflect cost of service in this proceeding.* For example, the Company is not proposing in this proceeding to replace its two-part rates for Residential Rates RS and General Service GS with multi-part rates, even though a multi-part rate would more accurately reflect the actual cost of providing service and even though multi-part rates have been used for large power customers for decades. In this proceeding, the Company is taking the initial steps of (i) changing the *presentation* of the charges for Rates RS and GS to break out the variable cost component of the energy charge (Variable Energy Charge) and the fixed component of the energy charge (Infrastructure Energy Charge) and (ii) changing the demand structure of its large power rates (TOD-S, TOD-P, RTS, and FLS) to more accurately reflect cost of service. However, it should be pointed out that Rates TOD-S, TOD-P, RTS, and FLS are currently structured as multi-part rates; therefore, the changes being proposed to these rates should still be considered a "gradual movement" that has been taking place over many years. Therefore, it is the Company's position that the rate changes being proposed in this proceeding do reflect a gradual movement toward cost-based rates.

It is also important to consider the disadvantages of gradual rate changes as it pertains to distributed generation. A rate design that is not cost based, one that improperly recovers fixed costs through variable charges, sends a false economic to anyone who would install distributed generation because the customer's avoided cost for installing a generator would be higher than it would be under a cost based rate. A false economic signal might incent someone to install distributed generation, when under a cost based rate, they would not. It is therefore important to send accurate price signals so that customers do not invest in distributed generation under a false set of price signals, only to see circumstances change as rates move toward true cost. This is a problem that regulatory commissions are struggling with in other jurisdictions.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 80

Responding Witness: William S. Seelye

Q-80. Refer to the Seelye Testimony, page 7. Provide Table 1 with an additional column representing the rate of return on rate base assuming the proposed revenue increase is approved.

A-80.

	Rate of Return on Rate Base at Current Rates		Revenue	Rate of Return on Rate Base at Proposed Rates	
Rate Class	BIP Version	LOLP Version	Increase	BIP Version	LOLP Version
Residential Service	4.16%	4.36%	5.94%	5.64%	5.85%
General Service	9.10%	9.20%	5.06%	10.95%	11.05%
All Electric Schools	5.27%	6.77%	5.34%	7.07%	8.75%
Primary Service-Secondary	9.61%	9.26%	5.06%	11.51%	11.12%
Primary Service-Primary	11.83%	10.70%	4.71%	13.77%	12.55%
Time-of-Day Secondary Service	6.42%	6.06%	5.55%	8.30%	7.91%
Time-of-Day Primary Service	4.48%	4.05%	6.61%	6.57%	6.10%
Retail Transmission Service	4.55%	4.50%	6.71%	6.76%	6.72%
Fluctuating Load Service	1.50%	1.24%	7.25%	3.44%	3.14%
Lighting Energy Service	9.83%	18.57%	0.00%	9.82%	18.56%
Traffic Energy Service	10.02%	11.34%	4.71%	11.66%	13.11%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	6.14%	8.83%	9.66%
Total All Classes	5.56%	5.56%	6.45%	7.29%	7.29%

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 81

Responding Witness: William S. Seelye

Q-81. Refer to the Seelye Testimony, page 13, line 7, through page 14 line 4. Provide a list of other utilities whose residential tariffs include a three- or multi-part rate design.

A-81. While Mr. Seelye has not compiled an exhaustive list of utilities that have implemented three- or multi-part rate designs for residential customers, we are aware of a number of utilities that have recently adopted such rate designs. We are also aware of many others that are currently evaluating three- and multi-part rate designs. Listed below are utilities we are aware of that have implemented three- or multi-part rates with residential demand charges.

Mid Carolina Electric Cooperative ("Mid Carolina") in South Carolina recently implemented a three-part rate consisting of a customer charge, energy charge and demand charge for all residential customers. Mid Carolina's rate consists of a customer charge of approximately $24.30 (billed at a rate of 80 cents per day), an energy charge of $0.047/kWh, and a demand charge applied during the on-peak period of $12/kW.

Cobb Electric Membership Corporation ("Cobb") in Georgia has recently introduced residential demand rates. With approximately 200,000 customers, Cobb is one of the largest electric cooperatives in the United States. Beginning in 2016, all new residential customers are placed on a multi-part rate consisting of a demand charge. Cobb has indicated that it intends to transition all residential customers to its demand rate by December 31, 2018.

In Kentucky, the municipal electric utility serving the city of Glasgow, Kentucky has implemented a multi-part rate with a cost-based demand charge for all residential customers.

All three of these utilities have implemented Advanced Metering Systems ("AMS").

A number of investor owned utilities have also introduced optional multi-part rates consisting of customer, demand, and energy charges, including Alabama Power

Company, Alaska Electric Light & Power, Arizona Public Service Company, Black Hills Power Company, Virginia Electric and Power Company, Duke Energy Company, Georgia Power Company, Westar Energy Company, and Public Service Company of Colorado.

Mr. Seelye has also personally had conversations with numerous other electric utilities about their plans to evaluate the implementation of multi-part rates for all customers, including residential customers.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 82

Responding Witness: Robert M. Conroy

Q-82. Refer to the Seelye Testimony, page 14, line 21, through page 15, line 8. Explain whether KU has considered proposing a new tariff specific to customers with distributed generation, such as solar panels or wind turbines, in order to address the issues discussed in Mr. Seelye's testimony, as opposed to increasing the customer charge for all customers within a rate class.

A-82. Kentucky's Net Metering Statutes (KRS 278.465 *et seq.*), and in particular KRS 278.466(4), prohibit utilities from treating net metering customers, i.e., customers with eligible electric generating facilities such as solar panels or wind turbines, differently than similarly situated non-net-metering customers. Therefore, it would not be permissible under current Kentucky law for KU to propose a tariff for net metering customers that had a different Basic Service Charge than would apply to similarly-situated non-net-metering customers.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 83

Responding Witness: William S. Seelye

Q-83. Refer to the Seelye Testimony, page 22, lines 12-13. Explain why interclass subsidies are minimally addressed in the proposed rate design.

A-83. The Companies capped the maximum increase for any major rate class at 10 percent. Addressing inter-class subsidies for any major rate class would have necessitated increasing the rate classes with low rates of return, particularly LG&E's Residential Rate RS and KU's Fluctuating Load Service Rate FLS by more than 10 percent. The Companies had to balance reducing inter-class subsidies with the level of the increase each class would receive. In these proceedings, the Companies concluded that limiting the increase to any class at 10% was reasonable. However, this decision limited the amount of subsidy reduction that could be accomplished.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 84

Responding Witness: Robert M. Conroy / William S. Seelye

Q-84. Refer to the Seelye Testimony, pages 32-37.

a. On page 34, lines 6-7 state that without a ratchet, Customer A would be overpaying. Tables 6 and 7 show the demand charge revenue without a ratchet and with a ratchet, respectively. The amount paid by Customer A is the same in both tables. State whether this indicates that Customer A overpays with or without a ratchet.

b. Beginning at the bottom of page 36, line 15, Mr. Seelye states, "Some low-load factor customers will have a maximum demand that coincides with the system peak and others may not."

   1. Explain the extent to which KU has given consideration to making changes to the tariffs with demand ratchets so that customers whose peak demand does not coincide with the system peak do not pay ratchet demand rates or pay a reduced ratchet percentage.

   2. What consideration has KU given to offering a Power Service Time-of-Day tariff? Explain the advantages and disadvantages of offering such a tariff.

c. State whether all General Service customers currently have meters that measure demand. If not, explain how KU determines whether a customer's 12-month-average monthly maximum load is 50 kW or less, qualifying the customer for the rate schedule.

d. Refer to page 36, lines 12-15.

   1. State whether this section indicates that KU would incur less costs if Customer B had the same load as Customer A.

   2. State whether there is no benefit to KU when Customer B has a lower load in some month

A-84.

a. In the example, Customer A overpays in each scenario because the example is designed to illustrate problems associated with not applying a ratchet. In practice, the additional revenue from customers whose demands are ratcheted would have the effect of lowering the demand charge to all customers in the class. Customer A would see a benefit based on the effect the additional revenue would have on the level of the demand charge. However, in the example, Customer A's demand charges would not fully reflect cost except with a 100% ratchet. The example does not account for the revenue impact on the demand charge. It simply illustrates how the ratchet ensures that Customer B would pay the same as customer A under a 100% ratchet, and that under a 50% ratchet Customer B also pays more of its fair share of costs than under no ratchet at all. The purpose of the discussion was to demonstrate that ratchets can improve equity between customers with respect to monthly load fluctuations and that, in the example, the only way to ensure that Customer A does not overpay would be to apply a 100% ratchet.

b.

1. The Company is currently exploring ways to modify Power Service Rate PS so that the rate structure more accurately reflects cost of service. This would likely involve adopting a multi-part TOD rate design similar to Rates TODS, TODP, and RTS. The reason that the Company has not implemented multi-part rates for Rate PS in the past is because the metering cost involved with billing customers under a multi-part rate *using traditional metering technologies* would have almost certainly been cost prohibitive. LG&E serves approximately 2,800 customers under Rate PS and KU serves approximately 4,500 customers under Rate PS. In the past, replacing Rate PS meters with interval demand meters based on traditional metering technologies would have been an extremely costly undertaking. With an Automatic Metering System ("AMS") in place that uses modern electronic technologies, which will also provide other operational benefits, implementing multi-part rates for Rate PS and other standard service schedules will be something that the Company intends to evaluate.

2. See above response. With a multi-part TOD rate design similar to Rates TOD, TODP, and RTS, customers that can shift their loads to off-peak periods can realize savings in their demand billings while concurrently reducing generation fixed costs incurred by the Company. TOD rate designs more accurately reflect the cost of providing service to customers. In the past, the Company has limited multi-part rates such as Rates TOD, TODP, and RTS because of the high cost of installing metering equipment that utilized traditional metering and communication technologies. Because of the high cost of implementing TOD demand rates, in Administrative Case No. 203 investigating the implementation of the TOD ratemaking standard under the Public Utilities Regulatory Policy Act ("PURPA"), the Commission originally allowed LG&E and KU to limit

demand metered TOD rates to only the very largest customers on their systems. Over time, the Companies reduced this demand level to its current level of 1,000 kW. With the implementation of AMS, multi-part TOD rates can be considered for implementation to a broader base of customers.

c. No. Currently, General Service Rate GS customers typically do not have meters that measure demands. However, under the Company's proposed AMS program the new metering technology would have the capability to measure demands. The 12-month average monthly load threshold of 50 kW currently set forth in Rate GS is validated on the basis of the customer's maximum installed capacity when the customer signs up for service or on the basis of previous installed capacity or loads for customers signing up for service at pre-existing premises. The Company also performs an annual validation process to flag customers whose annual kWh usage is sufficiently high to indicate that they may exceed the 50 kW threshold under Rate GS, in which case the Company will perform additional analysis and, if warranted, install a test meter to measure the customer's demands.

d.

1. No. Table 5 shows that even though Company would incur the same fixed costs to service both Customer A and Customer B, *without a demand ratchet* Customer B pays less than Customer A despite the same costs that are incurred to serve both customers. Table 7 shows that with a 100% demand ratchet, Customer A and Customer B would pay the same demand charges. The loads for Table 7 are the same as for Table 5. The difference between the two tables is that there is no demand ratchet used for Table 5 but a 100% demand ratchet for Table 7. If the loads were the same for Customer A and Customer B, then the two customers would pay the same regardless of the ratchet. The point of the example does not relate to the cost incurred by KU, but which customers pay those costs. The Company's total demand revenues would be the same regardless of the level of the ratchet. In the example, having a ratchet improves the equity of the rate design because it requires Customer B to pay more of its fair share of the cost.

2. The analysis is an idealized example designed to demonstrate the importance of demand ratchets in designing rates to accurately reflect cost of service. However, there are no benefit to the Company in terms of fixed costs for a customer such as Customer B to have lower demands during off-peak months.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 85

Responding Witness: William S. Seelye

Q-85. Refer to the Seelye Testimony, page 44, lines 9- 13. Mr. Seelye provides an example that if a customer has installed solar generation, then KU would be called upon to provide backup power when there is not sufficient sunlight to power the solar panels. Mr. Seelye states that this is likely to occur during KU's peak periods, such as during a winter system peak, which usually occurs during nighttime hours. State whether customers with solar generation are less likely to need backup power during the summer peak.

A-85. On page 44, lines 9-13 of his testimony, Mr. Seelye was simply referring to the fact that a customer's solar panels would likely not be generating significant amounts of power during the Company's winter system peak, which often occurs during nighttime hours. This in no way suggests that customers with solar panels would have no need for back-up power during summer peak periods. The need for backup power during summer peak periods would depend on other factors, such as whether the peak occurs during evening hours when sunlight is diminishing or whether the summer peak occurs when there is a significant cloud cover preventing the full utilization of the solar panels. It is likely that customers with solar panels would need backup power during both winter and summer peak periods. During winter peaks, it is a virtual certainty that the solar panels won't be operating at the time of the system peak.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 86

Responding Witness: William S. Seelye

Q-86. Refer to the Seelye Testimony, page 46, lines 6-20.

a. For a hypothetical customer with distributed generation taking service under each of the rate schedules TODS, TODP, RTS, and FLS, state the amount the customer would be billed if it uses KU power during only one month of the year. Include in the response a breakdown of the billing components.

b. For a hypothetical customer with distributed generation taking service under each of the rate schedules TODS, TODP, RTS, and FLS, state the amount the customer would be billed if it does not use KU power during any month of the year. Include in the response a breakdown of the billing components.

A-86. The annual billing amount for a customer with distributed generation that uses KU power only one month of the year depends on whether the customer uses KU power during the peak, intermediate or off-peak period. Rates TODS, TODP, and RTS are time-of-day demand rates and the annual billing would be different depending on periods during the days during which the customer needs back-up demand. Therefore, two calculations will be provided. The first calculation (Calculation A) will be for a customer that requires demand and energy during the peak period for one month during the year, and the second calculation (Calculation B) will be for a customer that requires demand and energy during the off-peak period for one month during the year.

Calculation A

Assumptions: The customer's maximum demand of 2,000 kW occurs during the peak period. The customer's energy usage for the month in which KU power is required is 74,400 kWh, which assumes a 5% load factor based on a 31-day month (31 days x 24 hrs x 2,000 kW x 5%). The customer's demand occurs during the peak period. All rate adjustment clauses such as Fuel Adjustment Cause, Off-System Sales Adjustment Clause, etc. are not included.

Under KU's proposed TODP, the customer's annual billing for the current and subsequent 11 months would be:

Basic Service Charges	
[$330 x 12 months]	$ 3,960.00
Peak Demand Charge	
[(2,000 kW + 2,000 kW x 50% x 11) x $6.83/kW]	$ 88,790.00
Intermediate Demand Charge	
[(2,000 kW + 2,000 kW x 50% x 11) x $5.34/kW]	$ 69,420.00
Basic Demand Charge	
[(2,000 kW x 12) x $2.92/kW]	$ 70,080.00
Energy Charge	
[74,400 kWh x $0.03433/kWh]	$ 2,554.15
Total	**$ 234,804.15**

Calculation B

Assumptions: The customer's maximum demand of 2,000 kW occurs during the off-peak period. Again, the customer's energy usage for the month in which KU power is required is 74,400 kWh, which assumes a 5% load factor based on a 31-day month (31 days x 24 hrs x 2,000 kW x 5%). The customer's demand occurs during the off-peak period. Rate adjustment clauses such as Fuel Adjustment Cause, Off-System Sales Adjustment Clause, etc. are not included.

Under KU's proposed TODP, the customer's annual billing for the current and subsequent 11 months would be:

Basic Service Charges [$330 x 12 months]	$ 3,960.00
Peak Demand Charge	
[(0 kW + 0 kW x 50% x 11) x $6.83/kW]	$ 0.00
Intermediate Demand Charge	
[(0 kW + 0 kW x 50% x 11) x $5.34/kW]	$ 0.00
Basic Demand Charge	
[(2,000 kW x 12) x $2.92/kW]	$ 70,080.00
Energy Charge	
[74,400 kWh x $0.03433/kWh]	$ 2,554.15
Total	**$ 76,594.15**

b. For a customer with distributed generation that does not use KU power during any month of the year, the customer would need to contract 2,000 kW of demand to receive backup power and the Basic Demand Charge would be applied. Therefore, the annual billing under Rate TODP would be as follows:

Basic Service Charges	
[$330 x 12 months]	$ 3,960.00
Peak Demand Charge	
[(0 kW + 0 kW x 50% x 11) x $6.83/kW]	$ 0.00
Intermediate Demand Charge	
[(0 kW + 0 kW x 50% x 11) x $5.34/kW]	$ 0.00
Basic Demand Charge	
[(2,000 kW x 12) x $2.92/kW]	$ 70,080.00
Energy Charge	
[0 kWh x $0.03433/kWh]	$ 0.00
Total	**$ 74,040.00**

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 87

Responding Witness: William S. Seelye

Q-87. Refer to the Seelye Testimony, page 49, lines 8-16.

a. State whether KU expects that the customer bill increases and decreases due to the proposed change to the Base Demand Charge demand ratchet will net to, or near, zero.

b. Provide the largest effect the proposed change to the Base Demand Charge demand ratchet will have on a single customer in each affected rate class.

A-87.

a. Yes. Based on test year-year billing determinants, the customer bill increases and decreases due to the proposed change to the Base Demand Charge demand ratchet are designed to net to zero. For the billing determinants for Rates TODS, TODP, RTS, and FLS shown in Schedule M-2.3, the current Base Demand Charge is applied to billing demands with the current ratchet and the proposed Base Demand Charge is applied to billing demands with the proposed ratchet.

b. The largest percentage increase that the proposed demand ratchet will have on any single customer:

FLS:	0.3%
RTS:	9.4%
TODP:	28.0%
TODS:	22.5%

This calculation uses proposed rates, includes only base rate components, and excludes riders for all active KU customers for the 12 months ended August 2016.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 88

Responding Witness: William S. Seelye / David S. Sinclair

Q-88. Refer to the Seelye Testimony, page 52, lines 10-14. State whether KU owns any CTs that are not considered "large-frame" CTs. If so, provide the following:

a. The name of each CT.

b. The location of each CT in the dispatch order.

c. The number of hours each CT operated in 2015 and 2016.

d. The amount of CSR credits that would result if the calculation used the CTs that are highest in the dispatch order (regardless of whether they qualify as large-frame).

A-88.

a. KU's secondary CTs – Haefling 1 and 2 – are not considered "large-frame."

b. The Companies' dispatch order as of January 2017 is provided in the table below. All of the secondary CTs are last in the dispatch order.

Dispatch Order (Lowest Cost to Highest Cost)	**Unit**
1	Brown Solar
2	Hydro (Ohio Falls and Dix Dam)
3	Trimble County 2
4	Mill Creek 4
5	Mill Creek 3
6	Ghent 2
7	Mill Creek 2
8	Ghent 1
9	Mill Creek 1
10	Trimble County 1
11	Ghent 4

Dispatch Order (Lowest Cost to Highest Cost)	Unit
12	Cane Run 7
13	Ghent 3
14	OVEC
15	Brown 2
16	Brown 1
17	Brown 3
18	Trimble County 5
19	Trimble County 6
20	Trimble County 7
21	Trimble County 8
22	Trimble County 9
23	Trimble County 10
24	Paddy's Run 13
25	Bluegrass
26	Brown 9
27	Brown 10
28	Brown 5
29	Brown 8
30	Brown 11
31	Brown 6
32	Brown 7
33	Cane Run 11
34	Paddy's Run 11
35	Paddy's Run 12
36	Zorn 1
37	Haefling

c. KU's secondary CTs' 2015 and 2016 service hours are shown in the table below.

	2015 Service Hours	2016 Service Hours
Haefling 1	113	14
Haefling 2	117	12

d. The company has not performed the requested analysis and did not have sufficient time to prepare the analysis. For KU, the proposed CSR credits were determined based on the following large-frame CTs ("Primary CTs") owned or jointly owned by KU: Brown 5, Brown 6, Brown 7, Brown 8, Brown 9, Brown 10, Trimble 5, Trimble 6, Trimble 7, Trimble 8, Trimble 9, Trimble 10, and Paddy's Run 13. The CSR credits were determined based on the fixed costs of these Primary CTs because they are among the units with the highest operating costs in the Company's fleet, other than the CTs that are operated primarily for testing or for emergencies. The only non-large-frame ("Secondary CTs") owned by KU are the Haefling units, which have a combined net demonstrated capacity of 24 MW. Because of the high operating costs of these units, they are rarely operated. During the 12 months ended June 30, 2016, the Haefling units only operated 15 hours. During this 12 month period, almost all of the unit start-ups were for unit testing. Because of the high energy cost of operating the Secondary CTs, the limited number of hours of operation, and the age of the units, the Company does not believe that it is appropriate to calculate the CSR credits based on the fixed costs of these units.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 89

Responding Witness: Robert M. Conroy / William S. Seelye

Q-89. Refer to the Seelye Testimony, page 55, lines 19-21. These lines state that mercury vapor and incandescent lights are no longer being replaced . Explain whether this statement means that the bulbs are not being replaced , or whether the fixtures are not being replaced.

A-89. As stated in Question No. 6, the Company does not want to encourage future customers to be on lighting rates that lack product availability or utilize an older technologies. Therefore, any failure of an incandescent fixture or bulb results in the entire incandescent fixture being removed.

The Company replaces failed mercury vapor bulbs; however, the Company removes the entire mercury vapor fixture if parts (other than the bulb) fail.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 90

Responding Witness: William S. Seelye

Q-90. Refer to the Seelye Testimony, page 56, lines 16-20. Explain why the average service life of a light emitting diode fixture is expected to be lower than other lights.

A-90. The Company's lighting vendors have indicated to the Company that the average service life of an LED fixture is lower than conventional fixtures. The reason that they have given is that while LED fixtures have long lives in laboratory conditions, temperature fluctuations in the field shorten the lives of the fixtures.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 91

Responding Witness: Robert M. Conroy

Q-91. Refer to the Seelye Testimony, page 59, lines 4-15.

a. State whether entities currently being charged only the annual pole attachment charge of $7.25 could also be charged the proposed additional new charges if approved by the Commission. If so, explain.

b. State whether new attachments by entities with an existing contract will be charged the proposed PSA rates for the new attachment or at the contract rates.

A-91.

a. If the Commission approves the proposed PSA Rate Schedule and an CATV system that currently attaches to KU's structures uses the KU's ducts or attaches a wireless facility to KU's structures, it will be assessed the proposed PSA Rate Schedule charge for such use or attachment. The CTAC Rate Schedule, which applies only to CATV system operators attaching wirelines to KU's poles, does not provide for any charge for use of KU ducts or the attachment of wireless facilities to KU structures. No CATV system operator currently uses KU's ducts or attaches a wireless facility to KU's structures, except for strand-mounted Wi-Fi access points which do not constitute separate attachments.

b. KU assumes that the reference to "entities with an existing contract" refers to telecommunication carriers that currently attach to the Company's structures under the terms of a license agreement. The proposed PSA Rate Schedule charges will not apply to existing or new attachments of a telecommunications carrier so long as the carrier's license agreement is in effect. KU will continue to assess the charges set forth in the license agreement for existing and new attachments until the expiration of the license agreement. Upon the expiration of the license agreement, KU will assess the telecommunications carrier the PSA Rate Schedule charges for all attachments.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 92

Responding Witness: William S. Seelye

Q-92. Refer to the Seelye Testimony, page 60, line 20, through page 61, line 1. Provide a copy of the Federal Communication Commission Report and Order referenced in the testimony.

A-92. See attached.

Before the
Federal Communications Commission
Washington, D.C. 20554

In the Matter of	)	
	)	CS Docket No. 97-98
Amendment of Rules and Policies	)	
Governing Pole Attachments	)	

REPORT AND ORDER

Adopted: March 29, 2000 Released: April 3, 2000

By the Commission:

TABLE OF CONTENTS

I. INTRODUCTION

1. This *Report and Order* ("*Order*") addresses issues raised in *Amendment of Rules and Policies Governing Pole Attachments*, *Notice of Proposed Rulemaking*, CS Docket No. 97-98 ("*Notice*")[1] relating to the maximum just and reasonable rates utilities[2] may charge for "pole attachments"[3] made to a pole, duct, conduit or right-of-way.[4] Generally, the commenters[5] represent the interests of one of the following three categories: (1) electric utilities;[6] (2) cable operators;[7] and (3) telecommunications carriers.[8] In this *Order*, we adopt amended rules set forth in Appendix A.

II. BACKGROUND

2. Section 224 of the Communications Act ("Pole Attachment Act")[9] grants the Commission authority to regulate the rates, terms, and conditions[10] governing pole attachments and requires that such

[1] 12 FCC Rcd 7449 (1997).

[2] A "utility" is defined as any person who is a local exchange carrier or an electric, gas, water, steam, or other public utility, and who owns or controls poles, ducts, conduits, or rights-of-way used, in whole or in part, for any wire communications. Such term does not include any railroad, any person who is cooperatively organized, or any person owned by the Federal Government or any State. 47 U.S.C. § 224(a)1).

[3] The term "pole attachment" is defined as any attachment by a cable television system or provider of telecommunications service to a pole, duct, conduit, or right-of-way owned or controlled by a utility. 47 U.S.C. § 224(a)(4).

[4] 47 U.S.C. § 224; 47 C.F.R. §§ 1.1401-1.1416.

[5] A list of commenters, as well as the abbreviations used in this *Order* to refer to such parties, is contained in Appendix B hereto.

[6] Commenting electric utilities generally include American Electric, Carolina Power, Chugach, ConEd, Duquesne Light, Edison Electric/UTC, Ohio Edison, Public Service of New Mexico, Southeastern Indiana REMC, and Union Electric.

[7] Commenting cable operator interests generally include NCTA, SCBA, TCI, Time Warner, and WorldCom.

[8] Commenting telecommunications carrier interests generally include Ameritech, Association of Local Telecommunications Services, AT&T, Bell Atlantic/NYNEX, BellSouth, GTE, KMC Telecom, MCI, Qwest, SBC, SNET, Sprint, USTA, and U S West. Some telecommunications carriers are local exchange carriers who are also pole owners.

[9] Communications Act of 1934, *as amended* by Pub. L. No. 95-234, 47 U.S.C. § 224.

[10] 47 U.S.C. § 224.

rates, terms and conditions be just and reasonable.[11] The Commission is also authorized to adopt procedures necessary to hear and to resolve complaints concerning such rates, terms, and conditions.[12] In 1978, when Congress directed the Commission to regulate rates for pole attachments used for the provision of cable service, Congress established a zone of reasonableness for such rates, bounded on the lower end by incremental costs[13] and on the upper end by fully allocated costs.[14] *See* S. Rep. No. 95-580 ("*1977 Senate Report*").[15]

3. Beginning in 1978, the Commission developed a methodology to determine the maximum allowable pole attachment rate under Section 224(d)(1), (the "*Cable Formula*"),[16] in *Adoption of Rules for the Regulation of Cable Television Pole Attachments, First Report and Order*, CC Docket No. 78-144 ("*First Report and Order*");[17] *Second Report and Order* ("*Second Report and Order*");[18] and *Memorandum and Order* ("*Third Order*"),[19] implementing a cost methodology premised on historical or embedded costs.[20] In 1987, the Commission amended and clarified the methodology for determining rates in *Amendment of Rules and Policies Governing the Attachment of Cable Television Hardware to Utility*

---

[11]The Commission's authority does not extend to pole attachment rates, terms, and conditions that a state regulates. 47 U.S.C. § 224(c)(1). Jurisdiction for pole attachments reverts to the Commission generally if the state has not issued and made effective rules implementing the state's regulatory authority over pole attachments. Reversion to the Commission, with respect to individual matters, also occurs if the state does not take final action on a complaint within 180 days after its filing with the state, or within the applicable period prescribed for such final action in the state's rules, as long as that prescribed period does not extend more than 360 days beyond the complaint's filing. 47 U.S.C. § 224(c)(3).

[12]47 U.S.C. § 224(b)(1).

[13]*See* 47 U.S.C. § 224(d)(1). In the pole attachment context, incremental costs are those costs that the utility would not have incurred "but for" the pole attachments in question.

[14]*Id.* Fully allocated costs refer to the portion of operating expenses and capital costs that a utility incurs in owning and maintaining poles that are associated with the space occupied by pole attachments.

[15]S. Rep. No. 95-580, 95th Cong., 1st Sess. 19 (1977).

[16]47 C.F.R. § 1.1404.

[17]68 FCC 2d 1585 (1978).

[18]72 FCC 2d 59 (1979).

[19]77 FCC 2d 187 (1980), *aff'd*, *Monongahela Power Co. v. FCC*, 655 F.2d 1254 (D.C. Cir. 1985) (per curiam).

[20]72 FCC 2d at 66, ¶ 15. Historical costs are costs that a firm has incurred in the past for providing a good or service and are recorded for accounting purposes as past operating expenses and depreciation.

Poles, CC Docket No. 86-212 ("*Pole Attachment Order")*.[21]

4. The Telecommunications Act of 1996 ("1996 Act")[22] amended Section 224 in several important respects. Section 703(6) of the 1996 Act added a new Subsection 224(d)(3),[23] that expanded the scope of Section 224 by applying the *Cable Formula* to rates for pole attachments made by telecommunications carriers[24] in addition to cable systems,[25] until a separate methodology becomes effective for telecommunications carriers.[26] Section 703(7) of the 1996 Act added new Subsections 224(e)(1-4), which set forth a separate methodology to govern charges for pole attachments used to provide telecommunications services.[27]

5. In *Implementation of Section 703(e) of the Telecommunications Act of 1996*, CS Docket No. 97-151 ("*Telecommunications Report and Order")*, the Commission adopted a separate methodology for pole attachments on poles ("*Telecommunications Pole Formula*") and in conduits ("*Telecommunications Conduit Formula"*) for providers of telecommunications services, including cable systems providing telecommunications services, after February 8, 2001.[28] Revisions to the *Cable Formula* and the formula for pole attachment rates in conduit systems adopted in this *Order* will apply to attachments made by cable systems and, until the *Telecommunications Pole Formula* and the *Telecommunications Conduit Formula* become effective in 2001, will also apply to attachments by telecommunications carriers providing telecommunications services.[29] After February 8, 2001,[30] the *Cable Formula* for poles and the formula adopted for pole attachments in conduit systems adopted in this *Order*, will continue to apply to pole attachments used by a cable television system, as long as the pole attachment

[21]2 FCC Rcd 4387 (1987).

[22]Pub. L. No. 104-104, 104 Stat. 56, 149-151 (codified at 47 U.S.C. § 224).

[23]47 U.S.C. § 224(d)(3).

[24]47 U.S.C. § 153(44).

[25]47 U.S.C. § 153(8); 47 U.S.C. § 602(5).

[26]*See* 47 U.S.C. § 224(d)(3) (only to the extent that such carrier is not a party to a pole attachment agreement) and 47 U.S.C. § 224(e)(4).

[27]47 U.S.C. § 224(e)(1-4).

[28]13 FCC Rcd 6777 (1998), ¶¶ 116-130.

[29]*See* 47 U.S.C. § 224(d)(3) (but only to the extent that such carrier is not a party to a pole attachment agreement); *cf.* 47 U.S.C. § 224(e)(1).

[30]*See* 47 U.S.C. § 224(d)(3).

is not also used to provide telecommunications services.[31]

6. In the *Notice*, we sought comment to evaluate the accuracy of the *Cable Formula*, to evaluate and revise certain accounting rules,[32] and to consider the continued applicability of certain presumptions.[33] We sought comment regarding a methodology for use in determining just and reasonable pole attachment rates for conduit systems.[34] We also sought comment on whether, due to the reported frequency with which accumulated depreciation balances exceed gross pole investment, a modification of the *Cable Formula* was necessary.[35]

III. PRICING METHODOLOGIES FOR USE IN POLE ATTACHMENT FORMULAS

A. Background

7. When Congress enacted Section 224 in 1978, it directed the Commission to institute an expeditious program for determining just and reasonable pole attachment rates. Legislative history indicates that Congress was concerned with regulatory complexity, opting for a simple plan requiring a minimum of staff, paperwork and procedures and the avoidance of a large-scale ratemaking proceeding.[36] Congress did not believe that special accounting measures or studies would be necessary because most cost and expense items attributable to utility pole, duct and conduit plant were already established and reported to various regulatory bodies, for example forms submitted to the Commission by local exchange carriers ("LECs") and to the Federal Energy Regulatory Commission ("FERC") for electric utilities.[37] Congress

---

[31]The statute states that the § 224(d) rate shall apply for any pole attachment used by a cable television system "solely to provide cable services, . . . [and] subsection (e), . . . shall also apply to the rate for any pole attachment used by a cable system or any telecommunications carrier . . . to provide any telecommunications service." 47 U.S.C. § 224(d)(3).

[32]*Notice* at ¶¶ 1, 30-37.

[33]*Notice* at ¶¶ 1, 17-20.

[34]*Notice* at ¶¶ 1, 38-46.

[35]*Notice* at ¶¶ 17, 21-29.

[36]*1977 Senate Report* at 21; see also NCTA Comments at 6-7.

[37]*1977 Senate Report* at 20 ("Further, there may be some difficulty in determining the components of "actual" capital costs. As to some of these factors, the committee expects that the Commission will have to make its best estimate of some of the less readily identifiable actual capital costs. Special accounting measures or studies should not be necessary."). *See also* 47 C.F.R. § 1.1404(g)(12), (h). Incumbent local exchange carriers ("ILECs") and competitive local exchange carriers ("CLECs") are regulated by the Commission Rules at 47 U.S.C. Title II. Electric, gas, water, steam and oil utilities are regulated by FERC, an independent regulatory agency within the Department of Energy under authority from the Federal Power Act of 1935, 49 Stat. 847; the Natural Gas Act of

also did not expect the Commission to re-examine the reasonableness of the cost methodologies that various regulatory agencies had sanctioned. Section 224(d)(1) describes two possible cost methodologies, incremental and fully allocated, each of which is based on the "actual" capital costs of construction and operation of the pole attachment infrastructure (poles, ducts, conduit and rights-of-way).[38] Since 1978, the Commission, in interpreting this statutory language, chose an embedded cost methodology, which has been upheld by the United States Supreme Court.[39] Congress expected that pole attachment rates based on incremental costs would be low, because utilities generally recover the make-ready or change-out charges directly from cable systems.[40] On the other hand, fully allocated costs constitute the basis of the upper boundary of the range of just and reasonable rates.[41] The Commission noted that in arriving at an appropriate rate, it is important to ensure that the attaching entity is not charged twice for the same costs, once for make-ready costs and again for the same costs if the business expense is reported in the corresponding pole or conduit capital account.[42]

B. Discussion

1. Modification of the *Cable Formula*

8. In the *Notice,* we solicited comment on proposed modifications to the *Cable Formula* and the Commission's rules relating to the maximum just and reasonable rates utilities may charge for pole attachments.[43] We also sought comment on whether a modification is necessary to improve the accuracy of

---

1938, 52 Stat. 821; the Natural Gas Policy Act of 1978, 92 Stat. 3350, Pub. L. No. 95-621; the Public Utility Regulatory Policies Act of 1978, 92 Stat. 3117, Pub. L. No. 95-617; and the Energy Policy Act of 1992, 106 Stat. 2776, Pub. L. No. 102-486.

[38]*See Gulf Power, et al. v. USA, et al.*, 998 F. Supp. 1386 (N.D. Fla. 1998), *aff'd*, 187 F.3d 1324 (11th Cir. 1999).

[39]*See First Report and Order*, 68 FCC Rcd 1585, ¶ 25*; aff'd*, *Second Report and Order*, 72 FCC 2d 59, ¶ 15*; see also FCC v. Florida Power Corporation*, 480 U.S. 245 (1987).

[40]*1977 Senate Report* at 19. "Make-ready" generally refers to the modification of poles or lines or the installation of guys and anchors to accommodate additional facilities. *See 1977 Senate Report* at 19. A pole "change-out" is the replacement of a pole to accommodate additional users. *Pole Attachment Order*, 2 FCC Rcd at 4405 n.3.

[41]72 FCC 2d 59, 72 at ¶ 23 (citing *1977 Senate Report* at 20) (emphasis added).

[42]*Second Report and Order*, 72 FCC Rcd 59, ¶ 15; *see also American Cablesystems of Florida, Ltd. v. Florida Power & Light Co.*, PA 9-0012, 10 FCC Rcd at 10934, 10935, ¶ 10 (*rel.* June 15, 1995).

[43]*Notice*, 12 FCC Rcd 7449 (1997) at ¶ 5. We proposed a re-evaluation of the current formula methodology to improve the accuracy in the continued application of the formula to cable television systems and to telecommunications carriers pursuant to the 1996 Act.

the *Cable Formula*.[44] We did not specifically raise the issue of forward looking costs in the *Notice* in this proceeding. However, in response to the *Notice*, American Electric submitted comments supporting a methodology for determining a just and reasonable rate for pole attachments which employs forward looking economic cost pricing.[45] Electric utility pole owners assert that such a methodology is necessary to appropriately compensate them for pole attachments made by telecommunications carriers. This position is vehemently opposed by most attaching entities. The utilities' argument is articulated in a report prepared by the Reed Consulting Group ("Reed Report"), submitted by American Electric, which argues that the Commission should take a new perspective on the *Cable Formula*. The Reed Report contends that the electric utilities do not possess market power; their facilities are not essential; they do not compete directly with cable or telecommunications companies; they do not enjoy unequal bargaining power; and they have no motivation to restrict access.[46] Based on these arguments, the Reed Report concludes that pole attachment rates should be set through market negotiation or in the alternative, using replacement rather than historical costs in the *Cable Formula*. In order to reach its conclusion, the Reed Report defines the relevant market to include wireless technology and underground cable as alternatives to pole attachments. NCTA responds that Congress did not choose to repeal or modify the use of historical costs in the *Cable Formula*; that no certified state calculates pole rates based on reproduction costs; that there are no viable alternatives for the placement of cable and telecommunications facilities; and that the utilities do compete with cable and telecommunications providers.[47]

9. The Commission has employed historical costs in *Cable Formula* calculations since the passage of the Pole Attachment Act in 1978.[48] Further, the United States Supreme Court has upheld the application of an historical cost methodology for determining pole attachment rates.[49] Thus, for two decades the *Cable Formula* has provided a stable and certain regulatory framework, that may be applied “simply and expeditiously” requiring “a minimum of staff, paperwork and procedures consistent with fair and efficient regulation.”[50] Switching to a methodology based on forward-looking economic costs would

[44] *Notice*, 12 FCC Rcd at 7449 (1997), ¶ 1.

[45] *See* American Electric Comments at 14-95. American Electric was joined by other utility pole owners. *See, e.g.,* Duquesne Light Comments at 12-13; Edison Electric/UTC Comments at 14-15; Ohio Edison Comments at 12; Public Service of New Mexico Comments at 1.

[46] Reed Report at v.

[47] NCTA Reply at 12.

[48] *See First Report and Order*, 68 FCC Rcd 1585, ¶ 25; *aff’d, Second Report and Order*, 72 FCC 2d 59, ¶ 15*; see also Telecable of Piedmont, Inc. v. Duke Power Co.*, 10 FCC Rcd 10898 (1995).

[49] *FCC v. Florida Power Corporation*, 480 U.S. 245 (1987); *see also, Gulf Power v. USA*, 998 F. Supp. 1386 (N.D. Fla 1998), *aff’d,* 187 F.3d 1324 (11th Cir. 1999).

[50] *See* 1977 *Senate Report* at 21 (stating that it was the desire of the drafters “that the Commission institute a simple and expeditious CATV pole attachment program which will necessitate a minimum of staff, paperwork and

cause significant disruption and impose significant costs on attachers and this Commission. Such a change would require the Commission to develop a new formula that would necessitate a long and protracted rulemaking proceeding, and would likely involve complicated pricing investigations. In addition, such a change is likely to generate numerous complaints that the Commission would be required to resolve. Moreover, the Reed Report itself acknowledges that the use of a replacement cost methodology burdens regulators with a "long and tedious rate case process."[51] While we acknowledge that setting prices on the basis of forward-looking economic costs has significant advantages, including that it gives the appropriate signal for new entrants to invest in facilities, we believe these advantages are likely to be less pronounced in this context. We note that Congress has not expressed any intent for the Commission to deviate from the use of historical costs in the Cable Formula. We further note that the *Notice* did not specifically raise the possibility of shifting to a methodology based on forward-looking economic costs, and it therefore may not have been fully considered in the comments. Thus, we believe that in this particular context, after balancing all these factors, the disadvantages associated with changing to a methodology based on forward-looking economic costs would far outweigh any resulting benefits. For these reasons, we decline the electric utility pole owners' request to shift from the historical cost methodology at this time.

10. Based on all these factors, we will continue the use of historical costs in our pole attachment rate methodology. The continued use of a clear rate formula by the Commission is essential to encourage parties to negotiate for pole attachment rates, terms and conditions. We believe the continued use of historical costs accomplishes key objectives of assuring, to both the utility and the attaching parties, just and reasonable rates; establishes accountability for prior cost recoveries; and accords with generally accepted accounting principles.

2. Gross versus Net Book Costs

11. In the *Notice*, we sought comment on calculating pole attachment rates using gross book instead of net book costs. Currently, the *Cable Formula* incorporates net figures for the calculation of maximum pole attachment rates. Cable operators generally oppose a change to the use of gross book costs, contending that a) there are no regulatory or administrative efficiencies to be gained by moving to all gross book costs; b) net book costs would still be needed for return on investment computations; and c) the technical reasons offered by utilities in support of the use of gross book costs are not valid.[52] American Electric and other utility pole owners comment that the use of gross book costs are acceptable in the *Cable Formula* if the use of forward looking costs is not adopted by the Commission for pole attachment rates.[53]

---

procedures consistent with fair and efficient regulation").

[51] Reed Report at 20.

[52] *See, e.g.,* NCTA Comments at 24-25; Time Warner Comments at 24.

[53] *See, e.g.,* American Electric Comments at 70 (carrying charges for maintenance, depreciation, and administrative expense would be calculated based on gross book costs).

As we stated in the *Pole Attachment Order*, our preference is to use net figures.[54] The calculation of rate base items on a net basis is employed in the *Cable Formula* because that methodology reflects prior utility recovery of investment through depreciation, and prevents over-recovery of actual amounts invested.[55] We compute the carrying charge elements for maintenance, depreciation and administrative expenses, as well as for return on investment and taxes, using net book costs. For example, the net cost of a bare pole component is derived from the gross investment in poles less accumulated depreciation and accumulated deferred income taxes. The use of gross book costs in the *Cable Formula* would require that the carrying charge elements for maintenance, depreciation and administrative expenses be calculated using gross book costs for both total plant investment and pole investment. Even if gross book costs were used in the *Cable Formula*, the rate of return and the income tax carrying charges would continue to be computed using net book costs because utility prices are generally set to allow an authorized rate of return on net book costs. The use of gross book costs on a case by case basis does not appear to be inconsistent with the legislative history of Section 224, which indicates that the Commission has significant discretion in selecting a methodology for determining just and reasonable pole attachment rates.[56] In the past, if parties submitted calculations using gross book figures, we have calculated the maximum pole attachment rate using gross book costs.[57] The important goal is to ensure that like figures are used, whether net or gross and the Commission has stated that if both parties to a pole attachment complaint agree, the pole attachment rates may be computed using gross book costs.[58] We are not persuaded that our current preference for the use of net figures should be abandoned. Therefore, we will continue to use net figures in the *Cable Formula*. However, as in the past, when all parties to a complaint agree, we will allow the use of gross book costs.

---

[54] 2 FCC Rcd 4387 at n. 21 (1987).

[55] *See*, *1977 Senate Report*; *First Report and Order*, 68 FCC 2d 1585 (1978); *Second Report and Order*, 72 FCC 2d 59 (1979); *Third Order*, 77 FCC 2d 187 (1980); *see also Alabama Power Co. v. FCC*, 773 F.2d 362 (D.C. Cir. 1985) (upholding challenge to the Commission's pole attachment formula relating to net pole investment and carrying charges). Following *Alabama Power*, the Commission revised its rules in the *Pole Attachment Order*, 2 FCC Rcd 4387 (1987).

[56] *1977 Senate Report* at 9. *See, e.g.*, Bell Atlantic/NYNEX Comments at 3-4; Duquesne Light Comments at 13; Edison Electric/UTC Comments at 42-44; GTE Comments 4-8, Reply 5-6; SBC Comments at 2-6; Sprint Comments at 8-9; USTA Comments at 4-11, Reply at 6-8; *see also* American Electric Comments at 70-71 (do not object if at pole owner's discretion). *But see* AT&T Reply at 13-15; Association of Local Telecommunications Services Comments at 13-17; MCI Comments at 20; NCTA Comments at 24-25; Time Warner Comments at 24, Reply at 8-9; WorldCom Reply at 9-10.

[57] *See, e.g.*, *Capital Cities Cable, Inc. v. Southwestern Public Service Co.*, Mimeo No. 5431 (June 28, 1985*); Booth American Co. v. Duke Power Co.*, Mimeo 3064 (Com. Car. Bur., Mar. 22, 1984*); Teleprompter of Greenwood, Inc. v. Duke Power Co*., Mimeo 001866 (Com. Car. Bur., July 6, 1981).

[58] *See, e.g., TeleCable of Piedmont, Inc.*, 10 FCC Rcd 10898 (1995).

IV. ARMIS Uniform System of Accounts for LEC Pole Owners

12. In the *Notice*,[59] we proposed a formal revision of the *Cable Formula* for LECs so that it accurately reflects our current use of data from the Commission's Automated Reporting Management Information System ("ARMIS").[60] ARMIS Report 43-02 - Uniform System of Accounts ("USOA") contains the financial operating results of a LEC's telecommunications operations for every Part 32 account.[61] The *Cable Formula* codified by the *Pole Attachment Order* specifies particular Part 31 accounts to be used to calculate the pole attachment rates LECs may charge cable systems.[62] Previously LECs reported data collected in Part 31 accounts on an FCC Form M.[63] Effective January 1, 1988, Part 31 was replaced by Part 32, which changed how LECs account for and report certain costs.[64] For example, it appeared that the Part 31 accounts used in the *Cable Formula* included some non-administrative expenses in the administrative component of the carrying charges.[65] The proposed Part 32 accounts used in the *Cable Formula* would not include such non-administrative expense in the administrative component. The potential for inclusion of unrelated expenses in certain accounts must be balanced with the inability to recover other minor expenses that may have a legitimate nexus to pole attachments that are included in unrelated accounts. Our policy has been that not every detail of pole attachment cost must be accounted

[59]*Notice*, 12 FCC Rcd at 7449 (1997), ¶ 30.

[60]*Reporting Requirements for Certain Class A and Tier 1 Telephone Companies (Parts 31, 43, 67 and 69 of the FCC's Rules)*, CC Docket No. 86-182, 2 FCC Rcd 5770 (1987), modified on recon., 3 FCC Rcd 6375 (1988*) (rel.* Oct. 14, 1988*) (ARMIS Order).*

[61]ARMIS 43-02 USOA Report consists of three series of tables containing income statement, balance sheet, and general corporate data. This report, filed on an operating company basis, collects the operating results of the LEC's total activities for every account in the USOA, as specified in Part 32 of the Commission's rules. *See* 47 C.F.R. Part 32. ARMIS is available on the Commission's Internet web site at *http://www.fcc.gov/ccb/armis/*. The ARMIS database allows users to custom select data by report, year, company, study area, or individual data items. Data are available for years 1990 through 1997 and is updated regularly. The Internet availability and subsequent use of this information are expected to expedite calculations the of pole attachment formula.

[62]*Pole Attachment Order,* 2 FCC Rcd at 4387, 4403, Appendix B (1987).

[63]*Pole Attachment Order,* 2 FCC Rcd 4387 (1987); *see also* 47 C.F.R. § 1.1401-1.1416.

[64]*Revision of the Uniform System of Accounts and Financial Reporting Requirements for Class A and Class B Telephone Companies (Parts 31, 33, 42, 43 of the FCC's Rules), Report and Order*, 51 Fed. Reg. 24745 (July 8, 1986) and 51 Fed. Reg. 43493 (December 2, 1986) *("New USOA - Part 32 Adoption"); recon. in part, Memorandum Opinion and Order*, 2 FCC Rcd 1086 (rel. February 18, 1987).

[65]The Commission's Common Carrier Bureau has provided guidance to telephone companies and cable systems on applying the formula using Part 32 accounts. Letter from Kenneth P. Moran, Chief, Accounting and Audits Division, Common Carrier Bureau, to Paul Glist, Esq., Cole, Raywid & Braverman, 5 FCC Rcd 3898 (Com. Car. Bur., June 22, 1990) ("*Part 32 Guidance Letter*").

for, nor every detail of non-pole attachment cost eliminated from every account used.[66] The adoption of Part 32 would not alter our policy in that regard.

13. There was no opposition in the record, and substantial encouragement,[67] to the codification of the use in the *Cable Formula* of Part 32 accounts reported to the ARMIS. Adoption of Part 32 accounts will facilitate public access to data on which to determine just and reasonable pole attachment rates.[68] We affirm the use of Part 32 Uniform System of Accounts for LECs, as reported to ARMIS, in determining various components of the *Cable Formula*. These specific accounts are discussed in this *Order* relating to various aspects of the *Cable Formula*.

V. FORMULA FOR DETERMINING ATTACHMENT RATES FOR POLES

14. The Commission uses the following *Cable Formula* in disputed cases to set rates to be charged by utilities for attachments on poles:[69]

$$\text{Maximum Rate} = \frac{\text{Space Occupied}}{\text{Total Usable Space}} \times \text{Cost of a Bare Pole} \times \text{Carrying Charge Rate}$$

15. In the *Notice*, we sought comment on the continued applicability of various factors and elements within this formula.[70] In *Implementation of Section 703(e) of the Telecommunications Act of 1996, Notice of Proposed Rulemaking* ("*Telecommunications Notice*"),[71] we also sought comment regarding whether wind and weight load factors should be considered in the pole attachment rate and deferred discussion and decision on that issue to this rulemaking.[72]

A. Percentage of Total Usable Space Occupied

1. Background

---

[66] *See American Cablesystems of Florida, Ltd.*, 10 FCC Rcd 10934 (1995).

[67] *See, e.g.,* Bell Atlantic/NYNEX Comments at 5; BellSouth Comments at 5-6; NCTA Comments at 29 (but still object to paying for utilities' strategic planning, etc.); SBC Comments at 22; USTA Comments at 16.

[68] *Part 32 Guidance Letter*, 5 FCC Rcd 3898 (1990).

[69] *Pole Attachment Order*, 2 FCC Rcd 4387 (1987) at ¶ 6; 47 U.S.C. §§ 224(b)(1), (d).

[70] *Notice*, 12 FCC Rcd at 7449, ¶¶ 17-37.

[71] 12 FCC Rcd 11725 at ¶ 18 (1997).

[72] *Telecommunications Report and Order*, 13 FCC Rcd 6777 (1998) at ¶25.

16. In the *Second Report and Order*, consistent with Section 224(d)(2) and Congressional intent, the Commission defined total usable space as the space on the utility pole above the minimum grade level that is usable for the attachment of wires, cables, and related equipment.[73] Based upon survey results, consideration of the National Electric Safety Code ("*NESC*"),[74] and practical engineering standards used in constructing utility poles, the Commission found that "the most commonly used poles are 35 and 40 feet high, with usable spaces of 11 to 16 feet, respectively."[75] In the *Third Order,* the Commission relied on *NESC* guidelines and data received in its rulemaking proceedings to affirm the presumption of an average 18 feet for minimum ground clearance, referring to Congressional findings that " . . . the typical utility pole [is] 35 feet in length [and] has 11 feet of usable space leaving a total of 24 feet for both the portion buried underground [6 feet] and the necessary ground clearance [18 feet].[76] To avoid a pole by pole rate calculation, the Commission adopted rebuttable presumptions of (1) an average 37.5 foot pole height; (2) 13.5 feet of usable space; and (3) one foot as the amount of space a cable television attachment occupies.[77] These presumptions serve as the premise for calculating pole attachment rates under the current formula.

17. In anticipation of the *Notice*, a group of electric utilities filed a white paper ("*White Paper*"),[78] intended to facilitate the exchange of ideas among parties interested in matters related to pole and conduit attachments.[79] The *White Paper* asserts that over time and with increased demand for pole space the average pole height has increased to 40 feet, and that the usable space presumption should be

---

[73] *See* 72 FCC 2d at 69; 47 C.F.R. § 1.1402(c).

[74] The National Electrical Safety Code® ("*NESC*"), published by the Institute of Electrical and Electronics Engineers, Inc. ("IEEI") adopts certain standards that cover basic provisions for safeguarding persons from hazards arising from the installation, operation, or maintenance of (1) conductors and equipment in electric supply stations, and (2) overhead and underground electric supply and communication lines. *NESC*, 1997 Edition (published August 1, 1996) Abstract and § 1, p. 1. The *NESC* is a voluntary standard; however, some editions and some parts have been adopted, with or without changes, by some state and local jurisdictional authorities. *NESC*, p. vi.

[75] 72 FCC 2d at 69.

[76] *Third Order,* 77 FCC 2d 187 n.8 (1980) (referencing the *1977 Senate Report* at 20); *see also Second Report and Order,* 72 FCC 2d at 68 n.21.

[77] 72 FCC 2d at 69-70. In the *Telecommunications Report and Order,* we affirmed the one foot presumption for attachments made by telecommunications carriers. 13 FCC Rcd 6777 (1998) at ¶ 91.

[78] *See White Paper* filed by the law firm of McDermott, Will and Emery on August 28, 1996, on behalf of the American Electric Power Service Corporation, Commonwealth Edison Company, Duke Power Company, Entergy Services, Inc., Florida Power and Light Company, Northern States Power Company, The Southern Company and Washington Water Power Company.

[79] American Electric Reply at 2.

reduced from 13.5 feet to 11 feet.[80] In 1984, the Commission, in an order denying a petition filed by some of the utilities now sponsoring the *White Paper*, *Petition to Adopt Rules Concerning Usable Space on Utility Poles*, FCC 84-325 (*"Usable Space Order"*)[81] rejected the same arguments for changing the usable space presumptions as they again put forward.

18. In the *Notice*, we sought comment on the 37.5 foot presumptive pole height, the 13.5 foot usable space presumption, the average 18 foot minimum ground clearance, the allocation of the 40-inch safety space to usable space, the exclusion of 30 foot poles from the calculation of costs of a bare pole and whether 30 foot poles lack a sufficient amount of usable space to accommodate multiple attachments.[82]

2. Discussion

19. The presumptions used in the *Cable Formula* have been repeatedly affirmed since the enactment of the Pole Attachment Act.[83] We again decline to modify the well established presumptions leading to 7.4% as the percentage of usable space occupied by a pole attachment.[84] Commenters are divided on this issue, with pole owners asserting they should be entitled to higher rates[85] that would result from their desired presumption changes, and attaching entities quoting Congressional intent, Commission precedent and widespread industry practice to counter the arguments.[86] We are not persuaded by specific current industry data from electric utilities to change the usable space presumptions.

---

[80]*White Paper* at 11.

[81]Unpublished Order *(rel.* July 25, 1984).

[82]*Notice* at ¶¶ 18-20.

[83]*First Report and Order*, 72 FCC 2d 59; *Second Report and Order*, 77 FCC 2d 187, 191-193*; Cable Information Services, Inc. v. Appalachian Power Co.*, 81 FCC 2d 383 (1980*); Television Cable Service, Inc. v. Monongahela Power Co*., 88 FCC 2d 56 (D.C. Cir. 1981).

[84]The ratio of space occupied (presumptive 1 foot) over usable space (presumptive 13.5 feet) results in a factor of 0.074 for use in calculations of the *Cable Formula*.

[85]*See, e.g.,* American Electric Comments at 48; Carolina Power Comments at 74; Edison Electric/UTC Comments at 34; Ohio Edison Comments at 11; Union Electric Comments at 20.

[86]*See, e.g.,* Association for Local Telecommunications Services Comments at 5; Ameritech Comments at 3; AT&T Comments at 17; MCI Comments at 5; WorldCom Reply at 12. *Cf.* NCTA Comments at 9-15 (actual average pole height is increasing, but there is no basis for reducing the 13.5 feet usable space presumption in the pole formula).

a. Safety Space

20. A 40-inch safety space was created to minimize the likelihood of physical contact between employees working on cable television or telephone lines and the potentially lethal voltage carried by the electric lines, as well as to prevent electrical contact between such cables.[87] In the *Second Report and Order*,[88] and the *Third Order*,[89] the Commission rejected the arguments of electric companies that the entire 40 inches of safety space should be attributable to cable television operators. In the *Notice*,[90] we sought comment on the continued validity of the allocation of the 40-inch safety space to usable space. After consideration of the evidence in this proceeding, we decline to decrease the amount of usable space from 13.5 feet to 11 feet by reallocating the 40-inch safety space as unusable space. Removing the 40-inch safety space from usable space, under Section 224(d), would have the effect of spreading the costs of the safety space among the utility pole owner and the attaching entity.[91]

21. Some electric utilities request that we remove the 40-inch safety space from the presumptive 13.5 feet of usable space because the safety space exists to protect attaching entities' workers when installing and maintaining their pole attachments.[92] Attaching entities assert that any cable operator or telecommunications carrier seeking to install a pole attachment is already required to incur "make-ready" expenses to ensure the existence of the 40-inch safety space, and that electric utilities benefit from the safety space by attaching their own facilities such as communications equipment, street lights, transformers, and grounded, shielded power conductors in the safety space.[93]

22. It is the presence of the potentially hazardous electric lines that makes the safety space necessary and but for the presence of those lines, the space could be used by cable and telecommunications attachers.[94] The space is usable and is used by the electric utilities. A bare pole, when erected has portions

---

[87]*See, Second Report and Order*, 72 FCC 2d 59, 69-70 (*citing NESC* at Appendix C, at 163, Table 235-5 (1977 ed.) at n. 25.

[88]*Id*.

[89]77 FCC 2d 187 (1980).

[90]12 FCC Rcd 7449 (1997) at ¶ 19.

[91]47 U.S.C. § 224(d)(1), (2).

[92]*See, e.g.*, American Electric Comments at 51; Carolina Power Comments at 33; Duquesne Light Comments at 20; Edison Electric/UTC Comments at 30; Public Service of New Mexico Comments at 6; Union Electric Comments at 21.

[93]*See, e.g.*, Time Warner Comments at 15; USTA Comments at 23; *see also Second Report and Order*, 72 FCC 2d at 71.

[94]*See, e.g.*, NCTA Comments at 12; TCI Comments at 14; Time Warner Comments at 15, U S West Comments

to which attachments cannot be made at any time—the ground clearance and the part of the pole below ground. The rest is available for attachments; it is usable space. A communications attachment, even though it may be a fiber optic cable with a diameter of only one inch, is presumed to occupy one foot of the attachable space because of separation requirements. In a like manner, the electric supply cable on the pole, because of its unique spacing requirements must be 40 inches away from communications attachments. No one questions that the eleven inches of space not physically occupied by a fiber optic cable, but attributed to it, is usable space. Because the electric supply cable precludes other attachments from occupying the safety space, which would otherwise be usable space, the safety space is effectively usable space occupied by the supply cable. So long as their crews make the installation, the electric utilities are not limited by the *NESC* in what equipment or cables they may attach in the safety space. Accordingly, we reject the electric utilities' arguments to reduce the presumptive usable space of 13.5 feet by 40 inches.

b. Minimum Ground Clearance

23. In the *Second Report and Order*, the Commission established that a presumptive average 18 feet of the pole space is reserved for ground clearance.[95] The 18 foot presumption is not dictated by the National Electric Safety Code ("NESC"),[96] but is an average to be used in the estimation of total usable space.[97] In the *Usable Space Order*, we determined that the selection of the 18 foot figure reflected various elements such as differing pole heights, as well as NESC standards that vary depending on the physical environment of the pole.[98] Factors used to determine the NESC standard of minimum ground clearance, include whether the wires or cables cross over railroad tracks, roads, or driveways and the amount of voltage transferred through the cables.[99] In response to the *Notice*, some electric utilities suggest that the lowest attachment on a pole must be at least 19'8" from the ground in order to accommodate

---

at 5. *But see*, Sprint Comments at 4 (since all attaching parties are required to comply with the *NESC*, the space should be regarded as unusable).

[95]72 FCC 2d 59, 69-70 (1979); National Electric Safety Code ("*NESC*") Appendix C, Table 235-5, p. 163 (1977 ed.); MCI Comments at 10.

[96]*NESC* Rule 232, Vertical Clearances of Wires, Conductors, Cables, and Equipment Above Ground, Roadway, Rail, or Water Surfaces provides narrative and table references for various clearances [clearance is defined as the clear distance between two objects measured surface to surface (*NESC*, § 2, at p. 5)] under a variety of circumstances, involving a variety of types of electric and communications equipment, and in a variety of environments.

[97]*See* MCI Comments at 10.

[98]*Usable Space Order*, slip op. at ¶ 11.

[99]*NESC* at 77, Table 232-1 (1997 Edition).

communications cable sag.[100] The electric utilities provide us with "average" sag for a "typical" communications cable, but do not indicate how either was determined.[101] In the *Usable Space Order* we carefully considered numerous studies submitted to us before concluding that the 18 foot figure was an appropriate tool to estimate usable space.[102] The data provided by the utilities regarding sag does not demonstrate the same rigor as the studies on which our *Usable Space Order* was based.[103]

24. The rebuttable nature of the usable space presumption allows for the use of a different minimum ground clearance when necessary to improve the accuracy of the calculations.[104] Presumptions were adopted to encourage expeditious response to complaint information requests.[105] We have not been persuaded that a departure from our well established presumption of an average minimum ground clearance of 18 feet is warranted.[106]

c. 30 Foot Poles

25. In the *Notice*, we sought comment on whether 30 foot poles lack a sufficient amount of usable space to accommodate multiple attachments and whether including poles of 30 feet or less in the total number of poles for calculating the *Cable Formula* results in a distorted rate.[107] The *White Paper* contends that poles of 30 feet or less lack a sufficient amount of usable space to accommodate multiple attachments, and suggests that the inclusion of these poles in the calculation results in an inexact

---

[100] *See, e.g.*, American Electric Comments at 48-50.

[101] *See, e.g.*, American Electric Comments at 48-50.

[102] *Usable Space Order*, slip op. at ¶ 12.

[103] Section 1.1404(g)(11) states that 13.5 feet may be used in lieu of actual measurement as the amount of usable space, but that it may be rebutted. 47 C.F.R. § 1.1404(g)(11). We have stated that a survey that yields a statistically reliable result would be acceptable. *See Second Report and Order* at ¶ 21. Such a survey must meet the requirements of Section 1.363 of the Commission's Rules. 47 C.F.R. § 1.363.

[104] *See NESC* (1997 edition), Forward at vi.; *see also* Ohio Edison Comments at 21-22 (arguing that the Commission's rules should expressly allow a utility to use a different average of usable space for its rate calculations than the Commission's rebuttable presumption if state law requires a minimum ground clearance at the pole of more than 18 feet).

[105] *1977 Senate Report* at 21.

[106] *See, e.g.*, Ameritech Comments at 3; AT&T Comments at 17; Bell Atlantic/NYNEX Comments at 11; NCTA Reply at 37-38.

[107] *Notice* at ¶ 20.

determination of the actual net costs of a bare pole.[108]

26. We have not been presented with evidence that a pole attachment rate based on pole inventory, in which 30 foot poles are included, fails to adequately compensate a pole owner. We have received significant information to the contrary.[109] Telecommunications carriers disagree with the utilities' argument to exclude 30 foot poles from the bare pole calculation.[110] The record confirms the prevalent use of 30 foot poles and reflects that exclusion of such poles from the *Cable Formula* calculations could distort the resulting rate by excluding a significant portion of LEC plant investment from the rate calculation.[111] With a presumed ground clearance of 18 feet, a 30 foot pole has six feet of usable space. A 30 foot electric utility pole can accommodate two communications attachments or more with overlashing. A 30 foot LEC pole can accommodate more.[112] We conclude that a distorted inventory of poles would be reflected if utilities were allowed to "opt out" or exclude their poles of 30 feet or less when calculating their pole attachment rates.[113]

d. Weight and Wind Load Factors

27. In the *Telecommunications Notice* we sought comment on an issue raised by Duquesne Light in its Petition for Reconsideration ("*Duquesne Petition*") of the Commission's decision in *Implementation of the Local Competition Provisions of the Telecommunications Act of 1996, First Report and Order, CC Docket No. 96-98 ("Local Competition Order")*.[114] The *Duquesne Petition*

---

[108] *White Paper* at 12-13.

[109] *See, e.g.*, NCTA Comments at 15-18 (LECs use significant numbers of 30-foot poles); Sprint Comments at 4-5 (still use many 30 foot poles); USTA Comments at 27-29 (LECs use substantial numbers of 30-foot poles); U S West Comments at 4 (over 13% of inventory is 30 feet or less). *Cf.* American Electric Comments at 55-57; Carolina Power Comments at 29; Edison Electric/UTC Comments at 29 (Electric utilities do not use many 30-foot poles and do not account for them separately).

[110] Ameritech Comments at 4; AT&T Comments at 10; Bell Atlantic/ NYNEX Comments at 10; GTE Comments at 13; MCI Comments at 12; SBC Reply at 39; Sprint Comments at 4; USTA Comments at 27.

[111] *See, e.g.*, GTE Reply at 13; NCTA Comments at 12-16, Reply at 21-22; Ohio Edison Comments at 26; SBC Comments at 38-39; TCI Comments at 13; Time Warner Comments at 11-13, 18-19; U S West Comments at 4.

[112] *See, e.g.*, Ameritech Comments at 4; AT&T Comments at 18; NCTA Comments at 4-5, Reply at 21-24.

[113] *See, e.g.*, Ameritech Comments at 4; AT&T Comments at 10; Bell/NYNEX Comments at 10; GTE Comments at 13; MCI Comments at 14; NCTA Comments at 15; Public Service of New Mexico Comments at 6; SBC Reply at 39; Sprint Comments at 5; TCI Comments at 13; Time Warner Comments at 12-13; USTA Comments at 28-29; U S West Comments at 4.

[114] *Telecommunications Notice*, 12 FCC Rcd at 11725, ¶ 18 (citing *Local Competition Order*, FCC 96-325, 11 FCC Rcd 15499 at 16058-107, ¶¶ 1119-1240 (1996)); *see also* Duquesne Light CC Docket No. 96-98 Comments

requests that the Commission recognize, and incorporate into its rate formula, that various attachments place difference burdens on the poles. Duquesne Light asserts that presumptions used in the *Cable Formula* should include factors addressing weight and wind loads.[115] For instance, Duquesne Light claims that overlashing of an attachment will increase the loading on the pole, especially during adverse icy and windy weather conditions. Duquesne Light maintains that an increase in loading could cause a pole to lean, lines to sag or the pole to break or collapse. This increase in loading, Duquesne Light argues, necessitates the charging of an additional fee for the overlashed cable, as well as treatment of the overlash as a separate attachment.[116] In the *Telecommunications Report and Order*, we reserved decision on the weight and wind load issues until the resolution of the rulemaking currently before us.[117] We will therefore address at this time whether any presumptions should reflect these factors.

28. Consideration of loading, including weight and wind load, relates to engineering of the pole structure. Sections 24 through 26 of the NESC address considerations of loading and structural requirements in detail.[118] We do not believe that an attachment "burden on the pole" relates to anything other than an assessment of need for make-ready changes to the pole structure, including pole change-out, to meet the strength requirements of the NESC. Make-ready costs are non-recurring costs for which the utility is directly compensated and as such are excluded from expenses used in the rate calculation.[119] We agree with USTA that the statutory language for allocating costs in Section 224 refers to space, not load capacity.[120]

29. We are not convinced that "burden on the pole" due to weight and wind load is an additional factor for consideration in the determination of the amount of space occupied.[121] Wind and weight loading factors, as calculated using NESC rules,[122] increase as the cross-sectional area of the wire

---

at 17-18.

[115]Duquesne Light CC Docket No. 96-98 Comments at 17-18; Duquesne Light CS Docket No. 97-151 Comments at 36.

[116]Duquesne Light CS Docket No. 97-151 Comments at 26-28.

[117]*Telecommunications Report and Order*, 12 FCC Rcd at 11725, ¶ 25.

[118]*NESC* at 142-168, Sections 24-26.

[119]*See Second Report and Order*, 72 FCC 2d 59, at ¶ 27.

[120]47 U.S.C. § 224(d); *see also, e.g.,* USTA Reply at 13-14.

[121]For discussion of applicability of the one foot presumption for cable operators, see ¶¶ 28, 35 of this *Order; see also, Telecommunications Report and Order*, 13 FCC Rcd 677 at ¶¶ 80-92 for applicability to telecommunications carriers.

[122]*NESC* Rule at 148 (1997 Edition).

increases. The NESC calculations use the worst case scenario where the wind is blowing parallel to the ground and perpendicular to the side of the cable, wire, conductor, etc., creating maximum wind resistance. The surface area presented to the wind is directly proportional to the diameter or vertical dimension of the wire, conductor, cable, etc.[123] As the vertical dimension increases, and therefore, the surface area increases, the wind load factor increases. It is the vertical dimension of the wire that determines how much space is occupied on the pole. The current method for allotting space to a pole attachment, therefore, accounts directly for the wind load factor. The weight load factor is considered when deciding whether a stronger pole is necessary as part of make-ready work.

30. Further, the inclusion of factors such as wind and weight load in the presumptions could lead to unacceptable over-recovery. Many of the factors have already been included in accounts in the maintenance element of the carrying charge rate. For electric utility owned poles, FERC Account 593 includes pole related expenses for overhead lines and allows for the recovery of the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution facilities. This account includes expenses for repair pole related equipment and adjusting the sag of attachments to the pole.[124] The Commission's ARMIS rules for LEC accounting provide for the recovery of damages and pole related expenses caused by storms or other casualties.[125] The complete costs of the physical attachments of an attaching entity are normally paid to the pole line owner as a condition of attachment, addressing such factors as weight, wind load and safety space.[126] These make-ready costs have been fully recovered. It would be inappropriate to allow for their recovery again through the pole rate.

B. Cost of a Bare Pole

31. In the *Pole Attachment Order*, the Commission promulgated a methodology to arrive at the net cost of a bare pole for use in the *Cable Formula*[127] from a calculation of the total investment in poles less accumulated depreciation for poles, and less accumulated deferred income taxes.[128] An

[123]The surface of the cable presented the wind is approximately a rectangle with a length equal to the distance between the poles(l) and a height equal to the half the cumulative circumferences of the wires (in the worse case) ($\frac{1}{2}\pi d_1+\frac{1}{2}\pi d_2+\frac{1}{2}\pi d_3+\ .\ .\ .$). The surface area is then l X $\frac{1}{2}\pi(d_1+d_2+d_3)$ when a cable is overlashed with another cable above and one below and it increases proportionately as the cumulative diameter increases.

[124]*See* 18 C.F.R. Part 101 (Uniform Systems of Accounts Prescribed for Public Utilities And Licensees Subject to the Provisions of the Federal Power Act) Account 593.

[125]47 C.F.R. §§ 32.5999(b)(3), 32.6410, 32.6411.

[126]*See, e.g.*, NCTA Comments at 15-16; Summit CS Docket No. 97-151 Comments at 1.

[127]*See Pole Attachment Order*, 2 FCC Rcd 4387 (1987) at ¶¶ 10-19 & Appendix B. The *Pole Attachment Order*, used the term "depreciation reserve" in this formula. We have updated our terminology to reflect Generally Acceptable Accounting Principles (GAAP) and use the term "accumulated depreciation."

[128]*Pole Attachment Order*, 2 FCC Rcd 4287, at ¶¶ 10-19 & Appendix B.

adjustment to a utility's net pole investment (of 15% for electric utilities and 5% for LECs) is necessary to eliminate the investment in crossarms and other non-pole related items.[129]

1. LEC Pole Owner Formula Methodology

32. The *Pole Attachment Order* prescribed a formula for determining the net cost of a LEC's bare pole, using the old Form M, Part 31 Account 241 (Gross Pole Investment), as follows:[130]

$$\begin{matrix}\text{Net Cost of} \\ \text{a Bare Pole}\end{matrix} = \frac{\begin{matrix}\text{Gross Pole Investment} \\ \text{(Account 241)}\end{matrix} - \begin{matrix}\text{Depreciation Reserve} \\ \text{(Poles)}\end{matrix} - \begin{matrix}\text{Accumulated Deferred} \\ \text{Income Taxes (Poles)}\end{matrix} - \begin{matrix}\text{0.05 of} \\ \text{Net Pole Investment}\end{matrix}}{\text{Total Number of Poles}}$$

33. In the *Notice*, we proposed a revised formula to determine a value for the net cost of a bare pole using the ARMIS Part 32 Account 2411 (Gross Pole Investment) for LEC pole owners, applying the 5% (or 0.95) adjustment factor.[131] Based on the record, we affirm our proposed formula to determine the net cost of a bare pole for LEC pole owners under the following formula:[132]

$$\begin{matrix}\text{Net Cost of} \\ \text{a Bare Pole} \\ \text{(LEC)}\end{matrix} = 0.95 \text{ x } \frac{\text{Account 2411} - \begin{matrix}\text{Accumulated Depreciation} \\ \text{(Account 3100)(Poles)}\end{matrix} - \begin{matrix}\text{Accumulated Deferred} \\ \text{Income Taxes (Account 4100 + 4340)(Poles)}\end{matrix}}{\text{Number of Poles}}$$

34. In this formula Accumulated Depreciation (Poles) and Accumulated Deferred Income Taxes (Poles) are derived from composite Part 32 accounts attributable to poles. Specifically, Accumulated Depreciation (Poles) represents the share of Part 32 Account 3100 (Accumulated Depreciation) that corresponds to Account 2411, and Accumulated Deferred Income Taxes (Poles) represents the shares of Part 32 Accounts 4100 (Net Current Deferred Operating Income Taxes) and 4340

[129]*See Pole Attachment Order*, 2 FCC Rcd at 4387, 4390, (1987) at ¶ 19. The two factors reflect the differences between LECs' and electric utilities' investment in crossarms and other non-pole investment that is recorded in the pole accounts. Electric utilities typically have more investment in crossarms than LECs. The 0.85 factor for electric utilities recognizes this difference. These adjustment factors are rebuttable. *See also, Notice* at ¶ 42.

[130]*Pole Attachment Order*, 2 FCC Rcd 4287, Appendix B. FCC Form M Part 31 Accounts 171 [Depreciation Reserve] and 176.1 [Deferred Income Taxes (Accumulated)] were composite accounts that were required to be maintained on a subsidiary basis, and therefore apportionment of these accounts were necessary to determine pole rates. In other words, Depreciation Reserve (Poles) represented the share of FCC Form M Part 31 Account 171 that corresponded to Account 241 (Gross Pole Investment), and Accumulated Deferred Income Taxes (Poles) represented the share of FCC Form M Part 31 Account 176.1 that corresponded to Account 241.

[131]*Notice* at ¶ 42.

[132]*Notice* at Appendix A.

(Net Noncurrent Deferred Operating Income Taxes) that correspond to Account 2411.[133]

35. The formula, as adopted, updates the *Cable Formula* to reflect current regulatory accounting practices by LECs, and clarifies the method for accurately deriving the proper figure for accumulated deferred income taxes when used in conjunction with the pole attachment formula.[134] This formula updates the *Cable Formula* in a manner that is equitable to all parties by providing consistency in calculating a pole attachment rate based on publicly available and verifiable data.[135] The adjustment to the *Cable Formula* also recognizes more accurately the accumulated deferred taxes related to pole investment than would proration based upon a ratio of pole investment to total plant in service.

2. Electric Utility Pole Owner Formula Methodology

36. The *Pole Attachment Order* prescribed a formula for determining the net cost of a bare pole for electric utilities using FERC Accounts[136] as follows:[137]

$$\text{Net Cost of a Bare Pole} = \frac{\begin{array}{c}\text{Account 364}\\ \text{(Gross Pole}\\ \text{Investment)}\end{array} - \begin{array}{c}\text{Depreciation Reserve}\\ \text{(Poles)}\end{array} - \begin{array}{c}\text{Accumulated Deferred}\\ \text{Income Taxes (Poles)}\end{array} - \begin{array}{c}\text{0.15 of}\\ \text{Net Pole Investment}\end{array}}{\text{Number of Poles}}$$

37. In the *Notice*,[138] we stated the formula includes factors appropriate for arriving at the net cost of a bare pole for electric utility pole owners. In response to the *Notice*, some electric utilities assert that FERC Accounts 365 (Overhead Conductors and Devices) and 368 (Line Transformers) should be included in the calculations to determine the net cost of a bare pole.[139]

---

[133] *Part 32 Guidance Letter*, 5 FCC Rcd 3898 (1990). For Account 3100, *see* ARMIS Report 43-02, row 0390. The subsidiary accounts for Accounts 4100 and 4340 are required to be maintained and reported to the Commission. *See* 47 C.F.R. §§ 43.21, 43.43, 32.4100 and 32.4340. *See also*, Biennial Regulatory Review, Review of Accounting and Cost Allocation Requirements, FCC 99-106 at ¶ 15 (*rel*. June 30, 1999) and Biennial Regulatory Review, Review of ARMIS Reporting Requirements, FCC 99-107 at ¶ 13 (*rel*. June 30, 1999).

[134] *See* USTA Comments at 18. *Cf.* NCTA Reply at 34.

[135] *Pole Attachment Order*, 2 FCC Rcd 4387 (1987); *1977 Senate Report* at 19-20.

[136] FERC Account 364 is "poles, towers and fixtures." 18 C.F.R. Part 101, Description of Accounts.

[137] *Pole Attachment Order*, 2 FCC Rcd 4387, 4402-03, Attachment B (1987).

[138] *Notice* at ¶ 10.

[139] *Notice*, 12 FCC Rcd at 7449, ¶ 18. *See, e.g.*, American Electric Comments at 58-67; Carolina Power Comments at 43-58; Edison Electric/UTC Comments at 37-41.

38. We decline to add portions of Accounts 365 or 368 to the net cost of a bare pole factor. This factor already contains adjustment components, relating to appurtenances such as crossarms, that can be challenged with appropriate verifiable data.[140] We affirm our conclusion that lightning protectors and grounding installations recorded in accounts other than Account 364 should not be included in the calculation of the net cost of a bare pole factor.[141] Attaching entities are required to provide separate grounding for their own attachments.[142] Lightning protectors and grounding installed on poles by utilities are equipment specific to the electric utility's core business services and not related to the general cost of the pole plant. Portions of Accounts 365 and 369 are already included in the maintenance element of the relevant *Cable Formula*.[143]

39. We do not believe that portions of Accounts 580 (Operation: Supervision and Engineering) and 583 (Operation Overhead Line Expenses, Major Utilities Only) should be included even if they contain some capital expense incurred with respect to all electric power distribution plant.[144] Based on the record, we believe that any increased accuracy that would be derived from including some minute percentage of pole-related expenses that may be recorded in miscellaneous accounts, is outweighed by the complexity of arriving at an appropriate and equitable percentage of the expenses.[145] The descriptions of what expenses are to be reported in Accounts 365, 368,[146] 580 and 583, contained in FERC Part 101,[147]

[140]*See Pole Attachment Order*, 2 FCC Rcd 4387, 4390 (1987), ¶ 19 (appurtenance ratios (5% for telephone and 15% for electric utilities) [are] rebuttable presumptions to be used in the event no party chooses to present probative, direct evidence on the actual investment in non-pole-related appurtenances); *see also, e.g.*, AT&T Reply at 24-28; NCTA Comments at 19-21, Reply at 26.

[141]*Notice* at ¶ 18.

[142]*See, e.g.*, NCTA Comments at 19-20, NCTA Ex Parte Presentation March 12, 1998. *But see*, American Electric Comments at 58-67; Carolina Power Comments at 50-52; Electric Edison/UTC Comments at 37-41.

[143]*Pole Attachment Order*, 2 FCC Rcd 4387, 4402-03, Attachment B (1987); *see also* discussion of the maintenance element at Section V.C.2 of this *Order*.

[144]*See, e.g.*, Carolina Power Comments at 50-52.

[145]*See, e.g.*, MCI Reply at 31-33; NCTA Comments at 21 (if the Commission were to consider the addition of grounding systems into the rate formula, that inclusion would have to be spread across the utility investment in its entire distribution network), Reply at 26; Time Warner Comments at 19-22; *see also*, *Hearing Designation Order*, *American Cablesystems of Florida, LTD. v. Florida Power and Light Company*, PA 91-0012, CC Docket No. 95-95, 10 FCC Rcd 10934 at ¶ 10 (June 15, 1995); *Hearing Designation Order*, *TCA Management Co., et al., v. Southwestern Public Service Company*, PA 90-0002, CC Docket No. 95-84, 10 FCC Rcd 11832 (June 15, 1995).

[146]*See, e.g.*, MCI Reply at 31-33; NCTA Reply at 26.

[147]*See*, 18 C.F.R. Part 101: descriptions of (FERC) accounts and operating expense reporting instructions.

appear to relate more directly to the electric utilities' core business operations rather than "actual capital costs attributable to the entire pole, duct, conduit or right-of-way," as required for inclusion in the rate formula.[148]

40. In keeping with long-standing Commission precedent,[149] expenses relating to grounding systems should be excluded from the rate base because, like cross-arms and appurtenances, they are part of the electric utilities' entire system of conductors, rather than of poles.[150] In addition, costs for such equipment are often included in make-ready expenses that attaching entities pay on an up-front, non-recurring basis.[151] We also agree with cable operators and telecommunications carriers that contend the adoption of the electric utilities' proposals would have the significant disadvantage of requiring the allocation of portions of FERC accounts into rate-base calculations, turning virtually every rate dispute into a full-blown, discovery-laden rate case.[152]

41. We affirm the following formula to determine the net cost of a bare pole for electric utilities:

$$\begin{array}{c}\text{Net Cost of a}\\ \text{Bare Pole}\\ \text{(Electric)}\end{array} = 0.85 \times \frac{\text{Account 364} - \begin{array}{c}\text{Accumulated Depreciation}\\ \text{(Poles)}\end{array} - \begin{array}{c}\text{Accumulated Deferred}\\ \text{Income Taxes (Poles)}\end{array}}{\text{Number of Poles}}$$

42. Under this formula, Accumulated Depreciation (Poles) represents the share of FERC Account 108 (Accumulated provision for depreciation of electric utility plant (Major only) a composite account that is required to be maintained on a subsidiary basis, that corresponds to Account 364 (Poles,

[148]47 U.S.C. § 224(d)(1).

[149]*See, e.g.*, *Williamsburg Cablevision v. Carolina Power and Light Co*., PA 82-007, FCC Mimeo 1961 (Jan. 26, 1983); *American Television and Communications Corp. v. Wisconsin Power & Light Co*., PA No. 82-006, Mimeo 1678 (Jan. 4, 1985).

[150]In the *Notice*, 12 FCC Rcd at 7449 n. 55, we suggested that the costs of grounding systems may be included in FERC accounts currently used to calculate electric utilities' pole attachment rates. Asset accounts 364, 365, and 369 are used to calculate the maintenance component of the carrying charge rate. However, Account 364, reduced by 15% to account for appurtenances, is used as the pole rate base (net cost of a bare pole). The *White Paper* suggests that the grounding and arrestor systems booked to Account 365 should be added to this rate base. For the reasons set forth in this section, we believe they should not be. *See* NCTA Comments at 21 (if the Commission were to consider the addition of grounding systems into the rate formula, that inclusion would have to be spread across the utility investment in its entire distribution network); *see also* MCI Reply at 31-33; NCTA Reply at 26; Time Warner Comments at 19-22.

[151]*See, e.g.,* MCI Reply at 31-33; NCTA Reply at 26.

[152]*See, e.g.,* MCI Reply at 31-33; NCTA Reply at 26; Time Warner Comments at 19-22.

Towers, and Fixtures).[153] Similarly, Accumulated Deferred Income Taxes represents the share of composite FERC Account 190 (Accumulated deferred income taxes) that corresponds to Account 364.[154]

3. Total Number of Poles

43. We have previously concluded that poles of 30 feet or less should be included in calculations of the *Cable Formula* in our discussion about pole height and the usable space presumption.[155] Based on our review of the record in this proceeding, we also conclude that poles of 30 feet or less should therefore be included in the inventory of the total number of poles owned or used, jointly-owned or solely-owned, by a utility. The exclusion of these poles would result in a distorted and inaccurate pole inventory resulting in an unjust and unreasonable pole attachment rate because they are being used by the utility for their business services and by cable operators and telecommunications carriers to provide their respective services.[156]

C. Carrying Charge Rate (Poles)

44. The carrying charge rate[157] reflects those costs incurred by the utility in owning and maintaining poles regardless of the presence of pole attachments.[158] The elements of the carrying charge rate are: administrative, maintenance, depreciation, taxes and cost of capital (rate of return).[159] In the *Pole*

[153] 18 C.F.R. Part 101, General Instructions.

[154] *Id.*

[155] *See* discussion at Section V.A.2.c of this *Order*.

[156] *See, e.g.,* NCTA Comments at 15; SBC Reply at 39; USTA Comments at 28-29; U S West Comments at 4; *Cf., e.g.,* American Electric Comments at 55-57; Carolina Power Comments at 29; Edison Electric/UTC Comments at 29; *see also, e.g.,* Duquesne Light Comments at 18 (cannot separate out 30 foot poles from total inventory of poles).

[157] The annual carrying charge rate attributable to the cost of owning a pole are required to be provided in a pole attachment complaint. These charges may be expressed as a percentage of the net pole investment. Accumulated deferred taxes are used in calculating the administrative, maintenance and taxes elements of the carrying charge rate. The utility shall file a copy of the latest decision of the state regulatory body or state court which determines the treatment of accumulated deferred taxes with its pleading, if accumulated deferred taxes are at issue in the proceeding and shall note the section which specifically determines the treatment and amount of accumulated deferred taxes. 47 C.F.R. § 1.1404(g)(9).

[158] *Notice* at ¶ 11.

[159] *Pole Attachment Order*, 2 FCC Rcd at 4387, 4391 (1987), ¶ 25.

Attachment Order,[160] the Commission identified the regulatory accounts to be used, where possible, in applying the *Cable Formula* to determine the maximum allowable rate for pole attachments. The carrying charge rate factor of the *Cable Formula* is calculated as follows:[161]

$$\begin{matrix}\text{Carrying} \\ \text{Charge Rate}\end{matrix} = \text{Administrative} + \text{Maintenance} + \text{Depreciation} + \text{Taxes} + \text{Return}$$

To calculate the carrying charge rate, the Commission developed a formula that relates each of these elements to a pole owner's net pole investment.[162] The full *Cable Formula*, with all its components, elements and accounts used, is attached to this *Order* as Appendix C.

45. In May 1986, the Commission adopted a new uniform system of accounts for all FCC regulated telephone companies.[163] The Commission's Annual Report Form M was revised on April 27, 1989[164] to reflect the new accounting system in Part 32 that replaced the accounting system in Part 31, effective January 1, 1988.[165] The *Pole Attachment Order* provided formulas for determining a maximum just and reasonable pole attachment rate with regulatory accounts identified.[166] The formula for LECs used Part 31 accounts. After the *New USOA-Part 32 Adoption*, the Common Carrier Bureau responded to a request for clarification of what Part 32 accounts would be used in place of the Part 31 accounts specified in the *Pole Attachment Order*. That guidance was given with the understanding that an exact tracking of expenses from Part 31 accounts to Part 32 accounts was not possible.[167] In this *Order*, we formalize and further clarify the Part 32 accounts to be used in the *Cable Formula* for LECs utilities. LECs maintain their Part 32 accounts and file their annual operating costs with the Commission's Automated Reporting and Management Information System ("ARMIS").[168]

---

[160] 2 FCC Rcd 4387, 4402-03, Attachment B (1987); *see also American Cablesystems of Florida, Ltd.*, 10 FCC Rcd 10934 (1995).

[161] *Notice*, 12 FCC Rcd at 7449, Appendix A.

[162] *Pole Attachment Order*, 2 FCC Rcd at 4387, 4402-03, Attachment B (1987).

[163] *New USOA - Part 32 Adoption*, 51 Fed. Reg. 24745 (1986) and 51 Fed. Reg. 43493 (1986); *recon. in part*, 2 FCC Rcd 1086 (1987).

[164] Common Carrier Bureau, DA 89-503 (*rel.*, May 22, 1989).

[165] *Part 32 Guidance Letter*, 5 FCC Rcd 3898 (1990).

[166] 2 FCC Rcd 4387, 4402-03 (1987).

[167] *Part 32 Guidance Letter*, 5 FCC Rcd 3898 (1990).

[168] *Reporting Requirements for Certain Class A and Tier 1 Telephone Companies (Parts 31, 43, 67 and 69 of the FCC's Rules)*, CC Docket No. 86-182, 2 FCC Rcd 5770 (1987), *modified on recon.*, 3 FCC Rcd 6375 (1988) *(rel.* Oct. 14, 1988) (*"ARMIS Order*").

1. The Administrative Element

46. In the *Pole Attachment Order*, the Commission adopted procedures to identify and calculate administrative expenses, for use in the carrying charge rate as a ratio of total administrative and general expenses to total plant investment.[169] A formula for the administrative expenses[170] was given as follows:

$$\text{Administrative Expense} = \frac{\text{Administrative and General Expenses}}{\text{Gross Plant Investment} - \text{Depreciation Reserve} - \text{Accum. Deferred Taxes, Plant}}$$

47. In the *Notice*,[171] we proposed the following revised formula, using Part 32 accounts, for the administrative element for LECs:

$$\text{Administrative Element} = \frac{\text{Administrative and General (Accounts } 6710 + 6720 + 6110 + 6120 + 6534 + 6535)}{\text{Gross Plant Investment} - \begin{array}{c}\text{Accumulated Depreciation}\\ \text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accum. Deferred Taxes, Plant}\\ \text{(Accounts 4100 \& 4340)}\end{array}}$$

48. The substantive changes to the administrative element proposed in the *Notice*, based primarily on the adoption of Part 32,[172] included the addition of Accounts 6710 (Executive and Planning), 6720 (General and Administrative), 6110 (Network Support Expense), 6120 (General Support Expense), 6534 (Plant Operations Administration Expense), and 6535 (Engineering Expense).[173] Additionally, we proposed to exclude Account 6231 (Radio Systems Expense) because we believe that the expenses reported in this account are unrelated to the administrative element relating to pole attachments.[174] We also

[169]2 FCC Rcd at 4387, 4392 (1987), ¶ 37.

[170]The *Pole Attachment Order* labeled the elements of the carrying charge rate as "expenses" (2 FCC Rcd at 4387, 4402-03, Attachment (1987)) rather than "carrying charge rates" as we did in the *Notice* (12 FCC Rcd at 7449, Appendix A), e.g., administrative expense is labeled administrative element in our current formula elements of the carrying charge rate.

[171]*Notice* at ¶¶ 31-33.

[172]47 C.F.R. Part 32; *see also Part 32 Order*, 2 FCC Rcd 1086 (1987).

[173]*Notice*, 12 FCC Rcd at 7449, ¶ 31.

[174]*Notice*, 12 FCC Rcd at 7449, ¶ 32; *see also* 47 C.F.R. §§ 32.6231, 32.2231(a). Account 6231 includes the original cost of ownership of radio transmitters and receivers. This investment in radio systems is maintained in Accounts 2231.1 (Satellite and Earth Station Facilities) and 2231.2 (Other radio facilities.) 47 C.F.R. § 32.2231(a).

proposed to exclude what previously were the non-administrative components of Part 31 Accounts 671 (Operating Rents), 672 (Relief and Pensions) and 677 (Expenses Charged During Construction).[175]

49. We affirm our tentative conclusion that the administrative element contain Part 32 Accounts 6710[176] and 6720[177] because those accounts contain a comprehensive set of administrative expenses which are related to operating expenses and capital costs attributable to pole attachments.[178] Even though some expenses contained in these accounts are not attributable to pole attachments, the bulk of the expenses are relevant to plant investment.[179] It is not necessary to separate out all miscellaneous expenses from the accounts used. Notably, there are minimal pole related expenses reported in other accounts that are largely not pole related and, therefore, not included in our formula calculations. We do not require the removal of every non-pole related cost from every account nor do we require every pole attachment cost be pulled from extraneous accounts.[180] The LEC utility pole owner is compensated for the pole attachment's use of space on the pole by the use of the *Cable Formula* as required by the statute.[181] Cable operators and telecommunications carriers support the inclusion of Accounts 6710 and 6720.[182]

50. We do not adopt our tentative proposal to include Accounts 6110, 6120, 6534 and 6535.

[175] *Notice* at ¶ 33.

[176] Account 6710 includes a summary for reporting purposes of the contents of Accounts 6711 and 6712. (47 C.F.R. § 32.6710). Account 6711 includes: executive and planning costs incurred in formulating corporate policy and in providing overall administration and management. (47 C.F.R. § 32.6711). Account 6712 includes: costs incurred in developing and evaluating long-term courses of action for the future operations of the company, including performing corporate organization and integrated long-range planning, management studies, options and contingency plans and economic strategic analysis. (47 C.F.R. § 32.6712).

[177] Account 6720 includes a summary for reporting purposes of the contents of Accounts 6721 through 6728. (47 C.F.R. § 32.6720). Account 6720 is comprised of the accounts for accounting and finance (47 C.F.R. § 32.6721), external relations (47 C.F.R. § 32.6722), human resources (47 C.F.R. § 32.6723), information management (47 C.F.R. § 32.6724), legal (47 C.F.R. § 32.6725), procurement (47 C.F.R. § 32.6726), research and development (47 C.F.R. § 32.6727), and "other general and administrative" (47 C.F.R. § 32.6728).

[178] *See* 47 U.S.C. § 224(d)(1).

[179] *See* NCTA Comments at 32-35.

[180] *See 1977 Senate Report* at 19-22; *see also American Cablesystems of Florida, Ltd.*, 10 FCC Rcd 10934 (1995).

[181] 47 U.S.C. § 224(d)(1).

[182] *See, e.g.*, AT&T Comments at 20; GTE Comments at 10; NCTA Comments at 26-34; SBC Comments at 22; USTA Comments at 16.

Generally, LEC pole owners support the Commission's proposals for adoption of Part 32 and the inclusion of Accounts 6710, 6720, 6110, 6120, 6534 and 6535.[183] In contrast, cable operators assert that if Accounts 6110, 6120, 6534, 6535 are used, the attaching entity will be paying for the same expenses twice, once through make ready charges and again as part of the pole attachment rate.[184] The cable operator or telecommunications carrier compensates the pole owner for pole attachments through project specific costs in make-ready expenses[185] and through rates based on the *Cable Formula*.[186] Account 6110, Network Support Expenses, aggregates a number of different accounts that relate to general equipment cost and maintenance not applicable to other plant specific operations expenses.[187] Account 6120, General Support Expenses, aggregates a number of accounts that relate to expenses and costs not directly attributable to pole attachments, such as art work and computers.[188] Account 6534, Plant Operations Administration Expense, includes costs incurred in the general administration of plant operations that are not transferable to project specific construction and training accounts.[189] Account 6535, Engineering Expense, includes costs incurred in the general engineering of the LEC's telecommunications plant which are not directly chargeable to a specific project.[190] If costs are attributable to a pole attachment specific project, those expenses are recorded in accounts already included in the *Cable Formula*.

51. We affirm our conclusion not to include Part 32 Account 6231 in the calculations for the administrative element because that account reports expenses associated with radio systems [191] and is

[183]*See, e.g.*, AT&T Comments at 20; GTE Comments at 10; SBC Comments at 22; USTA Comments at 16, Reply at 9-10.

[184]*See, e.g.*, NCTA Comments at 32-35; *see also* Time Warner Comments at 25.

[185]*See, e.g.*, NCTA Comments at 32-35; Time Warner Comments at 25.

[186]*See* 47 U.S.C. § 224(d)(1); *see also, e.g.*, NCTA Comments at 32-35; Time Warner Comments at 25.

[187]*See* 47 C.F.R. § 32.6110. Account 6110 (Network Support Expenses) includes a summary for reporting purposes of the contents of Accounts 6112 through 6116. Account 6110 includes: motor vehicle expense (47 C.F.R. § 32.6112), aircraft expense (47 C.F.R. § 32.6113), special purpose vehicles expense (47 C.F.R. § 32.6114), garage work equipment expense (47 C.F.R. § 32.6115), other work equipment expense (47 C.F.R. § 32.6116).

[188]*See* 47 C.F.R. § 32.6120. Account 6120 (General Support Expenses) includes a summary for reporting purposes of the contents of Accounts 6121 through 6124. Account 6120 includes: land and building expense (47 C.F.R. § 32.6121), furniture and art work expense (47 C.F.R. § 32.6122), office equipment expense (47 C.F.R. § 32.6123), general purpose computers expense (47 C.F.R. § 32.6124).

[189]*See* 47 C.F.R. § 32.6534.

[190]*See* 47 C.F.R. § 32.6535.

[191]*See* 47 C.F.R. § 32.6211, § 32.2231.

unrelated to poles.[192] There was no opposition to the exclusion of Account 6231 from the administrative element calculations. We also affirm our proposal to exclude the non-administrative expenses previously charged to Part 31 Accounts 671, 672, and 677, except to the extent the expenses are include in Part 32 Accounts 6710 and 6720.[193]

52. The following formula is adopted to determine the administrative element of the carrying charge rate of the *Cable Formula* for LEC pole owners:

$$\begin{array}{c}\text{Administrative}\\ \text{Element}\end{array} = \frac{\text{Administrative and General (Accounts } 6710 + 6720\text{)}}{\begin{array}{c}\text{Gross Plant Investment}\\ \text{(Account 2001)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation}\\ \text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred Taxes, Plant}\\ \text{(Accounts 4100 \& 4340)}\end{array}}$$

2. The Maintenance Element

53. In the *Pole Attachment Order*, the Commission adopted procedures to identify and calculate the maintenance expenses for use in the carrying charge rate as a ratio of expenses included in the utility's pole maintenance account, to net pole investment.[194] For purposes of the calculation of the maintenance element, the denominator is the net pole investment which equals the sum of gross pole investment, minus accumulated depreciation related to poles, minus accumulated deferred income taxes related to poles.[195]

a. Pole Rental Expenses Paid to a Third Party by LEC Pole Owner

54. In the *Notice*[196] we proposed the following revised formula for the maintenance element[197] for LEC pole owners, to exclude pole rental expenses paid to third parties by the LEC pole owner, from the amount reported in Account 6411 (Poles Expense):

---

[192] *See* NCTA Comments at 32-35.

[193] *See, e.g.,* AT&T Comments at 20; GTE Comments at 10; NCTA Comments at 26-34; SBC Comments at 22; USTA Comments at 16.

[194] 2 FCC Rcd 4387 (1987).

[195] 2 FCC Rcd at 4387, 4402-04, Attachment B (1987).

[196] *Notice* at ¶¶ 33-34.

[197] In the *Pole Attachment Order*, 2 FCC Rcd 4387 (1987), the formula for the maintenance element included FCC Form M Part 31 Account 602.1. Account 602.1 was converted to Part 32 Account 6411. *See Part 32 Guidance Letter*, 5 FCC Rcd 3898 (1990).

$$\text{Maintenance Element} = \frac{\text{Account 6411} - \text{Rental Expense (Poles)}}{\text{Account 2411} - \text{Accumulated Depreciation (Poles)} - \text{Accumulated Deferred Income Taxes (Poles)}}$$

55. We affirm our tentative conclusion to exclude rental expenses from accounts that make up either the administrative or maintenance elements of the carrying charge rate of the *Cable Formula*.[198] Based on the record and current practice, we believe the most economically precise and equitable approach is not to include rents paid to third parties in either the administrative or maintenance element of the carrying charge rate for LECs. These expenses are itemized and reported on Account 6411, and can be verified and removed from the formula calculations.[199] The burden should not rest on an attaching entity to discover or determine whether rents are appropriate for inclusion in the carrying charge rate as some pole owners suggest. We disagree that the inclusion or exclusion of rental expenses should depend on what is contracted for in the rental agreement between the third party pole owner and the LEC "renter."[200]

56. The exclusion of pole rental expenses paid to a third party is necessary to avoid the attaching entity compensating the LEC pole owner for expenses related to the LEC pole owner's core business expenses rather than capital costs of providing pole attachments as required by Section 224(d)(1).[201] Account 6411 includes the rents paid by the LEC to electric utilities for the LEC's use of the electric utility's poles for the LEC's own core business. Cable operators and telecommunications carriers pay to LECs pole attachment rental fees to attach to LEC poles, and may also independently pay rental fees to the electric utility to attach to their poles. Inclusion of the LEC's rental fees paid to the electric utility in the *Cable Formula* would result in the cable operator or telecommunications carriers subsidizing the LEC's own pole rental fees and paying the electric utility twice.[202] We disagree that inclusion of pole rental expenses is appropriate because the costs are incurred in relation to plant administrative expenses.[203] We

[198] *Notice* at ¶¶ 33-34.

[199] *See* 47 C.F.R. § 32.6411; *Part 32 Guidance Letter*, 5 FCC Rcd 3898 (1990); *see also, e.g.*, NCTA Comments at 26-27, Reply at 33-34.

[200] *See, e.g.*, Ameritech Comments at 4-5, Reply at 3; Bell Atlantic/NYNEX Comments at 6. *Cf.* USTA Reply at 8.

[201] *See, e.g.*, NCTA Comments at 26-27 (inclusion of rents could result in attaching entity subsidizing the telephone company's pole rentals and paying the electric company rental fees twice), Reply at 33-34; Time Warner Comments at 26 (exclude rental expenses); USTA Reply at 8 (attaching entity should not have to determine when it is appropriate to include rental expenses in its rate); U S West Reply at 8 (appropriate to exclude to avoid double counting).

[202] *See, e.g.*, NCTA Comments at 26-27, Declaration of Patricia Kravtin at ¶ 18; Time Warner Comments at 26; USTA Reply at 8.

[203] *See, e.g.*, Bell Atlantic/NYNEX Comments at 6 (include pole rental expense in Account 6411 costs).

are not persuaded that the inclusion of these rents in pole attachment rate computations is appropriate just because it represents a business expense incurred by the LEC to conduct its core business.[204]

b. FERC Account 590

57. In the *Pole Attachment Order*, the Commission adopted the following formula to determine the maintenance element of the carrying charge rate for use by electric utility pole owners:[205]

$$\begin{array}{c}\text{Maintenance}\\ \text{Expense}\end{array} = \frac{\text{Account 593 (Maintenance of Overhead Lines)}}{\begin{bmatrix}\text{Investment in}\\ \\ \text{Accounts 364, 365, \& 369}\end{bmatrix} - \begin{bmatrix}\text{Depreciation in}\\ \\ \text{Accounts 364, 365, \& 369}\end{bmatrix} - \begin{bmatrix}\text{Deferred Income Taxes}\\ \text{Related to}\\ \text{Accounts 364, 365, \& 369}\end{bmatrix}}$$

58. In the *Notice*,[206] we sought comment on whether a portion of the expenses recorded in FERC Account 590 (Maintenance Supervision and Engineering)[207] should also be included in the numerator of this equation if the cost of labor and expenses reported in that account relates to poles. If so, we inquired what amount of those expenses should be allocated to the pole maintenance carrying charge. Electric utilities record the cost of labor and expenses incurred in the general supervision and direction of the distribution system maintenance in Account 590.[208] A portion of the amount in Account 590 may support supervision of the maintenance of the pole line investment. The amount in this account, however, also applies to distribution plant other than poles and conduit. If used, the amount from the account would have to be adjusted.[209] In the *Notice*, we tentatively concluded that some identifiable portion of the expenses recorded in Account 590 should be included in the maintenance element of the carrying charge rate of the *Cable Formula.*

59. As a result of our review of the record in this proceeding, we reject our tentative conclusion. We believe that any increased accuracy that would be derived from including the minute percentage of pole related expenses that may be included in Account 590, is outweighed by the complexity of arriving at an appropriate and equitable percentage of the expenses. The elements are not designed to be

[204] *See, e.g.,* Ameritech Comments at 4-5; Bell Atlantic/NYNEX Comments at 6 (include pole rental expense in Account 6411 costs).

[205] 2 FCC Rcd at 4387, 4402-03 (1987).

[206] *Notice* at ¶ 35.

[207] 18 C.F.R. Part 101.

[208] 18 C.F.R. Part 101, description of accounts; *see also* Carolina Power Comments at 52-54; Duquesne Light Comments at 30.

[209] *See, e.g.,* Carolina Power Comments at 52-54 (for poles), 71-72 (for conduit).

all inclusive nor are they intended to exclude all non-pole related expenses in the interest of simplicity.[210] Utility pole owners are adequately compensated for their costs of providing space in which an attaching entity can attach facilities necessary to support its cable or telecommunications services through the *Cable Formula* components.[211] The methodology used to arrive at a pole attachment rate should be simple and based preferably on publicly identifiable and verifiable data.[212] In our view, the existing formula for the maintenance element of the carrying charge rate achieves that objective.

60. Electric utility pole owners assert that Account 590 expenses are appropriate for inclusion in carrying charge rate factor of the *Cable Formula*.[213] Edison Electric/UTC suggests a factor of two percent of Account 590 would be appropriate,[214] while Ohio Edison contends that 22% of the expenses in Account 590 could be allocable to pole maintenance.[215] Sprint expressly supports the use of Account 590 data.[216] Cable operators contend that Account 590 is designed to cover maintenance costs that have little or no nexus to the pole network and attachment of communications facilities to such poles and that actual maintenance expenses associated with poles, conductors and services (drops) are already accounted for in other accounts.[217] Further, cable operators contend that the amount of return possible is not justified by the level of detail and calculation required.[218]

61. We disagree with electric utilities that Account 590 should be included in the carrying charge rate factor of the *Cable Formula* just because the expenses relate to the maintenance of a distribution system which may include poles.[219] The description of Account 590 advises that "direct field

---

[210] *1977 Senate Report; Telecable of Piedmont, Inc. v. Duke Power Co.*, 10 FCC Rcd 10898 (1995); *see also American Cablesystems of Florida, Ltd. v. Florida Power & Light Co.*, 10 FCC Rcd 10934 (1995).

[211] 47 U.S.C. § 224(d)(1).

[212] *First Report and Order*, 68 FCC 2d 1585 (1978); *Pole Attachment Order*, 2 FCC Rcd 4387 (1987); *see also American Cablesystems of Florida, Ltd. v. Florida Power & Light Co.*, 10 FCC Rcd 10934 (1995).

[213] *See* American Electric Comments at 66; Carolina Power Comments at 52-54, 71-72; Duquesne Light Comments at 30; Edison Electric/UTC Comments at 25-26; Ohio Edison Comments at 29; Union Electric Comments at 35.

[214] Edison Electric/UTC Comments at 26 (2% is appropriate).

[215] Ohio Edison Comments at 29 (22% of Account 590 should be allocable to pole maintenance).

[216] *See* Sprint Comments at 10.

[217] *See, e.g.,* NCTA Comments at 37; Time Warner Comments at 26.

[218] *See, e.g.,* NCTA Comments at 37; Time Warner Comments at 26.

[219] *See* American Electric Comments at 66; Carolina Power Comments at 52-54, 71-72; Duquesne Light

supervision of specific jobs shall be charged to the appropriate maintenance account." To the extent that pole owners are able to specifically identify and report maintenance costs related to poles on which there are pole attachments, those expenses should be included in Account 593 on which the maintenance element is currently based.[220] We are not persuaded that any residual expense related to poles that may be included in this account is significant.

3. The Depreciation Element

62. In the *Pole Attachment Order,*[221] the Commission adopted the following formula to determine the depreciation expense[222] for use in the *Cable Formula*:

$$\begin{array}{c}\text{Depreciation}\\ \text{Expense}\end{array} = \begin{array}{c}\text{Depreciation Rate}\\ \text{for Gross Pole}\\ \text{Investment}\end{array} \times \frac{\text{Gross Pole Investment}}{\text{Net Pole Investment}}$$

63. For the purpose of the formula calculations, net pole investment is identified as gross pole investment minus the depreciation reserve (also known as accumulated depreciation) related to poles minus accumulated deferred income taxes related to poles.[223] Under 47 C.F.R. Part 32, Section 32.22(a), LECs are required to provide their current and non-current deferred tax data in Accounts 4100 and 4340, respectively.[224] The formula for the net cost of a bare pole includes accumulated deferred taxes which are derived by adding Accounts 4100 and 4340. The sum of these two accounts is then multiplied by the ratio of gross pole investment to total gross plant investment to calculate the net deferred operating income taxes for poles.

Comments at 30; Edison Electric/UTC Comments at 25-26; Ohio Edison Comments at 29; Union Electric Comments at 35. *But see, e.g.,* NCTA Comments at 37-38.

[220] *See, e.g.,* NCTA Comments at 37; Time Warner Comments at 26. Account 593 also includes some non-pole related expenses, such as expenses for the cleaning of insulators and bushings, various functions in support of crossarms, the capital costs of which are factored out of the net cost of a bare pole as discussed elsewhere in this *Order*; *see also* 18 C.F.R. Part 101, Account 590, 593 description of accounts.

[221] 2 FCC Rcd at 4387, 4402-03, Attachment B (1987).

[222] 47 C.F.R. § 1.1404(g)(9).

[223] 2 FCC Rcd at 4387, 4402-03 (1987) Attachment B (for electric utilities and for LEC utilities). The Attachment further clarified that "[i]n using calculations using FERC Form. No. 1 data and FCC Form M data, we are treating deferred taxes as most state commissions do -- as a rate base deduction. If the state utility commission includes the reserve for deferred income taxes in the utility's capital structure at zero cost, we would not need to make any further adjustment, [as described at] ¶¶ 42-48 and note 16, *supra*."

[224] 47 C.F.R. § 32.22(a).

64. Some LEC pole owners assert that, because pole removal costs typically exceed gross salvage proceeds by a wide margin, negative net salvage values and, consequently, negative or unusually low pole attachment rates may occur late in a pole's useful life. For example, if each of the five carrying charge formula components equals 10%, the total carrying charge rate would be 50%. This rate would then be multiplied by net pole investment, expressed on a per pole basis as net cost of a bare pole, and the percentage of usable pole space occupied by a cable operator or telecommunications carrier, to determine the maximum just and reasonable rate per pole. Since the *Cable Formula* calculation involves the multiplication of these three factors, two of which would be positive and one negative, a negative rate could result if the LECs assertions proved true.

65. The *Cable Formula* methodology anticipates depreciation rates at levels sufficient to provide each utility pole owner the opportunity to recover its plant investment on a straight-line depreciation basis over the life of the associated plant. In the *Notice*,[225] we proposed to revise the depreciation element of the *Cable Formula*. We sought comment[226] on the scope of the problem outlined in the *SWB Petition*[227] and inquired as to the number of jurisdictions where accumulated depreciation balances currently exceed gross pole investment, or may in the near future.[228] In instances where commenters believe that a modification of the pole attachment formula is necessary, we sought comment on appropriate adjustments and the circumstances in which the adjustment should be made.[229] We sought comment to determine whether net salvage value is appropriate to include in the depreciation rate or whether the application of the depreciation rate formula leads to negative net pole investment results.[230]

66. In the *Notice*,[231] we also sought comment on whether, due to the frequency with which accumulated depreciation balances exceed gross pole investment, a modification of the *Cable Formula* is necessary. Four LEC pole owners report that they currently have negative pole values due to the results of calculations using negative net pole salvage values.[232] Two other LEC pole owners predict they may

[225] *See Notice* at ¶¶ 15-16.

[226] *Notice* at ¶ 21.

[227] Southwestern Bell Telephone Company, Computation of Rates for Attachment of Cable Television Hardware to Utility Poles, Petition for Clarification or in the Alternative, a Waiver, AAD 94-125 (filed Aug. 26, 1994) (*SWB Petition*).

[228] *Notice* at ¶¶ 23.

[229] *Notice* at ¶¶ 22.

[230] *Notice* at ¶¶ 24.

[231] *Notice* at ¶¶ 21-28.

[232] *See, e.g.,* Bell Atlantic/NYNEX Comments at 3; SBC Comments at 11; Sprint Comments at 5-8 (Sprint

experience negative net pole values in the future.[233] Electric utilities report their costs of removal by different accounting methods than LECs and do not experience negative results.[234] Cable operators and some telecommunications carriers assert the reports of negative pole value are either anomalies of the accounting practices used, or are mathematically impossible.[235]

67. We find that there is some merit in all of the comments received. The problem arises from the net pole investment formula itself, under which:

$$\begin{array}{c} \text{NetPole} \\ \text{Investment} \end{array} = \begin{array}{c} \text{Gross Pole} \\ \text{Investment} \\ \text{(Account 2411)} \end{array} - \begin{array}{c} \text{Accumulated} \\ \text{Depreciation (Poles)} \\ \text{(Account 3100)} \end{array} - \begin{array}{c} \text{Accumulated Deferred} \\ \text{Income Taxes (Poles)} \\ \text{(Accounts 4100 \& 4340)} \end{array}$$

For LECs, the Accumulated Depreciation balance includes both the depreciation attributable to Gross Pole Investment *and* depreciation attributable to removal costs. However, Account 2411 does *not* include removal costs. Instead, removal costs are subtracted from gross salvage proceeds to arrive at future net salvage value. Therefore, the Accumulated Depreciation balance will ultimately exceed Gross Pole Investment, leading to negative net pole valuations. As a general matter, these atypical results are also fueled by the materiality of pole removal costs. For most telecommunication asset classes, removal costs represent a small percentage of gross investment and are usually less than gross salvage proceeds. However, poles are an anomaly in this regard. Future Net Salvage values average -73%, meaning that removal costs dwarf gross salvage proceeds, and represent a large percentage of Gross Pole Investment. Applying the depreciation of removal costs to Gross Pole Investment, therefore, accelerates the recovery period of Gross Pole Investment by over 40%.

68. As a remedy, some commenters suggested setting a minimum value for net pole investment at the last positive valuation to occur under our current formula.[236] Although we agree that this would preclude negative results, it would not cure the fundamental mismatch between the components of the Gross Pole Investment and Accumulated Depreciation calculations. Moreover, investment returns based on the difference between Gross Pole Investment and Accumulated Depreciation as defined presently are understated to the extent that removal cost depreciation is reflected in the Accumulated Depreciation balance. This inequity would persist if last positive valuations were used. Finally, last positive valuations would vary among operators and lead to inconsistent results.

Operating Companies have now); U S West Comments at 6.

[233] *See* Ameritech Comments at 2; GTE Comments at 4.

[234] *See, e.g.*, American Electric Comments at 71.

[235] *See, e.g.*, NCTA Reply at 26-29; MCI Comments at 33-37; TCI Comments at 22; Time Warner Comments at 23.

[236] *See, e.g.*, NCTA Reply at 28-29.

69. Instead, we will eliminate the *cause* of the negative results. Specifically, when the Accumulated Depreciation attributable to removal costs is isolated as an offset to gross removal costs under the future net salvage calculation, negative results are eliminated. This allows a proper matching of depreciation and corresponding sources, and provides an accurate basis for calculating investment returns. Account 3100, as used in the *Cable Formula*, is redefined to include only that portion of Account 3100 which arises from the depreciation of Account 2411. The remaining component of Account 3100, accumulated depreciation for removal costs, is netted separately under the future net salvage calculation. The total depreciation recovery remains unchanged, but the risk of negative carrying charge components has been eliminated. The LECs recovery basis is now comparable to that of electric utility pole owners.

70. Consequently, for the purposes of *all* affected formulas, we redefine Net Pole Investment as:

$$\begin{array}{c}\text{Net Pole}\\\text{Investment}\end{array} = \begin{array}{c}\text{Gross Pole}\\\text{Investment}\\\text{(Account 2411)}\end{array} - \begin{array}{c}\text{Accumulated}\\\text{Depreciation (Poles)}\\\text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred}\\\text{Income Taxes (Poles)}\\\text{(Accounts 4100 \& 4340)}\end{array}$$

where Accumulated Depreciation (Poles) includes *only* that portion of Account 3100 which arises from the depreciation of Account 2411. The portion of Accumulated Depreciation (Poles) attributable to removal costs shall be treated as an offset to gross removal costs when calculating future net salvage value.

4. The Taxes Element

71. In the *Notice*,[237] we sought comment on whether the taxes element of the carrying charge rate of the formula used for LEC pole owners should reflect certain tax-related accounts. We also proposed that changes from Part 31 to Part 32 accounting for LEC pole owners should be reflected under the following formula:

$$\begin{array}{c}\text{Tax}\\\text{Element}\end{array} = \frac{\text{Operating Taxes (Account 7200)}}{\begin{array}{c}\text{Gross Plant Investment}\\\text{(Account 2001)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation}\\\text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred Taxes}\\\text{(Plant, Accounts 4100 \& 4340)}\end{array}}$$

72. We believe the proposed accounts and methodology for the taxes element of the carrying charge rate provide utility pole owners with appropriate compensation when used under the *Cable Formula*.[238] Although a one-to-one matching of tax elements from Part 31 to Part 32 may not be achievable in all instances, we believe the proposed tax element formula will provide reasonable results in

[237] *Notice* at ¶ 36.

[238] *Notice*, 12 FCC Rcd at 7449, Appendix B.

an expeditious manner.[239] Basing the tax element of the carrying charge rate on pole investment, rather than plant investment as proposed by utility pole owners,[240] may produce results decidedly different from the actual tax experience of pole owners and are subject to manipulation. Similarly, the application of statutory tax rates instead of tax rates based on actual individual experience are likely to produce overstated tax carrying charge rate that would result in artificially higher pole attachment rates.

73. We affirm the use of our proposed formula. Our policy in applying the *Cable Formula* does not eliminate all non-pole related expenses from all accounts used in the carrying charge rate.[241] We are not required to disaggregate accounts to eliminate possible non-pole related investments or expenses, nor are we required to scour all utility accounts for every dollar that may benefit a pole attachment.[242] We do not believe the statutory Federal income tax rate, rather than actual taxes paid, should be used in calculating the taxes element of the carrying charge rate factor of the *Cable Formula* because the actual taxes paid are readily available from the utility pole owners' regulatory agency data.[243]

5. The Rate of Return Element

74. The rate of return element[244] is currently taken from the rate of return authorized for the utilities' intrastate services. In the *Notice,* we noted that this policy implicitly assumes that the states will continue to regulate utility rates on a rate of return basis, when in fact many states are moving away from that method of regulation and have adopted incentive-based regulation.[245] We tentatively concluded that in such cases the authorized intrastate rates of return will not reflect the utilities' costs of capital.[246]

75. The Commission has adopted an annual rate of return for the interstate access services of LECs of 11.25%.[247] In the *Notice,* we sought comment on whether 11.25% should be used as the rate of

[239] *See, e.g.*, AT&T Reply at 25; NCTA Comments at 26-27.

[240] *See, e.g.*, Bell Atlantic/NYNEX Comments at 7.

[241] *American Cablesystems of Florida,* 10 FCC Rcd 10934, at ¶ 10. *But see* American Electric Comments at 58-67; Carolina Power Comments at 56.

[242] *See 1977 Senate Report* at 19-20*; American Cablesystems of Florida, Ltd.,* 10 FCC Rcd 10934; *see also* NCTA Comments at 26-34; Time Warner Comments at 24-26.

[243] *See* Bell Atlantic/NYNEX Comments at 7.

[244] *See* 47 C.F.R. § 1.1404(g)(10).

[245] *Notice* at ¶ 37.

[246] *See Notice* at ¶ 37; *see also* 47 U.S.C. § 224(d)(1).

[247] *See Represcibing the Authorized Rate of Return for Interstate Services of Local Exchange Carriers,* CC

return when calculating the carrying charge rate factor of the *Cable Formula*, for utilities in states that no longer regulate that utility on a rate of return basis.[248] In the *Notice*,[249] we proposed the following as the return element of the carrying charge rate for use in the *Cable Formula*:

$$\begin{matrix}\text{Return}\\ \text{Element}\end{matrix} = \begin{matrix}\text{Applicable}\\ \text{Rate of Return}\end{matrix}$$

76. We affirm our tentative conclusion to continue the use of the rate of return authorized by the state for intrastate services of the utility, when available.[250] Commenters generally agree that the rate of return set by the Commission for LECs, as modified from time to time, is a reasonable default rate of return for use in the *Cable Formula* when an actual rate of return is not prescribed by the state.[251] NCTA points out, however, that, if the utility's actual realized rate of return is lower than the default, it would be inequitable to allow it a higher rate of return than its actual rate.[252] We believe that the use of the default rate of return is an equitable solution, in those instances when a state has not prescribed a rate of return for a utility covering the period of time in which rates were in dispute. We adopt as the default rate of return, the rate of return set by the Commission for LECs, covering the appropriate period, as it is modified from time to time.[253] We believe this serves our policy of using default rates to expedite the *Cable Formula* calculations.

VI. FORMULA FOR DETERMINING ATTACHMENT RATES FOR CONDUITS

A. Background

77. Conduits are structures that provide physical protection for cables and allow new cables to be added inexpensively along a route, without having to dig up the landscape, streets and other structures in

Docket No. 89-624, 5 FCC Rcd 7507 (1990).

[248]*Notice* at ¶ 37.

[249]*Notice*, 12 FCC Rcd at 7449, Appendix A.

[250]*See* 47 C.F.R. § 1.1404(g)(10)*; see also Alabama Power*, 773 F.2d at 371-72.

[251]*See, e.g.*, American Electric Comments at 69; Bell Atlantic/NYNEX Comments at 2, 5; ConEd Comments at 4-5, 14; GTE Comments at 11; MCI Comments at 20-21; NCTA Comments at 38; SBC Comments at 22-23; Sprint Comments at 10; Union Electric Comments at 37.

[252]NCTA Comments at 38.

[253]The current rate of return of 11.25% is subject to revision by the Commission. *See* Common Carrier Bureau Sets Pleading Schedule in Preliminary Rate of Return Inquiry, 11 FCC Rcd 3651 (1996) and 47 C.F.R. § 65.101; *see also* AT&T Comments at 20 (citing *Local Competition Order*, 11 FCC Rcd 15499, 15856, ¶ 702).

the community each time a new cable is installed. A collection of conduits, together with their supporting infrastructure, constitutes a conduit system.[254] A conduit consists of one or more ducts, which are the enclosures that carry the cables.[255] Often, when cable system or telecommunications carriers' cables are placed in a duct, three or more inner ducts are inserted into the duct allowing "one duct to be treated more like conduit."[256] Section 224 provides that for conduit, the capacity of the conduit is the equivalent of usable space in the pole context.[257]

78. Congress authorized the Commission to regulate rates, terms, and conditions for pole attachments in ducts and conduits under Section 224 which states:

> . . . a rate is just and reasonable if it assures a utility the recovery of not less than the additional costs of providing pole attachments, nor more than an amount determined by multiplying the percentage of the . . . total duct or conduit capacity, which is occupied by the pole attachment, by the sum of the operating expenses and actual capital costs of the utility attributable to the entire . . . duct [or] conduit.[258]

The *1977 Senate Report* outlined Congressional intent regarding the methodology the Commission should apply when determining whether a rate was just and reasonable for pole attachments on poles and in ducts, conduit and rights-of-way.[259] It was not until 1996, however, that the Commission had before it a complaint about rates charged by a utility for attachments in a conduit.[260]

79. In the *Notice*,[261] we sought comment on application to conduits of the attachment formula used to calculate the maximum rate for poles, and on several issues relating to how to determine the percentage of capacity occupied by an attachment:[262] how to identify the total capacity and costs

---

[254] *See NESC* § 2; *see also* American Electric Comments at 84.

[255] *NESC* § 2.

[256] Edison Electric/UTC Comments at 22 n. 7.

[257] *See* 47 U.S.C. § 224(d)(1).

[258] 47 U.S.C. § 224 (d)(1).

[259] *1977 Senate Report* at 19-20.

[260] *Multimedia Cablevision v. SWB*, CS Docket No. 96-181, 11 FCC Rcd 11202 (1996) ("*Multimedia Cablevision*").

[261] *Notice* at ¶¶ 38–46.

[262] 47 U.S.C. § 224(d)(1).

attributable to the conduit, and whether conduit owned by an electric utility is sufficiently different from conduit owned by a LEC or other utility to warrant special treatment. The conduit methodology proposed in the *Notice* to determine the maximum just and reasonable rate per attachment is represented as follows:[263]

$$\begin{matrix}\text{Maximum}\\\text{Rate}\end{matrix} = \frac{1\,\text{Duct}}{(\text{Avg. No. of Ducts - Adjustments for Reserved Ducts})} \times \frac{1}{2} \times \begin{matrix}\text{Net Linear}\\\text{Cost of Conduit}\end{matrix} \times \begin{matrix}\text{Carrying}\\\text{Charge}\\\text{Rate}\end{matrix}$$

80. This formula follows the same methodology that we use for determining just and reasonable rates for pole attachments on poles,[264] and uses a half-duct rebuttable presumption for capacity used by a pole attachment in a conduit.[265] The Commission first applied this adaptation, based on the unique characteristics of duct and conduit systems, in *Multimedia Cablevision, Inc. v. Southwestern Bell Telephone,* where the Commission concluded that it was a simple and efficient mechanism for establishing a conduit rate consistent with Section 224.[266]

$$\begin{matrix}\text{Maximum}\\\text{Rate}\end{matrix} = \underbrace{\left[\frac{1}{\text{Number of Ducts}} \times \frac{1\,\text{Duct}}{\text{No. of Inner Ducts}}\right]}_{\text{(Percentage of Conduit Capacity)}} \times \underbrace{\left[\begin{matrix}\text{No. of}\\\text{Ducts}\end{matrix} \times \frac{\text{Net Conduit Investment}}{\text{System Duct Length}}\right]}_{\text{(Net Linear Cost of a Conduit)}} \times \begin{matrix}\text{Carrying}\\\text{Charge Rate}\end{matrix}$$

B. Discussion

1. Conduit Formula Methodology

82. Just as we use the entire pole inventory for establishing a rate for pole attachments to poles, we believe it is appropriate to use system-wide data for establishing the maximum rate for conduit. Some electric utilities argue that, due to disparities in cost between urban and suburban conduit, using system-wide costs will not provide adequate compensation.[267] We note, however, that the electric utilities that raise the issue have themselves proposed calculating the carrying charges on a system-wide basis.[268]

---

[263] *Notice*, 12 FCC Rcd 7449 at Appendix C.

[264] *Notice* at ¶¶ 38-42.

[265] *See Greater Media, Inc., et al. v New England Telephone and Telegraph Co.,* No. DPU 91-218 (Mass. Dep't Pub Utils. April 17, 1992), applied in *Multimedia Cablevision*, 11 FCC Rcd 11202 (1996).

[266] *Multimedia Cablevision*, 11 FCC Rcd 11202 (1996).

[267] *See, e.g.*, Carolina Power Comments at 66; Ohio Edison Comments at 35.

[268] *See, e.g.*, Carolina Power Comments at 68–75; NCTA Reply at 48-50.

Similarly, as has been pointed out by Time-Warner and NCTA, calculating the cost of the conduit on a system-wide, or averaging, basis will adequately compensate the utilities.[269]

83. We are not persuaded by the electric utilities' contentions that they lack the detailed information necessary to apply the proposed formula.[270] They assert that use of specific FERC accounts is inconsistent among utilities.[271] Necessary figures are available in underlying records filed to support claims in sworn FERC submissions, and only in rare instances would a utility lack detailed information because it has no records.[272] Where such records do not exist, other sources of information may be used.[273] Electric utilities have demonstrated their ability to calculate a rate by applying the formula.[274] Although the conduits which comprise a conduit system may vary widely from urban to suburban or rural locales,[275] we will use the system-wide historical cost of the conduit in the formula.

2. Conduit Physical Characteristics

84. In the *Notice,* we asked whether there are physical differences between conduit owned and used by electrical or other utilities and conduit owned by cable systems or telecommunications carriers that would affect the rates for attachment to conduits.[276] We hypothesized that there would be differences related to conduit construction, maintenance and safety. We asked whether these differences should affect the rate for these facilities.[277]

---

[269]Time Warner Reply at 10–11; NCTA Reply at 49, 55.

[270]*See, e.g.,* American Electric Comments at 80-96, Reply at 40-41; Carolina Power Reply at 38-39; ConEd Comments at 6; Edison Electric/UTC Comments at 19-20; Ohio Edison Comments at 36; Union Electric Comments at 9, 11.

[271]*See, e.g.,* Carolina Power Comments at 65; Edison Electric/UTC Comments at 17-18.

[272]*See, e.g.,* MCI Reply at 44-45; NCTA Reply at 48.

[273]See, e.g., NCTA Reply at 49 (citing *Capital Cities Cable, Inc. v. Mountain States Telephone and Telegraph Co.*, File Nos. PA-81-0031, PA-81-0039, PA-82-0051, Mimeo 84786 at 4 (June 29, 1984*); Teleprompter Corp. v. Washington Water Power Co.*, 50 R. R. 2d 54 (1981)).

[274]*See, e.g.,* Carolina Power Comments at 68-75.

[275]*See, e.g.,* Carolina Power Comments at 62, 65-75; Duquesne Light Comments at 7; NCTA Comments at 40; Ohio Edison Comments at 43; Time Warner Comments at 27.

[276]*Notice* at ¶¶ 38–46.

[277]*Notice* at ¶ 36.

85. Some electric utilities comment that such differences do exist and should have an impact on the rate.[278] Specifically, they assert that electric conduits have safety and reliability considerations that warrant special caution due to potential dangers to untrained personnel, electric equipment, and high voltage requirements and that such concerns require special procedures and precautions.[279] They argue that these necessary precautions translate into additional costs and, therefore, impact just and reasonable rates.[280] These costs, however, are currently reflected in the rates. Infrastructure investment required to assure safety and reliability is captured in the accounts used to calculate the net book value of the respective types of conduit. Special precautions related to placement of communications cables in conduit are included in make-ready costs. All special precautions taken in maintenance of the system are reflected in the maintenance element of the carrying charge rate.

3. Factors of the Conduit Formula

86. The first factor of the formula, Conduit Capacity, is determined using the following variables:

"No. of Inner Ducts" is the number of inner ducts placed in the duct. If there are no inner ducts the value would be presumed to be two, reflecting the rebuttable presumption that not more than half of a duct is occupied.

"No. of Ducts" is the total number of ducts in the conduit system. This number does not include collapsed or otherwise damaged ducts that are not repairable. In general, this would be presumed to be the average number of ducts per conduit for the system.

87. The second factor of the formula, Net Linear Cost of Conduit, is determined using the following additional variables:

"Net Conduit Investment" is gross conduit investment less the accumulated depreciation and accumulated deferred taxes.

"System Duct Length" is the sum of the length of all ducts in the system minus the length of collapsed ducts and the length of ducts that for other reasons are physically unable to contain cable. The System Duct Length may be arrived at in one of three ways: First, it may be obtained from available records. Second, the length of the conduit in the system may be multiplied by an estimated average number of ducts per

---

[278] *See, e.g.*, Carolina Power Comments at 61, Reply at 38; ConEd Comments at 3; Edison Electric/ UTC Comments at 18-19; Dayton Power and Light Comments at 3; Public Service Co. of New Mexico at 5.

[279] *Notice* at ¶ 43.

[280] *See, e.g.*, Carolina Power Reply at 38; ConEd Comments at 3; Edison Electric/ UTC Comments at 18-19; Union Electric Comments at 11.

conduit. Third, the length of all ducts in the system is the sum of the products of the length of each conduit times the number of ducts in that conduit.[281]

88. Calculation of the maximum rate may be simplified by using the presumptions and using the Net Linear Cost of a Conduit for the second term in the formula. The formula then is, essentially, our proposed formula:

$$\begin{array}{c}\text{Maximum Rate} \\ \text{(System - Wide)}\end{array} = \underbrace{\frac{1/2 \quad \text{Duct}}{\text{Avg. No. of Ducts}}}_{\substack{\text{[Percentage of} \\ \text{Conduit Capacity]}}} \times \underbrace{\frac{\text{Net Conduit Investment}}{\text{System Conduit Length}}}_{\substack{\text{[Net Linear Cost} \\ \text{of a Conduit]}}} \times \begin{array}{c}\text{Carrying} \\ \text{Charge Rate}\end{array}$$

We discuss in greater detail below each of the factors within the formula.

a. Percentage of Total Capacity Occupied

i. Total Duct or Conduit Capacity

89. The total capacity of a duct or conduit is the entire volume of available capacity in the conduit system.[282] All costs associated with the construction of the conduit system are considered in determining the cost of this total capacity.[283] In the *Notice*, we sought comment on how to allocate capacity for various uses in a conduit,[284] and whether a utility may eliminate some of its conduit capacity from the total capacity as used in the formula, by reserving some capacity for use for maintenance, future business needs, or for space set-aside for use by a state or local government.[285] A utility may designate a maintenance duct so that if a cable in another duct fails, a temporary cable may be placed in the maintenance duct and spliced into the damaged cable.[286] A duct so designated is usable in the event it is

---

[281]To simplify calculation the Net Linear Cost of Conduit for the system may be used in lieu of the product of the No. of Ducts and the Net Linear Cost of a Duct. The Net Linear Cost of Conduit is the Net Conduit Investment divided by the System Conduit Length.

[282]*See, e.g.*, Carolina Power Comments at 75; NCTA Reply at 52-54.

[283]This is a departure from our position in the *Telecommunications Report and Order*, in which we concluded that a certain portion of construction costs might not be associated with the system's capacity. *Telecommunications Report and Order* at ¶ 110. Based on the expanded record and *Petitions for Reconsideration and/or Clarification of the Telecommunications Report and Order*, we now believe that all costs associated with the construction of the conduit system are used in creating the system's capacity and are properly considered in the cost of that capacity.

[284]*Notice* at ¶¶ 38–46.

[285]*Notice* at ¶ 45; *see also Local Competition Order* at ¶¶ 1165-1170.

[286]*See, e.g.*, AT&T Comments at 23; Carolina Power Comments at 63; Duquesne Light Comments at 7–8; Ohio

needed and, therefore, is part of the conduit capacity. Municipal ducts are those that may be allocated for the use of the local government as a condition in a franchise, license, right-of-way or other agreement.[287] Where a duct is required by the municipality to be set aside for potential future use, in the nature of consideration as a condition for a license, franchise, or permit, the costs attributable to that unused capacity are part of the total cost of the conduit. The utility is compensated for those costs as part of its net conduit investment and/or in the carrying charge rate. Ducts may be reserved, or kept unused to be available to the utility for expansion of its core business services.[288]

90. The question of reducing the amount of total capacity of a duct or conduit based on some theoretical or potential need, unduly complicates the conduit formula methodology.[289] The clear language of the statute dictates that the amount of "total duct or conduit capacity" is to be used when calculating a percentage of capacity occupied by a pole attachment. We will not allow capacity designated for maintenance, future business plans, or municipal set-asides to be subtracted from the total duct or conduit capacity.[290] The record supports our finding that capacity in a duct or conduit that is usable for any of these purposes is part of the "total duct or conduit capacity."[291] A methodology which attempts to account for any possible variations would require substantial oversight and regulation to prevent abuses or over recovery. Such regulation and complexity would be contrary to the clear language of the statute.[292]

91. Ducts which have collapsed or are otherwise damaged and are no longer available for pole

---

Edison Comments at 35; SBC Comments at 30–31.

[287]*See, e.g.,* SBC Comments at 32 (imposed as condition of granting right-of-way).

[288]*See* ConEd Comments at 9–11; Duquesne Light Comments at 8; Ohio Edison Comments at 35.

[289]*1977 Senate Report*; 47 U.S.C. § 224(d)(1); *see also,* NCTA Comments at 43-44.

[290]This is also a departure from our position in the *Telecommunications Report and Order*, in which we said such reserved capacity would be designated as "unusable space" for purposes of calculating an unusable space factor. *Telecommunications Report and Order* at ¶ 110. Based on the expanded record and *Petitions for Reconsideration and/or Clarification* of the *Telecommunications Report and Order,* we now believe there is no unusable capacity in a conduit system. For whatever reason space may be reserved or designated for special uses and regardless of who may benefit from those uses, the space is capable of being used, and it remains part of the total capacity of the duct or conduit.

[291]47 U.S.C. § 224(d)(1). *See, e.g.,* AT&T Reply at 29 (municipal set aside is often put to commercial use); NCTA Comments at 43-44 (generally, dedicated ducts are not reserved for exclusive use by municipality), Reply at 51-54 (duct used by any party is usable, identity of the party is irrelevant to the duct's usability); Time Warner Comments at 28 (maintenance ducts should be considered usable).

[292]*See 1977 Senate Report* at 19-20; 1996 Act, Preamble, *Conf. Rpt.* at 113.

attachments should not be included in the capacity of a conduit or duct.[293] Some of these ducts can be repaired.[294] Ducts that cannot be restored no longer provide capacity to the conduit and, by definition, do not constitute ducts.[295]

ii. Occupied Capacity, the Half-Duct Presumption

92. Presumptions are used in the *Cable Formula* to expedite the calculations of a just and reasonable rate so that complicated surveys, accounting and calculations may be avoided.[296] We proposed and sought comment on a methodology that presumes rebuttably that an attachment in a conduit occupies one half of a duct, and invited additional proposals to make the methodology simple and administratively efficient.[297]

93. We retain the rebuttable presumption adopted in *Multimedia Cablevision* that an attacher occupies one half of a duct, and no more. There we accepted the findings of the Massachusetts Department of Public Utilities that a cable system attachment occupies only one-half of a duct, does not preclude the use of the other half of the duct, and that, therefore, the cable system should not be charged for the use of the entire duct.[298] The record supports the retention of this presumption.[299]

94. Some electric utilities assert, however, that an electric supply cable cannot share a duct with a communications cable, and, therefore, from the electric utility point of view, the communications cable occupies the entire duct.[300] Some of these utilities also point out that for certain electric supply cables, minimum spacing requirements do not permit a communications cable in an adjacent duct, and, therefore, from their point of view, the communications cable occupies the adjacent ducts as well.[301] The

[293] *See, e.g.*, NCTA CS Dkt. No. 97-151 Comments at 25-26; SBC Comments at 72–73.

[294] *Greater Media* at ¶ 69.

[295] *NESC* § 2.

[296] *Second Report and Order*, 72 FCC 2d 59 (1979); *see also*, NCTA Reply at 46-47.

[297] *Notice* at ¶¶ 38–46.

[298] *Id.*, (referencing *Greater Media*, at ¶¶ 74-75).

[299] *See, e.g.*, Ameritech Comments at 7, Reply at 6; GTE Comments at 16, Reply at 17; SBC Reply at 14-15; USTA Comments at 20-22, Reply at 45; NCTA Comments at 40.

[300] *See, e.g.*, American Electric Comments at 85–87; ConEd Comments at 5–6; Duquesne Light Comments at 8; Edison Electric/UTC Comments at 20–21 .

[301] *NESC*, Rule 341A6 (1997 Ed.). *See* Edison Electric/UTC Comments at 21; Carolina Power Comments at 75.

situation is somewhat analogous to the safety space on a pole although it does involve a NESC prescribed exclusion zone around the electric supply cable. Electric utilities do not dispute that the capacity is usable, but argue that the full capacity of the duct is occupied by the communications cable because the electric utility is prevented from using that capacity by the NESC.[302] Communications cables may, and often do, share a duct.[303] The NESC requires that, where electric supply cables share a duct with communications cables, the cables be maintained by the utility.[304] It cannot be said, therefore, that any given communications cable occupies a whole duct. If the electric supply cable excludes other cables from the duct it occupies, it is that electric supply cable that occupies the entire duct, not the communications cables it excludes. Similarly, if the electric supply cable cannot tolerate communications cables in adjacent ducts, then the electric utility's supply cable effectively occupies those adjacent ducts not the communications cable. Conversely, if the electric supply cable cannot be placed in a duct because the duct is partially occupied by a communications cable, the reason is that the duct contains less available capacity than the electric supply cable requires. The capacity is available to other communications cables and is, therefore, not occupied.

95. Some cable operators assert that even the application of the half-duct methodology will result in rates that are unreasonably high in light of current inner-duct technology.[305] The term "inner-duct" generally refers to small diameter (1" or 1½") pipe or tubing placed inside a conventional duct to allow the installation of multiple wires or cables.[306] Use of inner-duct is a common practice. Some electric utilities recommend that we require the first attacher in a previously unoccupied duct to install inner-duct.[307] The cost of the inner-duct would, presumably, be considered a make-ready cost.[308] Ameritech urges that a presumption of less than one half of a duct would reflect what is possible, but not what is currently in place and what is practical under existing conditions.[309] We will not require installation of inner-duct. The half-duct presumption is rebuttable, and the presence of inner-duct is adequate rebuttal. We have made direct provision in the formula for that contingency. Where inner-duct is installed, either by the attacher or in a previous installation, the maximum rate will be reduced in proportion to the fraction of the duct occupied.

[302] *See, e.g.*, ConEd Comments at 5–6; Duquesne Light Comments at 8; Edison Electric/UTC Comments at 20–21.

[303] *See* ConEd Comments at 9; Duquesne Light Comments at 14.

[304] Edison Electric/UTC Comments at 20; Duquesne Light Comments at 8; MCI Reply at 42.

[305] *See, e.g.*, NCTA Comments at 42; TCI Comments at 16; Time Warner Comments at 28.

[306] MCI Comments at 25; *see also* Edison Electric/UTC Comments at 22.

[307] *See, e.g.*, ConEd Comments at 7–9; Duquesne Light Comments at 14; Edison Electric/UTC Comments at 22.

[308] ConEd Comments at 5–7.

[309] *See* Ameritech Reply at 6; *see also*, Bell Atlantic/NYNEX Reply at 15; NCTA Reply at 42-43.

That fraction will be one divided by the number of inner-ducts in the duct, so that a default presumption of capacity occupied is one-half duct, or the actual percentage of capacity occupied.

4. Net Linear Cost of Conduit

96. As indicated in the *Notice*, in the conduit context, we use the net linear cost of the conduit, as compared to the net cost of a bare pole, as one factor within the formula for determining the rate. The *Notice* presumed, without discussion and without specifically seeking comment, that utilities would be capable of determining this figure. As the net cost of a bare pole reflects the total system investment for the above ground pole attachment infrastructure, to arrive at a system investment for use in the conduit formula we identify the net linear cost of the conduit system. To accomplish this, the utility must first establish the Net Conduit Investment as discussed below.

a. Net Conduit Investment

97. The formula requires the determination of the utility's net linear cost of its conduit system. The Net Conduit Investment is calculated as follows:

$$\begin{array}{c} \text{Net Conduit} \\ \text{Investment} \end{array} = \begin{array}{c} \text{Gross Conduit Investment} \\ \text{(ARMIS Account 2441/} \\ \text{FERC Account 366)} \end{array} - \begin{array}{c} \text{Accumulated Depreciation} \\ \text{(Conduit)} \end{array} - \begin{array}{c} \text{Accumulated Deferred Taxes} \\ \text{(Conduit)} \end{array}$$

98. Gross Conduit Investment for the LEC consists of Part 32 Account 2441.[310] For the electric utility, Gross Conduit Investment is reflected in FERC Part 101 Account 366.[311] For LECs, Accumulated Depreciation (Conduit) represents the share of ARMIS Account 3100 that corresponds to Account 2441.[312] For electric utilities, Accumulated Depreciation (Conduit) represents the share of FERC Account 108 that corresponds to Gross Conduit Investment valuations included in Account 366.[313]

99. In the *Notice*[314] we proposed a formula for the calculation of accumulated deferred income taxes for conduit. The formula is shown as:[315]

---

[310] 47 U.S.C. § 32.2441.

[311] *See* 18 C.F.R. Part 101 (stating the accounts associated with the conduit attachment formula for electric utilities); *see also* 47 C.F.R. Part 32 (stating accounts associated with the conduit formula for LECs.

[312] *Part 32 Guidance Letter,* 5 FCC Rcd 3898 (1990). *See* ARMIS Report 43-02, row 0470.

[313] 18 C.F.R. Part 101.

[314] 12 FCC Rcd 7449 (1997) at Appendix C.

[315] For regulatory accounts to be used in the formulas, *see* Appendix C-3 and C-4 for LEC and electric utility

$$\text{Accumulated Deferred Income Taxes (Conduit)} = \frac{\text{Gross Conduit Investment}}{\text{Total Gross Plant}} \times \text{Total Accumulated Deferred Income Taxes}$$

100. Total Accumulated Deferred Income Taxes for electric utilities are based on FERC Account 190.[316] However, LEC conduit owners object to this formula on the basis that the actual amount of Accumulated Deferred Income Taxes for conduit is available directly from the LEC's books.[317] BellSouth maintains that because it is required to keep separate and accurate records of accumulated deferred income taxes for poles and conduit, our formula will improperly introduce non-conduit related deferred taxes into rate calculations.[318] NCTA argues that LECs should not use accumulated deferred income taxes figures taken from the LEC's books because the information is not publicly available.[319]

101. The *Pole Attachment Order* did not specifically require the use of proration as a method to be used in the calculation of the net costs of a bare pole,[320] which we apply in this context for conduit, and only noted that accumulated deferred income taxes were to be used in calculations.[321] Our goal has always been to adopt a formula which set the maximum rate using publicly available data, in a fair and expeditious manner.[322] We also have a policy against requiring additional accounting procedures so long as the information is available from the utilities upon reasonable request.[323] As the LEC conduit owner is required to keep this data precisely as required for the formula, we will allow them to use it in the rate calculation.[324]

---

conduit, respectively.

[316]18 C.F.R. Part 101, Description of Accounts, Account 190.

[317]*See, e.g.*, Bell South Comments at 8; GTE Comments at 14; SBC Comments at 20.

[318]Bell South Comments at 8.

[319]NCTA Reply at 33–34.

[320]*Pole Attachment Order*, 2 FCC Rcd 4387 (1987).

[321]2 FCC Rcd 4387 (1987).

[322]*Pole Attachment Order*, 2 FCC Rcd 4387 (1987) at ¶ 37.

[323]*Second Report and Order*, 72 FCC 2d 59 at ¶ 32.

[324]*See* BellSouth Comments at 8. The subsidiary accounts for Accounts 4100 and 4340 are required to be maintained and reported to the Commission. *See* 47 C.F.R. §§ 43.21, 43.43, 32.4100 and 32.4340. *See also*, Biennial Regulatory Review, Review of Accounting and Cost Allocation Requirements, FCC 99-106 at ¶ 15 (*rel*. June 30, 1999) and Biennial Regulatory Review, Review of ARMIS Reporting Requirements, FCC 99-107 at ¶ 13 (*rel*. June 30, 1999).

102. To determine the net conduit investment for conduit owned by an electric utility, we base the gross conduit investment on Account 366. Edison Electric/UTC suggests that portions of Accounts 367 (Underground conductors and devices) and 369 (Services) should be included.[325] We disagree. Conductors and related devices are part of the utility's core business services' infrastructure, and such capital expenses are not included in the *Cable Formula* for poles.[326] Account 367 may include some costs of installed materials that provide support for the conduit system, but such a portion of that account is reflected in the maintenance element calculations. The electric utility has an opportunity to recover appropriate expenses reported in those accounts in the carrying charges.

103. We also reject electric utilities' suggestions that portions of Accounts 580 (Operation - Supervision and Engineering) and 583 (Operation - Overhead Line Expenses, Major Utilities Only) should be included, even if they may contain some expenses incurred with respect to the electric power distribution plant.[327] The descriptions of the expenses included in FERC Part 101 Accounts 367, 369, 580 and 583, relate directly to the electric utilities' core business operations rather than "actual capital costs attributable to the entire pole, duct, conduit or right-of-way."[328] The same appears true of FERC Accounts 357 (Underground Conduit), 358 (Underground Conductors and Devices), 371 (Installation on Customer Premises), and 373 (Street Lighting and Signal Systems) which are also not included in the formula.[329]

b. System Duct Length

104. The denominator for the Net Linear Cost of Conduit element within the formula is based on duct length. In the *Notice* we indicated that duct length could be stated as per linear meter or per linear foot.[330] In response, some electric utilities argue that they are not capable of readily computing conduit investment on per linear foot or meter basis because FERC accounts associated with underground system only track dollar values and not linear measurement.[331] The record indicates that the utilities often have the data required for the calculations and, when they do not have the data they can estimate it from the data

[325] *See, e.g.*, Edison Electric/UTC Comments at 25.

[326] *Notice* at ¶ 42.

[327] *See* Carolina Power Comments at 50-52; *see also* 18 C.F.R. Part 101: descriptions of accounts and operating expense reporting instructions.

[328] 47 U.S.C. § 224(d)(1).

[329] *See* 18 C.F.R. Part 101, Description of Accounts.

[330] *Notice* at ¶ 39 n.76.

[331] *See, e.g.*, Ohio Edison Comments at 42.

they have.[332] The net cost data is available from FERC reports and, although electric utilities are not required to report the linear footage of conduit deployed, we are informed that they routinely produce linear footage data during state conduit rate proceedings.[333] Electric utility corporate or engineering departments have records on installed plant.[334] Moreover, as NCTA observes, when a utility is unable to obtain the requisite data, information from other sources may be used.[335] A determination of the total length of duct and conduit in the system can be made with a precision comparable to that reached in determining the number of poles owned by the utility. The utility must, however, specify the method used for computing the duct length and must disclose this information to all attachers upon request.

5. Carrying Charge Rate (Conduit)

105. The elements of the carrying charge rate are: administrative, maintenance, depreciation, taxes and rate of return.[336] In the *Pole Attachment Order*,[337] the Commission identified the regulatory accounts to be used, where possible, in applying the *Cable Formula* to determine the maximum allowable rate for pole attachments on poles. The Commission addressed the pole attachment formula and accounts to be used for determining a pole attachment rate for LEC-owned conduit systems in *Multimedia Cablevision*.[338] The accounts to be used for an attachment rate for a conduit system owned by an electric utility will be accounts reported to FERC that are comparable to the LEC accounts identified in *Multimedia Cablevision*,[339] as discussed in this *Order*.[340]

106. To calculate the carrying charge rate, the Commission developed a formula that relates each of these elements to a utility's net plant investment appropriate to the location of the pole attachment (e.g., poles, conduit system, right-of-way).[341] That formula is:

---

[332] *See* Time Warner Reply at 10; *see also* NCTA Comments at 48.

[333] NCTA Reply at 48–50; *see also* MCI Reply at 39–40.

[334] *See, e.g.*, Carolina Power Comments at 66.

[335] NCTA Reply at 49.

[336] *Pole Attachment Order*, 2 FCC Rcd at 4387, 4391 (1987), ¶ 25.

[337] 2 FCC Rcd 4387, 4402-03, Attachment B (1987); *see also American Cablesystems of Florida, Ltd.*, 10 FCC Rcd 10934 (1995).

[338] 11 FCC Rcd 11202 (*rel.* Sep. 3, 1996).

[339] 11 FCC Rcd 11202 (1996).

[340] *See* Appendix C-3 for LECs and Appendix C-4 for electric utilities.

[341] *Pole Attachment Order*, 2 FCC Rcd at 4387, 4402-03, Attachment B (1987).

$$\text{Carrying Charge Rate} = \text{Administrative} + \text{Maintenance} + \text{Depreciation} + \text{Taxes} + \text{Rate of Return}$$

107. The administrative, taxes, and rate of return elements will be the same for use in a formula for pole attachments in conduits and rights-of-way as on poles. We have already discussed those elements, and the appropriate accounts and methodologies to develop the figures to be used in the full formula in previous sections and will not repeat our discussion here. The maintenance and depreciation elements, with the accounts and methodologies specific to conduits, are discussed in this *Order*. The *Cable Formula* for application to attachments in conduits owned by LEC and electric utilities, with all components, elements and accounts used, are attached to this *Order* as Appendix C-3 and C-4, respectively.

a. Maintenance Element

108. In the *Pole Attachment Order*, the Commission adopted procedures to identify and calculate the maintenance expenses for use in the carrying charge rate as a ratio of expenses included in the utility's maintenance account, to net investment.[342] For purposes of the calculation of the maintenance element, the denominator is the net investment which equals the sum of gross investment, minus accumulated depreciation related to conduit systems, minus accumulated deferred income taxes related to conduit systems.[343]

i. LEC owned Conduit

109. In the *Notice*, we proposed the following methodology for the maintenance element of the carrying charge rates of the *Cable Formula* for LEC conduit owners:[344]

$$\text{Maintenance Element} = \frac{\text{Account 6441}}{\underset{\text{[Net Conduit Investment]}}{\text{Account 2441} - \text{Accumulated Depreciation, conduit} - \text{Accumulated Deferred Income Taxes}}}$$

110. We affirm the use of our proposed formula to determine the maintenance carrying charge rate element for LEC owned underground conduit systems.[345] Account 2441, which unlike Account 2411 (used as the gross pole investment to determine the net cost of a bare pole) includes no non-cable related investment that supports LEC operations exclusively and, consequently, does not require the application of an adjustment factor.[346] Telecommunications carriers and LEC commenters support our conclusion that

[342] 2 FCC Rcd 4387 (1987).

[343] *Multimedia Cablevision*, 11 FCC Rcd 11202 (1996).

[344] *Notice*, 12 FCC Rcd 7449, at Appendix C.

[345] MCI Comments at 23.

manhole costs included in Account 2441 are suitable for recovery as underground conduit system costs.[347]

ii. Electric Utility Owned Conduit

111. The formula and accounts to be used for the maintenance element of the carrying charge rate of the *Cable Formula* for electric utility conduit owners is determined by applying FERC accounts analogous to those LEC accounts used in *Multimedia Cablevision*, as follow:

$$\begin{array}{c}\text{Maintenance}\\ \text{Element}\end{array} = \frac{\text{Account 594 (Maintenance of Underground Lines)}}{\begin{bmatrix}\text{Investment in}\\ \\ \text{Accounts 366, 367, \& 369}\end{bmatrix} - \begin{bmatrix}\text{Depreciation}\\ \text{Related to}\\ \text{Accounts 366, 367, \& 369}\end{bmatrix} - \begin{bmatrix}\text{Deferred Income Taxes}\\ \text{Related to}\\ \text{Accounts 366, 367, \& 369}\end{bmatrix}}$$

112. FERC Account 366 contains capital costs for installed underground conduit and tunnels used for housing distribution cables or wires.[348] For electric utilities, Accounts 367 (Underground Conductors and Devices) and 369 (Services), and corresponding maintenance expenses are included in Account 594 (Maintenance of underground lines).[349] Some electric utilities suggest inclusion of Accounts 580 (Operation and Supervision), 584 (Operation of Underground Lines), 588 (Miscellaneous Distribution Operation Expenses), 590 (Maintenance Supervision and Engineering-Major Only), and 598 (Maintenance of Miscellaneous Distribution Plant).[350] Accounts 580, 584, 588 are operational accounts which report expenses relating to the utility's core business services and not pole attachments.[351] We have addressed inclusion of Account 590 above and do not include that account in the *Cable Formula* for poles.[352] Account 598 is a miscellaneous account related generally to maintenance of equipment on customer premises and is not associated with pole attachments in conduit.[353] We will not include any portion of Accounts 580, 584, 588, 590 or 598 in the denominator of the maintenance element because the costs or expenses reported to these accounts do not reflect "operating expenses and actual capital costs of the utility

[346] *Notice* at ¶ 42.

[347] *See, e.g.*, GTE Comments at 17 n.24; Sprint Comments at 10.

[348] 18 C.F.R. Part 101, Description of Accounts.

[349] *Id.*

[350] *See* Edison Electric/UTC Comments at 26; Carolina Power Comments at 68–75; Ohio Edison Comments at 42–45.

[351] 18 C.F.R. Part 101, Description of Accounts.

[352] *See* discussion at ¶¶ 61-65 of this *Order*.

[353] 18 C.F.R. Part 101, Description of Accounts.

attributable to the . . . conduit."[354]

b. Depreciation Element

113. In the *Notice*,[355] we proposed a formula to determine the depreciation element for conduit as follows:

$$\begin{array}{c}\text{Depreciation}\\\text{Carrying Charge}\\\text{Factor}\end{array} = \begin{array}{c}\text{Depreciation}\\\text{Rate}\\\text{for Conduit}\end{array} \times \frac{\begin{array}{c}\text{Gross Conduit Investment}\\\text{(Part 32 Account 2441 / FERC Accounts 366, 367, 369)}\end{array}}{\text{Net Conduit Investment}}$$

114. Consistent with our discussions and conclusions above, we are excluding FERC Accounts 367 and 369 from the numerator for this equation for electric utility conduit owners.[356] Therefore, only FERC Account 366 will be used as a basis for Gross Conduit Investment under the formula for electric utilities. For LECs, ARMIS Account 2441 represents the corresponding Gross Conduit Investment account under the formula. We adopt our proposed formula, as modified, as follows:

$$\begin{array}{c}\text{Depreciation}\\\text{Element}\end{array} = \frac{\begin{array}{c}\text{Gross Conduit Investment}\\\text{(ARMIS Account 2441 / FERC Accounts 366)}\end{array}}{\text{Net Conduit Investment}} \times \begin{array}{c}\text{Depreciation}\\\text{Rate}\\\text{for Conduit}\end{array}$$

VII. FINAL REGULATORY FLEXIBILITY ACT ANALYSIS

115. As required by the Regulatory Flexibility Act ("RFA"),[357] an Initial Regulatory Flexibility Analysis ("IRFA") was incorporated in the *Notice*.[358] The Commission sought written public comment on the proposals in the *Notice* including comment on the IRFA. The comments received are discussed below. This present Final Regulatory Flexibility Analysis ("FRFA") conforms to the RFA.[359]

1. Need for, and Objectives of, the *Order*

[354] 47 U.S.C. § 224(d)(1).

[355] 12 FCC Rcd 7449 at Appendix C.

[356] *See* discussion regarding FERC Account 367 and 369 at ¶¶ 119-121 of this *Order*.

[357] *See* 5 U.S.C. § 603. The RFA, *see* 5 U.S.C. § 601 *et. seq.*, has been amended by the Contract With America Advancement Act of 1996, Pub. L. No. 104-121, 110 Stat. 847 (1996) ("CWAAA"). Title II of the CWAAA is the Small Business Regulatory Enforcement Fairness Act of 1996 ("SBREFA").

[358] *Notice of Proposed Rulemaking*, CS Docket No. 97-98, 12 FCC Rcd 7449, ¶¶ 49-79 (1997).

[359] *See* 5 U.S.C. § 604.

116. In 1987, the Commission adopted its current pole attachment formula for calculating the maximum just and reasonable rates utilities may charge cable systems for pole attachments. Since then the Commission replaced its accounting system for telephone companies, creating Part 32. This created a need to advise telephone companies about how the new system should be used in the pole attachment formula. The Telecommunications Act of 1996 made pole attachment rules applicable to telecommunications providers. The existing pole attachment formula applies to them until February 8, 2001. This gave rise to a need to ensure that the pole attachments rules would appropriately accommodate these new attachers. The use of conduit by cable systems and had not yet been addressed in detail by the Commission. This needs to be done in light of the anticipated number of new attachers whose entry into the marketplace the Commission wishes to facilitate. We recognize that a significant number of new attachers might be small businesses.

117. The objectives of the rules adopted herein are consistent with Congressional intent to provide a clear methodology to determine just and reasonable pole attachment rates in a manner that uses publicly available and verifiable data whenever possible. The objectives of the rules adopted herein change the formula methodology used to determine a just and reasonable pole attachment rate to reflect the present Part 32 accounting system for telephone companies that replaced the former Part 31 rules in 1988. Finally, the objectives of the rules adopted herein are to identify a conduit methodology that will determine the maximum just and reasonable rates utilities may charge cable operators and telecommunications carriers for pole attachments to conduit systems. Although our rules do not differentiate between large and small businesses, our use of presumptions and publicly available data in our methodology ensures that small businesses will not be discouraged from seeking recourse with the Commission against the imposition of unreasonable pole attachment rates.

2. Summary of Significant Issues Raised by Public Comments In Response to the IRFA

118. Small Cable Business Association ("SCBA") filed comments in response to the IRFA contained in the *Notice*, and, to the extent they are relevant to the issues in this proceeding, we incorporate them herein by reference.[360] SCBA claims in its IRFA comments that, because of the statutory exclusion of cooperatives from the definition of utility, Section 224 does not minimize market entry barriers for small cable operators.[361] According to SCBA, the IRFA in the *Notice* fails to consider this issue.[362] SCBA claims that small cable systems will be particularly hurt by the statutory exemption of cooperatives from

[360] *Cf.* discussion *infra* at ¶ 174. Section 224 only applies to utilities not excluded by the statute. Market entry barriers for small operators, seeking pole attachments to utility infrastructure over which Section 224 jurisdiction applies, will be minimized as we outline in ¶ 174.

[361] SCBA IRFA Comments at 2.

[362] *Id.*

the definition of utility because small cable systems often operate in rural areas and therefore necessarily attach their plant to rural telephone and electric cooperatives.[363] In its Reply to the SCBA's comments, the National Telephone Cooperative Association responded that " . . . the exemption [of cooperatives from Section] 224 does not deprive SCBA members of available legal remedies in connection with pole attachment agreements negotiated with exempt electric or telephone cooperatives."[364] We note that the SCBA does not appear to be claiming that our rules will disproportionately burden small cable systems, but that where our rules do not apply, small cable system operators will be disproportionately harmed. Because the exemption for cooperatives was set forth by Congress clearly in Section 224(a)(1), the Commission is left no discretion to address SCBA's concerns in this regard. In general comments, the National Cable Television Association ("NCTA") acknowledged that:

> The benefits [of the Commission's current pole attachment regulatory regime] are most vivid in the case of small cable operators. Small operators are peculiarly vulnerable to pole rent overcharges, because of the nature of their service areas. The Commission has recognized that small systems serve areas that are far less densely populated areas than the areas served by large operators. A small rural operator might serve half of the homes along a road with only 20 homes per mile, but might need 30 poles to reach those 10 subscribers. A pole rent increase creates an enormous push on [cable] rates, and frequently makes rural line extensions uneconomical. These same small operators are often the very parties without the budgets to litigate expensive document-intensive rate cases.[365]

The NCTA's comments recognize that the Commission's chosen methodology does not excessively burden small businesses.

3. Description and Estimate of the Number of Small Entities To Which Rules Will Apply

119. The RFA generally defines a "small entity" as having the same meaning as the terms "small business," "small organization," and "small governmental jurisdiction."[366] In addition, the term

[363] SCBA IRFA at 2.

[364] National Telephone Cooperative Association Reply at 2-3. A national association of approximately 500 local exchange carriers that provide service primarily in rural areas, the National Telephone Cooperative Association reports that its members are small local exchange carriers that are "rural telephone companies" as defined in the Telecommunications Act of 1996, and about half of its members are organized as cooperatives. *Id*. at 1.

[365] NCTA Comments at 5-6.

[366] 5 U.S.C. § 601(6).

"small business" has the same meaning as the term small business concern under the Small Business Act.[367] A "small business concern" is one that: (1) is independently owned and operated; (2) is not dominant in its field of operation; and (3) satisfies any additional criteria established by the Small Business Administration ("SBA").[368] For many of the entities described below, the SBA has defined small business categories through Standard Industrial Classification ("SIC") codes.

a. Utilities

120. Many of the decisions and rules adopted herein may have a significant effect on a substantial number of utility companies. Section 224 defines a "utility" as "any person who is a local exchange carrier or an electric, gas, water, steam, or other public utility, and who owns or controls poles, ducts, conduits, or rights-of-way used, in whole or in part, for any wire communications. Such term does not include any railroad, any person who is cooperatively organized, or any person owned by the Federal Government or any State." The SBA has provided the Commission with a list of utility firms which may be effected by this rulemaking. Based upon the SBA's list, the Commission concludes that all of the following types of utility firms may be affected by the Commission's implementation of Section 224.

(1) Electric Utilities (SIC 4911, 4931 & 4939)

121. *Electric Services (SIC 4911).* The SBA has developed a definition for small electric utility firms.[369] The Census Bureau reports that a total of 1379 electric utilities were in operation for at least one year at the end of 1992. According to SBA, a small electric utility is an entity whose gross revenues did not exceed five million dollars in 1992.[370] The Census Bureau reports that 447 of the 1379 firms listed had total revenues below five million dollars.[371]

122. *Electric and Other Services Combined (SIC 4931).* The SBA has classified this entity as

---

[367]5 U.S.C. § 601(3) (incorporating by reference the definitions of "small business concern" in 15 U.S.C. § 632). Pursuant to 5 U.S.C. § 601(3), the statutory definition of a small business applies "unless an agency, after consultation with the Office of Advocacy of the Small Business Administration and after opportunity for public comment, establishes one or more 'definitions' of such term which are appropriate to the activities of the agency and publishes such definitions in the Federal Register."

[368]Small Business Act, 15 U.S.C. § 632.

[369]Executive Office of the President, Office of Management and Budget, Standard Industrial Classification Manual (1987).

[370]13 C.F.R. § 121.201.

[371]U.S. Department of Commerce, Bureau of the Census, 1992 Economic Census Industry and Enterprise Receipts Size Report, Table 2D (Bureau of Census data under contract to the Office of Advocacy of the SBA).

a utility whose business is less than 95% electric in combination with some other type of service.[372] The Census Bureau reports that a total of 135 such firms were in operation for at least one year at the end of 1992. The SBA's definition of a small electric and other services combined utility is a firm whose gross revenues did not exceed five million dollars in 1992.[373] The Census Bureau reported that 45 of the 135 firms listed had total revenues below five million dollars.[374]

123. *Combination Utilities, Not Elsewhere Classified (SIC 4939)*. The SBA defines this utility as providing a combination of electric, gas, and other services which are not otherwise classified.[375] The Census Bureau reports that a total of 79 such utilities were in operation for at least one year at the end of 1992. According to SBA's definition, a small combination utility is a firm whose gross revenues did not exceed five million dollars in 1992.[376] The Census Bureau reported that 63 of the 79 firms listed had total revenues below five million dollars.[377]

(2) Gas Production and Distribution
(SIC 4922, 4923, 4924, 4925 & 4932)

124. *Natural Gas Transmission (SIC 4922).* The SBA's definition of a natural gas transmitter is an entity that is engaged in the transmission and storage of natural gas.[378] The Census Bureau reports that a total of 144 such firms were in operation for at least one year at the end of 1992. According to SBA's definition, a small natural gas transmitter is an entity whose gross revenues did not exceed five million dollars in 1992.[379] The Census Bureau reported that 70 of the 144 firms listed had total revenues below five million dollars.[380]

125. *Natural Gas Transmission and Distribution (SIC 4923).* The SBA has classified this

---

[372] *See supra* note 369.

[373] 13 C.F.R. § 121.201.

[374] *See supra* note 371.

[375] *See supra* note 369.

[376] 13 C.F.R. § 121.201.

[377] *See supra* note 371.

[378] *See supra* note 369.

[379] 13 C.F.R. § 121.201.

[380] *See supra* note 371.

entity as a utility that transmits and distributes natural gas for sale.[381] The Census Bureau reports that a total of 126 such entities were in operation for at least one year at the end of 1992. The SBA's definition of a small natural gas transmitter and distributor is a firm whose gross revenues did not exceed five million dollars.[382] The Census Bureau reported that 43 of the 126 firms listed had total revenues below five million dollars.[383]

126. *Natural Gas Distribution (SIC 4924)*. The SBA defines a natural gas distributor as an entity that distributes natural gas for sale.[384] The Census Bureau reports that a total of 478 such firms were in operation for at least one year at the end of 1992. According to the SBA, a small natural gas distributor is an entity whose gross revenues did not exceed five million dollars in 1992.[385] The Census Bureau reported that 267 of the 478 firms listed had total revenues below five million dollars.[386]

127. *Mixed, Manufactured, or Liquefied Petroleum Gas Production and/or Distribution (SIC 4925)*. The SBA has classified this entity as a utility that engages in the manufacturing and/or distribution of the sale of gas. These mixtures may include natural gas.[387] The Census Bureau reports that a total of 43 such firms were in operation for at least one year at the end of 1992. The SBA's definition of a small mixed, manufactured or liquefied petroleum gas producer or distributor is a firm whose gross revenues did not exceed five million dollars in 1992.[388] The Census Bureau reported that 31 of the 43 firms listed had total revenues below five million dollars.[389]

128. *Gas and Other Services Combined (SIC 4932)*. The SBA has classified this entity as a gas company whose business is less than 95% gas, in combination with other services.[390] The Census Bureau reports that a total of 43 such firms were in operation for at least one year at the end of 1992.

[381] *See supra* note 369.

[382] 13 C.F.R. § 121.201.

[383] *See supra* note 371.

[384] *See supra* note 369.

[385] 13 C.F.R. § 121.201.

[386] *See supra* note 371.

[387] *See supra* note 369.

[388] 13 C.F.R. § 121.201.

[389] *See supra* note 371.

[390] *See supra* note 369.

According to the SBA, a small gas and other services combined utility is a firm whose gross revenues did not exceed five million dollars in 1992.[391] The Census Bureau reported that 24 of the 43 firms listed had total revenues below five million dollars.[392]

(3) Water Supply (SIC 4941)

129. The SBA defines a water utility as a firm who distributes and sells water for domestic, commercial and industrial use.[393] The Census Bureau reports that a total of 3,169 water utilities were in operation for at least one year at the end of 1992. According to SBA's definition, a small water utility is a firm whose gross revenues did not exceed five million dollars in 1992.[394] The Census Bureau reported that 3065 of the 3169 firms listed had total revenues below five million dollars.[395]

(4) Sanitary Systems (SIC 4952, 4953 & 4959)

130. *Sewerage Systems (SIC 4952)*. The SBA defines a sewage firm as a utility whose business is the collection and disposal of waste using sewage systems.[396] The Census Bureau reports that a total of 410 such firms were in operation for at least one year at the end of 1992. According to SBA's definition, a small sewerage system is a firm whose gross revenues did not exceed five million dollars.[397] The Census Bureau reported that 369 of the 410 firms listed had total revenues below five million dollars.[398]

131. *Refuse Systems (SIC 4953)*. The SBA defines a firm in the business of refuse as an establishment whose business is the collection and disposal of refuse "by processing or destruction or in the operation of incinerators, waste treatment plants, landfills, or other sites for disposal of such materials."[399] The Census Bureau reports that a total of 2287 such firms were in operation for at least one year at the end

[391] 13 C.F.R. § 121.201.

[392] *See supra* note 371.

[393] *See supra* note 369.

[394] 13 C.F.R. § 121.201.

[395] *See supra* note 371.

[396] *See supra* note 369.

[397] 13 C.F.R. § 121.201.

[398] *See supra* note 371.

[399] *See supra* note 369.

of 1992. According to SBA's definition, a small refuse system is a firm whose gross revenues did not exceed six million dollars.[400] The Census Bureau reported that 1908 of the 2287 firms listed had total revenues below six million dollars.[401]

132. *Sanitary Services, Not Elsewhere Classified (SIC 4959)*. The SBA defines these firms as engaged in sanitary services.[402] The Census Bureau reports that a total of 1214 such firms were in operation for at least one year at the end of 1992. According to SBA's definition, a small sanitary service firms gross revenues did not exceed five million dollars.[403] The Census Bureau reported that 1173 of the 1214 firms listed had total revenues below five million dollars.[404]

(5) Steam and Air Conditioning Supply (SIC 4961)

133. The SBA defines a steam and air conditioning supply utility as a firm who produces and/or sells steam and heated or cooled air.[405] The Census Bureau reports that a total of 55 such firms were in operation for at least one year at the end of 1992. According to SBA's definition, a steam and air conditioning supply utility is a firm whose gross revenues did not exceed nine million dollars.[406] The Census Bureau reported that 30 of the 55 firms listed had total revenues below nine million dollars.[407]

(6) Irrigation Systems (SIC 4971)

134. The SBA defines irrigation systems as firms who operate water supply systems for the purpose of irrigation.[408] The Census Bureau reports that a total of 297 firms were in operation for at least one year at the end of 1992. According to SBA's definition, a small irrigation service is a firm whose gross revenues did not exceed five million dollars.[409] The Census Bureau reported that 286 of the 297 firms

---

[400] 13 C.F.R. § 121.201.

[401] *See supra* note 371.

[402] *See supra* note 369.

[403] 13 C.F.R. § 121.201.

[404] *See supra* note 371.

[405] *See supra* note 369.

[406] 13 C.F.R. § 121.201.

[407] *See supra* note 371.

[408] *See supra* note 369.

[409] 13 C.F.R. § 121.201.

listed had total revenues below five million dollars.[410]

b. Telephone Companies (SIC 4813)

135. Many of the decisions and rules adopted herein may have a significant effect on a substantial number of small telephone companies. The SBA has defined a small business for SIC code 4813 (Telephone Communications, except Radiotelephone) to be a small entity when it has no more than 1500 employees.[411] The Census Bureau reports that, at the end of 1992, there were 3497 firms engaged in providing telephone services, as defined therein, for at least one year.[412] This number contains a variety of different categories of carriers, including local exchange carriers ("LECs"), interexchange carriers ("IXCs"), competitive access providers ("CAPs"), cellular carriers, mobile service carriers, operator service providers, pay telephone operators, personal communications service ("PCS") providers, covered SMR providers and resellers. Some of those 3497 telephone service firms may not qualify as small entities or small incumbent LECs because they are not "independently owned and operated."[413] We therefore conclude that fewer than 3497 telephone service firms are small entity telephone service firms or small incumbent LECs that may be affected by this *Order*. Below, we estimate the potential number of small entity telephone service firms or small incumbent LEC's that may be affected by the rules adopted herein in this service category.

(1) Wireline Carriers and Service Providers

136. The SBA has developed a definition of small entities for telephone communications companies other than radiotelephone (wireless) companies. The Census Bureau reports that, there were 2321 such telephone companies in operation for at least one year at the end of 1992.[414] According to SBA's definition, a small business telephone company other than a radiotelephone company is one employing no more than 1500 persons.[415] Of the 2321 non-radiotelephone companies listed by the Census Bureau, 2295 were reported to have fewer than 1000 employees. Thus, at least 2295 non-radiotelephone companies that might qualify as small entities or small incumbent LECs, or small entities based on these employment statistics. Although some of these carriers are likely not independently owned and operated,

[410] *See supra* note 371.

[411] 13 C.F.R. § 121.201.

[412] United States Department of Commerce, Bureau of the Census, *1992 Census of Transportation, Communications, and Utilities: Establishment and Firm Size*, at Firm Size 1-123 (1995) ("*1992 Census*").

[413] 15 U.S.C. § 632(a)(1).

[414] *1992 Census, supra* at Firm size 1-123.

[415] 13 C.F.R. § 121.201.

we are unable at this time to estimate with greater precision the number of wireline carriers and service providers that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 2295 small entity telephone communications companies other than radiotelephone companies that may be affected by the decisions or rules adopted in this *Order*.

(2) Local Exchange Carriers

137. Neither the Commission nor SBA has developed a definition of small providers of local exchange services. The closest applicable definition under SBA rules is for telephone communications companies other than radiotelephone (wireless) companies (SIC 4813).[416] The most reliable source of information regarding the number of LECs nationwide appears to be the data that the Commission publishes annually in its *Telecommunications Industry Revenue* report, regarding the Telecommunications Relay Service ("TRS"). According to "*TRS Worksheet*" data released in November 1997, there are 1371 companies reporting that they categorize themselves as LECs.[417] Although some of these carriers are likely not independently owned and operated, or have more than 1500 employees, we are unable at this time to estimate with greater precision the number of LECs that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 1371 small incumbent LECs that may be affected by the rules adopted herein.

(3) Interexchange Carriers

138. Neither the Commission nor SBA has developed a definition of small entities specifically applicable to providers of interexchange services. The closest applicable definition under SBA rules is for telephone communications companies other than radiotelephone (wireless) companies (SIC 4813). The most reliable source of information regarding the number of IXCs nationwide of which we are aware appears to be the data that we collect annually in connection with TRS. According to our most recent data, 143 companies reported that they were engaged in the provision of interexchange services.[418] Although some of these carriers are likely not independently owned and operated, or have more than 1500 employees, we are unable at this time to estimate with greater precision the number of IXCs that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 143 small entity IXCs that may be affected by the decisions and rules adopted in this *Order*.

(4) Competitive Access Providers

139. Neither the Commission nor SBA has developed a definition of small entities specifically

[416] *Id.*

[417] Federal Communications Commission, Telecommunications Industry Revenue: TRS Fund Worksheet Data, Figure 2 (Number of Carriers Paying Into the TRS Fund by Type of Carrier) (Nov. 1997) ("*TRS Worksheet*" data).

[418] TRS Worksheet.

applicable to providers of competitive access services. The closest applicable definition under SBA rules is for telephone communications companies other than radiotelephone (wireless) companies (SIC 4813). The most reliable source of information regarding the number of CAPs nationwide of which we are aware appears to be the data that we collect annually in connection with the *TRS Worksheet*. According to our most recent data, 109 companies reported that they were engaged in the provision of competitive access services.[419] Although some of these carriers are likely not independently owned and operated, or have more than 1500 employees, we are unable at this time to estimate with greater precision the number of CAPs that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 109 small entity CAPs that may be affected by the decisions and rules adopted herein.

(5) Cellular Service Carriers

140. Neither the Commission nor SBA has developed a definition of small entities specifically applicable to providers of cellular services. The closest applicable definition under SBA rules is for telephone communications companies other than radiotelephone (wireless) companies (SIC 4812). The most reliable source of information regarding the number of cellular service carriers nationwide of which we are aware appears to be the data that we collect annually in connection with the *TRS Worksheet.* The *TRS Worksheet* places cellular licensees and Personal Communications Service ("PCS") licensees in one group. According to the most recent data, there are 804 carriers reporting that they categorize themselves as either PCS or cellular carriers.[420] Although it seems certain that some of these carriers are not independently owned and operated, or have more than 1500 employees, we are unable at this time to estimate with greater precision the number of cellular service carriers that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 804 small entity cellular service carriers that may be affected by the decisions and rules adopted in this *Order*.

(6) Mobile Service Carriers

141. Neither the Commission nor SBA has developed a definition of small entities specifically applicable to mobile service carriers, such as paging companies. The closest applicable definition under SBA rules is for telephone communications companies other than radiotelephone (wireless) companies (SIC 4813). The most reliable source of information regarding the number of mobile service carriers nationwide of which we are aware appears to be the data that we collect annually in connection with the *TRS Worksheet*. According to our most recent data, 172 companies reported that they were engaged in the provision of mobile services.[421] Although it seems certain that some of these carriers are not independently owned and operated, or have more than 1500 employees, we are unable at this time to estimate with greater precision the number of mobile service carriers that would qualify under SBA's definition. Consequently,

[419] *Id.* This *TRS Worksheet* category also includes Competitive Local Exchange Carriers ("CLECs").

[420] *Id.*

[421] *Id.*

we estimate that there are fewer than 172 small entity mobile service carriers that may be affected by the decisions and rules adopted in this *Order*.

(7) Broadband Personal Communications Services ("PCS") Licensees

142. The broadband PCS spectrum is divided into six frequency blocks designated A through F, and the Commission has held auctions for each block. The Commission has defined "small entity" for Blocks C and F as an entity that has average gross revenues of less than $40 million in the three previous calendar years. For Block F, an additional classification for "very small business" was added and is defined as an entity that, together with their affiliates, has average gross revenues of not more than $15 million for the preceding three calendar years.[422] These regulations defining "small entity" in the context of broadband PCS auctions has been approved by the SBA.[423] No small businesses within the SBA-approved definition bid successfully for licenses in Blocks A and B. There were 90 winning bidders that qualified as small entities in the Block C auction. A total of 93 small and very small business bidders won approximately 40% of the 1479 licenses for Blocks D, E, and F.[424] However, licenses for blocks C through F have not been awarded fully, therefore there are few, if any, small businesses currently providing PCS services. Based on this information, we conclude that the number of broadband PCS licensees will include the 90 winning C Block bidders and the 93 qualifying bidders in the D, E, and F blocks, for a total of 183 small PCS providers as defined by the SBA and the Commission's auction rules. We note that the *TRS Worksheet* data track PCS licensees in the reporting category "Cellular or Personal Communications Service Carrier." As noted *supra* in the paragraph regarding cellular carriers, according to the most recent data, there are 804 carriers reporting that they place themselves in this category.

(8) Specialized Mobile Radio ("SMR") Licensees

143. Pursuant to 47 C.F.R. §§ 90.814(b)(1) and 90.912(b)(1), the Commission has defined small entity in auctions for geographic area 800 MHz and 900 MHz SMR licenses as a firm that had average annual gross revenues of less than $15 million in the three previous calendar years. This definition of a small entity in the context of 800 MHz and 900 MHz SMR has been approved by the SBA.[425] The

[422] *See Report and Order* (Amendment of Parts 20 and 24 of the Commission's Rules -- Broadband PCS Competitive Bidding and the Commercial Mobile Radio Service Spectrum Cap), WT Docket No. 96-59, FCC 96-278 (1996) at ¶ 60, 61 FR 33859 (July 1, 1996).

[423] *See Fifth Report and Order* (Implementation of Section 309(j) of the Communications Act -- Competitive Bidding), PP Docket No. 93-253, 9 FCC Rcd 5532, 5581-84 (1994).

[424] FCC News, *Broadband PCS, D, E and F Block Auction Closes*, No. 71744 (*rel*. January 14, 1997).

[425] *See Second Order on Reconsideration and Seventh Report and Order* (Amendment of Parts 2 and 90 of the Commission's Rules to Provide for the Use of 200 Channels Outside the Designated Filing Areas in the 896-901 MHz and the 935-940 MHz Bands Allotted to the Specialized Mobile Radio Pool), PR Docket No. 89-583, 11 FCC

rules adopted in this *Order* may apply to SMR providers in the 800 MHz and 900 MHz bands that either hold geographic area licenses or have obtained extended implementation authorizations. We do not know how many firms provide 800 MHz or 900 MHz geographic area SMR service pursuant to extended implementation authorizations, nor how many of these providers have annual revenues of less than $15 million. We assume, for purposes of this FRFA, that all of the extended implementation authorizations may be held by small entities which may be affected by the decisions and rules adopted in this *Order*. We note that the *TRS Worksheet* data track SMR licensees in the reporting category "Paging and Other Mobile Carriers." According to the most recent data, there are 172 carriers, including SMR carriers, reporting that they place themselves in this category.

144. In April 1997, the Commission held auctions for geographic area licenses in the 900 MHz SMR band. There were 60 winning bidders that qualified as small entities in the 900 MHz auction. Based on this information, we conclude that the number of 900 MHz geographic area SMR licensees affected by the rules adopted in this *Order* includes these 60 small entities. In December 1997, the Commission also held auctions for the 525 licenses for the upper 200 channels in the 800 MHz SMR band. There were 10 winning bidders that qualified as small entities in that auction. Based on this information, we conclude that the number of geographic area SMR licensees that may be affected by the rules adopted in this *Order* also includes these 10 small entities. However, the Commission has not yet determined how many licenses will be awarded for the lower 230 channels in the 800 MHz geographic area SMR auction. There is no basis, moreover, on which to estimate how many small entities will win these licenses. Given that nearly all radiotelephone companies have fewer than 1000 employees and that no reliable estimate of the number of prospective 800 MHz licensees for the lower 230 channels can be made, we conclude, for purposes of this FRFA, that some or all of the licenses could conceivably be awarded to small entities that may be affected by the decisions and rules adopted in this *Order*.

(9) Resellers

145. Neither the Commission nor SBA has developed a definition of small entities specifically applicable to resellers. The closest applicable definition under SBA rules is for all telephone communications companies (SIC 4812 and 4813). The most reliable source of information regarding the number of resellers nationwide of which we are aware appears to be the data that we collect annually in connection with the *TRS Worksheet*. According to our most recent data, 339 companies reported that they were engaged in the resale of telephone services.[426] Although it seems certain that some of these carriers are not independently owned and operated, or have more than 1500 employees, we are unable at this time to estimate with greater precision the number of resellers that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 339 small entity resellers that may be affected by the decisions and rules adopted in this *Order*.

Rcd 2639, 2693-702 (1995); *First Report and Order, Eighth Report and Order, and Second Further Notice of Proposed Rulemaking* (Amendment of Part 90 of the Commission's Rules to Facilitate Future Development of SMR Systems in the 800 MHz Frequency Band), PR Docket No. 93-144, 11 FCC Rcd 1463 (1995).

[426] TRS Worksheet.

c. Wireless (Radiotelephone) Carriers (SIC 4812)

146. Pursuant to the terms of the 1996 Act, wireless carriers are entitled to affix their equipment to utility poles with rates consistent with the Commission's rules discussed herein. SBA has developed a definition of small entities for radiotelephone (wireless) companies. The Census Bureau reports that there were 1176 such companies in operation for at least one year at the end of 1992.[427] According to SBA's definition, a small business radiotelephone company is one employing no more than 1500 persons.[428] The Census Bureau also reported that 1164 of those radiotelephone companies had fewer than 1000 employees. Thus, even if all of the remaining 12 companies had more than 1500 employees, there would still be 1164 radiotelephone companies that might qualify as small entities if they are independently owned and operated. Although some of these carriers are likely not independently owned and operated, we are unable at this time to estimate with greater precision the number of radiotelephone carriers and service providers that would qualify as small business concerns under SBA's definition. Consequently, we estimate that there are fewer than 1164 small entity radiotelephone companies that may be affected by the rules adopted herein.

d. Cable System Operators (SIC 4841)

147. The SBA has developed a definition of small entities for cable and other pay television services, which includes all such companies generating less than $11 million in revenue annually.[429] This definition includes cable systems operators, closed circuit television services, direct broadcast satellite services, multipoint distribution systems, satellite master antenna systems and subscription television services. According to the Census Bureau, there were 1423 such cable and other pay television services generating less than $11 million in revenue.[430]

148. The Commission has developed its own definition of a small cable system operator for the purposes of rate regulation. Under the Commission's rules, a "small cable company," is one serving fewer than 400,000 subscribers nationwide.[431] Based on our most recent information, we estimate that there were

[427] *See* 1992 Census.

[428] 13 C.F.R. § 121.201.

[429] 13 C.F.R. § 121.201.

[430] *See supra* note 369.

[431] 47 C.F.R. § 76.901(e). The Commission developed this definition based on its determinations that a small cable system operator is one with annual revenues of $100 million or less. *Sixth Report and Order and Eleventh Order on Reconsideration* (Implementation of Sections of the 1992 Cable Act: Rate Regulation), 10 FCC Rcd 7393.

1439 cable systems that qualified as small cable system operators at the end of 1995.[432] Since then, some of those companies may have grown to serve over 400,000 subscribers, and others may have been involved in transactions that caused them to be combined with other cable systems. Consequently, we estimate that there are fewer than 1439 small entity cable system operators that may be affected by the decisions and rules adopted in this *Order*.

149. The Communications Act also contains a definition of a small cable system operator, which is "a cable operator that, directly or through an affiliate, serves in the aggregate fewer than one percent of all subscribers in the United States and is not affiliated with any entity or entities whose gross annual revenues in the aggregate exceed $250,000,000."[433] The Commission found that an operator serving fewer than 617,000 subscribers shall be deemed a small operator, if its annual revenues, when combined with the total annual revenues of all of its affiliates, do not exceed $250 million in the aggregate.[434] Based on available data, we find that the number of cable systems serving 617,000 subscribers or less totals 1450. Although it seems certain that some of these cable system operators are affiliated with entities whose gross annual revenues exceed $250,000,000, we are unable at this time to estimate with greater precision the number of cable system operators that would qualify as small cable systems under the definition in the Communications Act.

e. Municipalities

150. The term "small governmental jurisdiction" is defined as "governments of . . . districts, with a population of less than 50,000."[435] There are 85,006 governmental entities in the United States.[436] This number includes such entities as states, counties, cities, utility districts and school districts. We note that Section 224 specifically excludes any utility which is cooperatively organized, or any person owned by the Federal Government or any State. For this reason, we believe that Section 224 will have minimal if any affect upon small municipalities. Further, there are 18 states and the District of Columbia that regulate pole attachments pursuant to Section 224(c)(1). Of the 85,006 governmental entities, 38,978 are counties, cities and towns. The remainder are primarily utility districts, school districts, and states. Of the 38,978 counties, cities and towns, 37,566 or 96%, have populations of fewer than 50,000.

D. Description of Projected Reporting, Recordkeeping, and Other Compliance Requirements

[432] Paul Kagan Associates, Inc., *Cable TV Investor*, Feb. 29, 1996 (based on figures for Dec. 30, 1995).

[433] 47 U.S.C. § 543(m)(2).

[434] 47 C.F.R. § 76.1403(b).

[435] 5 U.S.C. § 601(5).

[436] United States Dept. of Commerce, Bureau of the Census, *1992 Census of Governments*.

151. The rules adopted in this *Order* may require a change in certain recordkeeping requirements for conduit systems. A utility will now have to maintain specific records relating to the number of linear meters, or feet, of conduit for the purpose of determining the net cost of conduit and the amount of conduit linear measurement in which a pole attachment exists. Although this requirement affects both large and small businesses equally, we believe that through the use of presumptions, specific accounts and publicly available data in our methodology, we have avoided a more extensive regulatory scheme which might have burdened small entities. We conclude that our rules will not disproportionately burden small entities.

E. Steps Taken to Minimize Significant Economic Impact on Small Entities, and Significant Alternatives Considered

152. Section 703 of the 1996 Act amended Section 224 in several important ways to provide access to and rate regulation for pole attachments by cable operators and telecommunications carriers in order that they might compete in the market place to provide their respective services. The 1996 Act established a pole attachment rate methodology for telecommunications carriers that would not become effective until February 8, 2001. Until that time, pole attachments by telecommunications carriers will be regulated in the same manner as pole attachment rates for cable operators under Section 224(d). Prior to the 1996 Act, access to pole attachments was available only to cable operators and only under their franchise pursuant to Section 621. With the legislative expansion of access and rate regulation, small entities have greater opportunity to develop the infrastructure necessary to compete in the cable and telecommunications marketplaces. We have been mindful to maintain simplicity whenever possible, and to provide methodologies consistent with availability to publicly verifiable data. In the *Notice*, we sought comment to re-evaluate the formula methodologies used or proposed, to update our rules for accounting used in the formulas, and to provide a methodology for determining just and reasonable rates for pole attachments in conduit.

153. In accordance with the RFA, the Commission has endeavored to minimize significant impact on small entities. To minimize the burden on utility pole owners, including those that qualify as small entities, and to promote certainty and efficiency in determining the pole attachment rate for cable operators and telecommunications carriers, we have maintained our formula presumptions, including our one-foot presumption of space occupied by a pole attachment, and the presumptive amount of usable space on a pole.[437] We have adopted a conduit methodology based on publicly available data and a half-duct presumption of capacity occupied by a pole attachment in a conduit system, to simplify the process of determining a just and reasonable pole attachment rate and to provide certainty for small entities preparing to enter the competitive marketplace. We have formalized the use of part 32 accounting for LECs. We have consolidated all formula elements, and accounts specified for use in the formulas, in this one document in order to provide ease of application by all parties.

[437] *See* Section V.A above.

154. **Report to Congress:** The Commission will send a copy of the *Order*, including this FRFA, in a report to be sent to Congress pursuant to the Small Business Regulatory Enforcement Fairness Act of 1996, *see* 5 U.S.C. § 801(a)(1)(A). A copy of the *Order* and this FRFA (or summary thereof) will also be published in the Federal Register, *see* 5 U.S.C. § 604(b), and will be sent to the Chief Counsel for Advocacy of the Small Business Administration.

VIII. PAPERWORK REDUCTION ACT OF 1995 ANALYSIS

155. The requirements adopted in this *Order* have been analyzed with respect to the Paperwork Reduction Act of 1995 (the "1995 Act") and found to impose modified information collection requirements on the public. The Commission, as part of its continuing effort to reduce paperwork burdens, invites the general public to take this opportunity to comment on the information collection requirements contained in this *Order*, as required by the 1995 Act. Public comments are due 60 days from date of publication of this *Order* in the Federal Register. Comments should address: (1) whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (2) the accuracy of the Commission's burden estimates; (3) ways to enhance the quality, utility, and clarity of the information collected; and (4) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

156. As stated above, written comments by the public on the modified information collection requirements are due 60 days from date of publication of this *Order* in the Federal Register. Comments on the information collections contained herein should be submitted to Judy Boley, Federal Communications Commission, Room 234, 1919 M Street, NW, Washington, DC 20554, or via the Internet to jboley@fcc.gov. For additional information on the information collection requirements, contact Judy Boley at 202-418-0214 or via the Internet at the above address.

IX. ORDERING CLAUSES

157. IT IS ORDERED that, pursuant to Sections 1, 4(i), 224 and 303(r) of the Communications Act of 1934, as amended, 47 U.S.C. §§ 151, 154(i), 224 and 303(r), the Commission's rules are hereby amended as set forth in Appendix A.

158. IT IS FURTHER ORDERED that Section 1.1402 of the Commission's rules, as amended in Appendix A hereto, will become effective 30 days after the date of publication of this *Report and Order* in the Federal Register, and that Sections 1.1404 and 1.1409 of the Commission's rules, as amended in Appendix A hereto, will become effective 140 days after the date of publication of this *Report and Order* in the Federal Register, unless the Commission publishes a notice before that date stating that the Office of Management and Budget ("OMB") has not approved the information collection requirements contained in the rules.

159. IT IS FURTHER ORDERED that the Commission's Office of Public Affairs, Reference Operations Division, SHALL SEND a copy of this *Report and Order*, including the Final Regulatory

Flexibility Analyses, to the Chief Counsel for Advocacy of the Small Business Administration.

FEDERAL COMMUNICATIONS COMMISSION

Magalie Roman Salas
Secretary

APPENDIX A

Revised Rules

Part 1 of Title 47 of the Code of Federal Regulations is amended as follows:

PART 1 — PRACTICE AND PROCEDURE

1. The authority citation for Part 1 continues to read as follows:

AUTHORITY: 47 U.S.C. 151, 154(i), 154(j), 155, 225, 303(r) and 309.

2. Amend § 1.1402 to revise paragraphs (c), (i), (j) and (l) and add paragraph (n) to read as follows:

§ 1.1402 Definitions.

* * * * *

(c) With respect to poles, the term usable space means the space on a utility pole above the minimum grade level which can be used for the attachment of wires, cables, and associated equipment, and which includes space occupied by the utility. With respect to conduit, the term usable space means capacity within a conduit system which is available, or which could, with reasonable effort and expense, be made available, for the purpose of installing wires, cable and associated equipment for telecommunications or cable services, and which includes capacity occupied by the utility.

* * * * *

(i) The term conduit means a structure containing one or more ducts, usually placed in the ground, in which cables or wires may be installed.

(j) The term conduit system means a collection of one or more conduits together with their supporting infrastructure.

* * * * *

(l) With respect to poles, the term unusable space means the space on a utility pole below the usable space, including the amount required to set the depth of the pole.

* * * * *

(n) The term inner-duct means a duct-like raceway smaller than a duct that is inserted into a duct so that the duct may carry multiple wires or cables.

* * * * *

3. Amend § 1.1404 to remove paragraph (k), and redesignate old paragraphs (l) (m) and (n) as (k), (l), and (m), respectively; revise the first sentence of paragraph (g), paragraphs (g)(10), (g)(13), the last (unnumbered) paragraph of paragraph (g); revise paragraph (h); and revise paragraph (j), to read as

follows:

§ 1.1404 Complaint.

* * * * *

(g) For attachments to poles, where it is claimed that either a rate is unjust or unreasonable, or a term or condition is unjust or unreasonable and examination of such term or condition requires review of the associated rate, the complaint shall provide data and information in support of said claim. * * *

* * * * *

(10) The rate of return authorized for the utility for intrastate service. With its pleading, the utility shall file a copy of the latest decision of the state regulatory body or state court which establishes this authorized rate of return if the rate of return is at issue in the proceeding and shall note the section which specifically establishes this authorized rate and whether the decision is subject to further proceedings before the state regulatory body or a court. In the absence of a state authorized rate of return, the rate of return set by the Commission for local exchange carriers shall be used as a default rate of return.

* * * * *

(13) Reimbursements received from CATV operators and telecommunications carriers for non-recurring costs; and

Data and information should be based upon historical or original cost methodology, insofar as possible. Data should be derived from ARMIS, FERC 1, or other reports filed with state or federal regulatory agencies (identify source). Calculations made in connection with these figures should be provided to the complainant. The complainant shall also specify any other information and argument relied upon to attempt to establish that a rate, term, or condition is not just and reasonable.

* * * * *

(h) With respect to attachments within a duct or conduit system, where it is claimed that either a rate is unjust or unreasonable, or a term or condition is unjust or unreasonable and examination of such term or condition requires review of the associated rate, the complaint shall provide data and information in support of said claim. The data and information shall include, where applicable:

(1) The gross investment by the utility for conduit;
(2) The accumulated depreciation from the gross conduit investment;
(3) The system duct length or system conduit length and the method used to determine it;
(4) The length of the conduit subject to the complaint;
(5) The number of ducts in the conduit subject to the complaint;
(6) The number of inner-ducts in the duct occupied, if any. If there are no inner-ducts, the attachment is presumed to occupy one-half duct.
(7) The annual carrying charges attributable to the cost of owning conduit. These charges may be expressed as a percentage of the net linear cost of a conduit. With its pleading, the utility shall file a copy of the latest decision of the state regulatory body or state court which determines the treatment of

accumulated deferred taxes if it is at issue in the proceeding and shall note the section which specifically determines the treatment and amount of accumulated deferred taxes.

(8) The rate of return authorized for the utility for intrastate service. With its pleading, the utility shall file a copy of the latest decision of the state regulatory body or state court which establishes this authorized rate of return if the rate of return is at issue in the proceeding and shall note the section which specifically establishes this authorized rate and whether the decision is subject to further proceedings before the state regulatory body or a court. In the absence of a state authorized rate of return, the rate of return set by the Commission for local exchange carriers shall be used as a default rate of return; and

(9) Reimbursements received by utilities from CATV operators and telecommunications carriers for non-recurring costs; and

Data and information should be based upon historical or original cost methodology, insofar as possible. Data should be derived from ARMIS, FERC 1, or other reports filed with state or federal regulatory agencies (identify source). Calculations made in connection with these figures should be provided to the complainant. The complainant shall also specify any other information and argument relied upon to attempt to establish that a rate, term, or condition is not just and reasonable.

* * * * *

(j) ***A utility must supply a cable television operator or telecommunications carrier the information required in paragraph (g), (h) or (i) of this section, as applicable, along with the supporting pages from its ARMIS, FERC Form 1, or other report to a regulatory body, within 30 days of the request by the cable television operator or telecommunications carrier.***

(k) The complaint shall include a brief summary of all steps taken to resolve the problem prior to filing. If no such steps were taken, the complaint shall state the reason(s) why it believed such steps were fruitless.

(l) Factual allegations shall be supported by affidavit of a person or persons with actual knowledge of the facts, and exhibits shall be verified by the person who prepares them.

(m) In a case where a cable television system operator or telecommunications carrier claims that it has been denied access to a pole, duct, conduit or right-of-way despite a request made pursuant to section 47 U.S.C. § 224(f), the complaint shall be filed within 30 days of such denial. In addition to meeting the other requirements of this section, the complaint shall include the data and information necessary to support the claim, including:

(1) The reasons given for the denial of access to the utility's poles, ducts, conduits and rights-of-way;

(2) The basis for the complainant's claim that the denial of access is improper;

(3) The remedy sought by the complainant;

(4) A copy of the written request to the utility for access to its poles, ducts, conduits or rights-of-way; and

(5) A copy of the utility's response to the written request including all information given by the utility to support its denial of access. A complaint alleging improper denial of access will not be dismissed if the complainant is unable to obtain a utility's written response, or if the utility denies the complainant any other information needed to establish a prima facie case.

* * * * *

4. Amend § 1.1409 to revise paragraph (e)(1); add new paragraph (e)(3) and redesignate old paragraph (e)(3) as paragraph (e)(4); and revise paragraph (f) to read as follows:

§ 1.1409 Commission consideration of the complaint.

* * * * *

(e) * * *

(1) The following formula shall apply to attachments to poles by cable operators providing cable services. This formula shall also apply to attachments to poles by any telecommunications carrier (to the extent such carrier is not a party to a pole attachment agreement) or cable operator providing telecommunications services until February 8, 2001:

$$\text{Maximum Rate} = \frac{\text{Space Occupied by Attachment}}{\text{Total Usable Space}} \times \text{Net Cost of a Bare Pole} \times \text{Carrying Charge Rate}$$

* * * * *

(3) The following formula shall apply to attachments to conduit by cable operators providing cable services. This formula shall also apply to attachments to conduit by any telecommunications carrier (to the extent such carrier is not a party to a pole attachment agreement) or cable operator providing telecommunications services until February 8, 2001:

$$\text{Maximum Rate} = \underbrace{\left[\frac{1}{\text{Number of Ducts}} \times \frac{1\text{ Duct}}{\text{No. of Inner Ducts}}\right]}_{\text{(Percentage of Conduit Capacity)}} \times \underbrace{\left[\text{No. of Ducts} \times \frac{\text{Net Conduit Investment}}{\text{System Duct Length}}\right]}_{\text{(Net Linear Cost of a Conduit)}} \times \text{Carrying Charge Rate}$$

If no inner-duct is installed the fraction, "1 Duct divided by the No. of Inner-Ducts" is presumed to be ½.

(4) Subject to paragraph (f) the following formula shall apply to pole attachments within a conduit system beginning on February 8, 2001:

Maximum Conduit Rate = Conduit Unusable Space Factor + Conduit Usable Space Factor

For purposes of this formula, the conduit unusable space factor, as defined under Section 1.1417(c), and the conduit usable space factor, as defined under Section 1.1418(c), shall apply to each linear foot occupied.

(f) Paragraphs (e)(2) and (e)(4) of this section shall become effective February 8, 2001 (i.e., five years after the effective date of the Telecommunications Act of 1996). Any increase in the rates for pole attachments that result from the adoption of such regulations shall be phased in over a period of five years beginning on the effective date of such regulations in equal annual increments. The five-year phase-in is to apply to rate increases only. Rate reductions are to be implemented immediately. The determination of any rate increase shall be based on data currently available at the time of the calculation of the rate increase.

APPENDIX B
List of Commenters

Note: If no abbreviation appears in parentheses following the full name of the party, the full name is used in this *Order*.

Comments in CS Docket No. 97-98

American Electric Power Service Corporation, Commonwealth Edison Company, Duke Energy Corporation and Florida Power and Light Company (American Electric)
Ameritech
Association for Local Telecommunications Services
AT&T Corp. (AT&T)
Bell Atlantic & NYNEX (Bell Atlantic/NYNEX)
BellSouth Corporation (BellSouth)
Carolina Power & Light Company, Delmarva Power & Light Company, Atlantic City Electric Company, Entergy Services, Florida Power Corporation, Pacific Gas and Electric Company, Potomac Electric Power Company, Public Service Company of Colorado, Southern Company, Georgia Power, Alabama Power, Gulf Power, Mississippi Power, Savannah Electric, Tampa Electric Company and Virginia Power, including North Carolina Power (Carolina Power)
Consolidated Edison Company of New York, Inc. (ConEd)
Duquesne Light Company (Duquesne Light)
Edison Electric Institute and UTC, the Telecommunications Association (Edison Electric/UTC)
GTE Service Corporation (GTE)
MCI Telecommunications Corporation (MCI)
National Cable Television Association, Cable Telecommunications Association, Texas Cable & Telecommunications Association, Cable Television Association of Georgia, South Carolina Cable Television Association, Cable Television Association of Maryland, Delaware and the District of Columbia, Mississippi Cable Telecommunications Association, Mid-America Cable Telecommunications Association, Kansas Cable Telecommunications Association, Jones Intercable, Inc., Charter Communications, Greater Media, Inc., Prime Cable, Rifkin & Associates, TCA Cable TV, Inc., and The Helicon Corporation (NCTA)
Ohio Edison Company (Ohio Edison)
Public Service Company of New Mexico (Public Service of New Mexico)
SBC Communications Inc. (SBC)
Small Cable Business Association (SBCA)
Southeastern Indiana Rural Electric Membership Cooperative (Southeastern Indiana REMC)
Southern New England Telephone Company (SNET)
Sprint Local Telephone Companies (Sprint)
Tele-Communications, Inc. (TCI)
Time Warner Cable (Time Warner)
Union Electric Company (Union Electric)
United States Telephone Association (USTA)
U S West, Inc. (U S West)
WorldCom, Inc. (WorldCom)

Reply Comments in CS Docket No. 97-98

American Electric Power Service Corporation, Commonwealth Edison Company, Duke Energy Corporation and Florida Power and Light Company (American Electric)
Ameritech
AT&T Corp. (AT&T)
Bell Atlantic & NYNEX (Bell Atlantic/NYNEX)
Carolina Power & Light Company, Delmarva Power & Light Company, Atlantic City Electric Company, Entergy Services, Florida Power Corporation, Pacific Gas and Electric Company, Potomac Electric Power Company, Public Service Company of Colorado, Southern Company, Georgia Power, Alabama Power, Gulf Power, Mississippi Power, Savannah Electric, Tampa Electric Company and Virginia Power, including North Carolina Power (Carolina Power)
Chugach Electric Association (Chugach)
Edison Electric Institute and UTC, the Telecommunications Association (Edison Electric/UTC)
GTE Service Corporation (GTE)
KMC Telecom Inc. (KMC Telecom)
MCI Telecommunications Corporation (MCI)
National Cable Television Association, Cable Telecommunications Association, Texas Cable & Telecommunications Association, Cable Television Association of Georgia, South Carolina Cable Television Association, Cable Television Association of Maryland, Delaware and the District of Columbia, Mississippi Cable Telecommunications Association, Mid-America Cable Telecommunications Association, Kansas Cable Telecommunications Association, Jones Intercable, Inc., Charter Communications, Greater Media, Inc., Prime Cable, Rifkin & Associates, TCA Cable TV, Inc., and The Helicon Corporation (NCTA)
National Telephone Cooperative Association
Qwest
SBC Communications Inc. (SBC)
Tele-Communications, Inc. (TCI)
Time Warner Cable (Time Warner)
United States Telephone Association (USTA)
U S West, Inc. (U S West)
WorldCom, Inc. (WorldCom)

Ex Parte Communications by Parties Not Previously Filing Comments
New England Electric Systems (NEES)

APPENDIX C - 1
Pole Attachment Formulas (Poles) For Local Exchange Carrier (LEC) Pole Owners Using FCC ARMIS Part 32 Accounts

$$\textbf{Maximum Rate per Pole} = \frac{\textbf{Space Occupied}}{\textbf{Usable Space}} \times \frac{\textbf{Net Pole Investment}}{\textbf{Total Number of Poles}} \times 0.95 \times \textbf{Carrying Charge Rate}$$

Where:

$$\textbf{Space Occupied} = \text{1 foot (presumed, but rebuttable)}$$

$$\textbf{Usable Space} = \text{13.5 feet (presumed, but rebuttable)}$$

$$\textbf{Net Pole Investment} = \begin{array}{c}\text{Gross Pole} \\ \text{Investment} \\ \text{(Account 2411)}\end{array} - \begin{array}{c}\text{Accumulated} \\ \text{Depreciation} \\ \text{(Account 3100)(Poles)}\end{array} - \begin{array}{c}\text{Accumulated Deferred} \\ \text{Income Taxes} \\ \text{(Account 4100 + 4340)(Poles)}\end{array}$$

$$\textbf{Carrying Charge Rate} = \text{Administrative + Maintenance + Depreciation + Taxes + Return}$$

$$\text{Administrative Element} = \frac{\text{Total General and Administrative (Accounts 6710 \& 6720)}}{\begin{array}{c}\text{Gross Plant Investment} \\ \text{(Account 2001)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation} \\ \text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred} \\ \text{Taxes (Plant) (Accounts 4100 + 4340)}\end{array}}$$

$$\text{Maintenance Element} = \frac{\text{Account 6411} - \text{Rental Expense (Poles)}}{\text{Net Pole Investment}}$$

$$\text{Depreciation Element} = \frac{\text{Gross Pole Investment (Account 2411)}}{\text{Net Pole Investment}} \times \begin{array}{c}\text{Depreciation Rate} \\ \text{for Gross Pole Investment}\end{array}$$

$$\text{Taxes Element} = \frac{\text{Operating Taxes (Account 7200)}}{\begin{array}{c}\text{Gross Plant Investment} \\ \text{(Account 2001)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation} \\ \text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred} \\ \text{Taxes (Plant) (Accounts 4100 + 4340)}\end{array}}$$

$$\text{Return Element} = \text{Applicable Rate of Return (default} \equiv \text{11.25\%)}$$

Appendix C - 2
Pole Attachment Formulas (Poles) For
Electric Utility Pole Owners Using FERC Part 101 Accounts

$$\textbf{Maximum Rate per Pole} = \frac{\textbf{Space Occupied}}{\textbf{Usable Space}} \times \frac{\textbf{Net Pole Investment}}{\textbf{Total Number of Poles}} \times 0.85 \times \textbf{Carrying Charge Rate}$$

Where:

$$\textbf{Space Occupied} = \text{1 foot (presumed, but rebuttable)}$$

$$\textbf{Usable Space} = \text{13.5 feet (presumed, but rebuttable)}$$

$$\textbf{Net Pole Investment} = \text{Gross Pole Investment (Account 364)} - \text{Accumulated Depreciation (Account 108)(Poles)} - \text{Accumulated Deferred Income Taxes (Account 109)(Poles)}$$

$$\textbf{Carrying Charge Rate} = \text{Administrative} + \text{Maintenance} + \text{Depreciation} + \text{Taxes} + \text{Return}$$

$$\text{Administrative Element} = \frac{\text{Total General and Administrative (FERC Form 1, p. 323, line 168, col. b.)}}{\text{Gross Plant Investment (FERC Form 1, p. 200, col. b)} - \text{Accumulated Depreciation (Account 108)} - \text{Accumulated Deferred Taxes (Plant) (Account 190)}}$$

$$\text{Maintenance Element} = \frac{\text{Account 593}}{\text{Pole Investment in Accounts 364, 365, \& 369} - \text{Depreciation (Poles) Related to Accounts 364, 365, \& 369} - \text{Accumulated Deferred Income Taxes related to Accounts 364, 365, \& 369}}$$

$$\text{Depreciation Element} = \frac{\text{Gross Pole Investment (Account 364)}}{\text{Net Pole Investment}} \times \text{Depreciation Rate for Gross Pole Investment}$$

$$\text{Taxes Element} = \frac{\text{Accounts } 408.1 + 409.1 + 410.1 + 411.4 - 411.1}{\text{Gross Plant Investment (FERC Form 1, p. 200, col. b)} - \text{Accumulated Depreciation (Account 108)} - \text{Accumulated Deferred Taxes (Plant) (Account 190)}}$$

$$\text{Return Element} = \text{Applicable Rate of Return (default} \equiv 11.25\%)$$

APPENDIX C -3
Pole Attachment Formulas (Conduit) For Local Exchange Carrier (LEC) Conduit Owners Using FCC ARMIS Part 32 Accounts

$$\textbf{Maximum Rate} = \begin{array}{c}\textbf{Percentage of}\\ \textbf{Conduit Capacity}\\ \textbf{Occupied}\end{array} \times \begin{array}{c}\textbf{Net Linear Cost}\\ \textbf{of Conduit}\end{array} \times \begin{array}{c}\textbf{Carrying}\\ \textbf{Charge}\\ \textbf{Rate}\end{array}$$

Where:

$$\begin{array}{c}\textbf{Percentage of}\\ \textbf{Conduit Capacity}\\ \textbf{Occupied}\end{array} = \frac{1}{\begin{array}{c}\text{Number of}\\ \text{Inner Ducts}\end{array}(\geq 2)} \times \frac{1}{\begin{array}{c}\text{Number of Ducts}\\ \text{in Conduit}\end{array}}$$

$$\begin{array}{c}\textbf{Net Linear Cost}\\ \textbf{of Conduit}\end{array} = \begin{array}{c}\text{Number of Ducts}\\ \text{in Conduit}\end{array} \times \frac{\begin{array}{c}\text{Net Conduit}\\ \text{Investment}\end{array}}{\begin{array}{c}\text{Total Conduit System}\\ \text{Duct Length (ft. or m.)}\end{array}} \text{ OR } = \frac{\begin{array}{c}\text{Net Conduit}\\ \text{Investment}\end{array}}{\begin{array}{c}\text{Total Length of Conduit}\\ \text{in System}\end{array}}$$

$$\text{Net Conduit Investment} = \begin{array}{c}\text{Gross Conduit Investment}\\ \text{(Account 2441)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation}\\ \text{(Account 3100)(Conduit)}\end{array} - \begin{array}{c}\text{Accumulated Deferred}\\ \text{Income Taxes}\\ \text{(Account 4100 + 4340)(Conduit)}\end{array}$$

$$\begin{array}{l}\textbf{Carrying}\\ \textbf{Charge Rate}\end{array} = \text{Administrative} + \text{Maintenance} + \text{Depreciation} + \text{Taxes} + \text{Return}$$

$$\begin{array}{c}\text{Administrative}\\ \text{Element}\end{array} = \frac{\text{Total General and Administrative Expenses (Accounts 6710 \& 6720)}}{\begin{array}{c}\text{Gross Plant Investment}\\ \text{(Account 2001)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation}\\ \text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred}\\ \text{Taxes (Plant) (Accounts 4100 + 4340)}\end{array}}$$

$$\begin{array}{c}\text{Maintenance}\\ \text{Element}\end{array} = \frac{\text{Conduit Maintenance Expense (Account 6441)}}{\text{Net Conduit Investment}}$$

$$\begin{array}{c}\text{Depreciation}\\ \text{Element}\end{array} = \frac{\text{Gross Conduit Investment (Account 2441)}}{\text{Net Conduit Investment}} \times \begin{array}{c}\text{Depreciation Rate}\\ \text{for Conduit}\end{array}$$

$$\begin{array}{c}\text{Taxes}\\ \text{Element}\end{array} = \frac{\text{Operating Taxes (Account 7200)}}{\begin{array}{c}\text{Gross Plant Investment}\\ \text{(Account 2001)}\end{array} - \begin{array}{c}\text{Accumulated Depreciation}\\ \text{(Account 3100)}\end{array} - \begin{array}{c}\text{Accumulated Deferred}\\ \text{Taxes (Plant)}\\ \text{(Accounts 4100 + 4340)}\end{array}}$$

$$\begin{array}{c}\text{Return}\\ \text{Element}\end{array} = \text{Applicable Rate of Return (default} \equiv 11.25\%)$$

APPENDIX C - 4
Pole Attachment Formulas (Conduit) For Electric Utility Conduit Owners Using FERC Part 101 Accounts

$$\textbf{Maximum Rate} = \begin{matrix}\textbf{Percentage of}\\ \textbf{Conduit Capacity}\\ \textbf{Occupied}\end{matrix} \times \begin{matrix}\textbf{Net Linear Cost}\\ \textbf{of Conduit}\end{matrix} \times \begin{matrix}\textbf{Carrying}\\ \textbf{Charge}\\ \textbf{Rate}\end{matrix}$$

Where:

$$\begin{matrix}\textbf{Percentage of}\\ \textbf{Conduit Capacity}\\ \textbf{Occupied}\end{matrix} = \frac{1}{\begin{matrix}\text{Number of}\\ \text{Inner Ducts}\end{matrix}\ (\geq 2)} \times \frac{1}{\begin{matrix}\text{Number of Ducts}\\ \text{in Conduit}\end{matrix}}$$

$$\begin{matrix}\textbf{Net Linear Cost}\\ \textbf{of Conduit}\end{matrix} = \begin{matrix}\text{Number of Ducts}\\ \text{in Conduit}\end{matrix} \times \frac{\begin{matrix}\text{Net Conduit}\\ \text{Investment}\end{matrix}}{\begin{matrix}\text{Total Conduit System}\\ \text{Duct Length (ft. or m.)}\end{matrix}} \text{ OR } = \frac{\begin{matrix}\text{Net Conduit}\\ \text{Investment}\end{matrix}}{\begin{matrix}\text{Total Length of Conduit}\\ \text{in System}\end{matrix}}$$

$$\text{Net Conduit Investment} = \begin{matrix}\text{Gross Conduit Investment}\\ \text{(Account 366)}\end{matrix} - \begin{matrix}\text{Accumulated Depreciation}\\ \text{(Account 108)(Conduit)}\end{matrix} - \begin{matrix}\text{Accumulated Deferred}\\ \text{Income Taxes}\\ \text{(Account 109)(Conduit)}\end{matrix}$$

$$\begin{matrix}\textbf{Carrying}\\ \textbf{Charge Rate}\end{matrix} = \text{Administrative} + \text{Maintenance} + \text{Depreciation} + \text{Taxes} + \text{Return}$$

$$\begin{matrix}\text{Administrative}\\ \text{Element}\end{matrix} = \frac{\text{Total General and Administrative Expenses (FERC Form 1, p. 323, line 168, col. b)}}{\begin{matrix}\text{Gross Plant Investment}\\ \text{(FERC Form 1, p. 200, col. b)}\end{matrix} - \begin{matrix}\text{Accumulated Depreciation}\\ \text{(Account 108)}\end{matrix} - \begin{matrix}\text{Accumulated Deferred}\\ \text{Taxes (Plant) (Account 190)}\end{matrix}}$$

$$\begin{matrix}\text{Maintenance}\\ \text{Element}\end{matrix} = \frac{\text{Account 594}}{\begin{matrix}\text{Conduit Investment in}\\ \text{Accounts 366, 367, \& 369}\end{matrix} - \begin{matrix}\text{Depreciation (Poles) in}\\ \text{Accounts 366, 367, \& 369}\end{matrix} - \begin{matrix}\text{Accumulated Deferred}\\ \text{Income Taxes related to}\\ \text{Accounts 366, 367, \& 369}\end{matrix}}$$

$$\begin{matrix}\text{Depreciation}\\ \text{Element}\end{matrix} = \frac{\text{Gross Conduit Investment (Account 366)}}{\text{Net Conduit Investment}} \times \begin{matrix}\text{Depreciation Rate}\\ \text{for Conduit}\end{matrix}$$

$$\begin{matrix}\text{Taxes}\\ \text{Element}\end{matrix} = \frac{\text{Accounts } 408.1 + 409.1 + 410.1 + 411.4 - 411.1}{\begin{matrix}\text{Gross Plant Investment}\\ \text{(FERC Form 1, p. 200, col. b)}\end{matrix} - \begin{matrix}\text{Accumulated Depreciation}\\ \text{(Account 108)}\end{matrix} - \begin{matrix}\text{Accumulated Deferred Taxes (Plant)}\\ \text{(Account 190)}\end{matrix}}$$

$$\begin{matrix}\text{Return}\\ \text{Element}\end{matrix} = \text{Applicable Rate of Return (default} \equiv 11.25\%)$$

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 93

Responding Witness: William S. Seelye

Q-93. Refer to the Seelye Testimony, page 63, lines 1-11.

a. Explain why the charge listed as (2) would be necessary given the proposed AMS.

b. Explain why the charge listed as (3) would be necessary given the proposed AMS.

A-93.

a. The charge applies to meter tampering involving the replacement of a damaged standard meter. The charge will be necessary until all standard meters are replaced with AMS meters.

b. The charge applies to meter tampering involving the replacement of a damaged AMR meter. The charge will be necessary until all AMR meters are replaced with AMS meters.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 94

Responding Witness: Robert M. Conroy / William S. Seelye

Q-94. Refer to the Seelye Testimony, page 63, lines 16-22.

a. Given that KU is currently recovering its out-of-pocket costs from customers who tamper with their meters, explain the necessity of establishing the proposed Unauthorized Reconnection Charges.

b. Explain whether this testimony indicates that the forecasted test year includes both expenses associated with tampering as well as revenues collected from customers, and in amounts identical to what is proposed through the Unauthorized Reconnection Charges.

A-94.

a. The purpose of the Unauthorized Reconnection Charges is at least twofold: (1) to ensure uniformity of charges for certain components of damage caused by unauthorized reconnections; and (2) to put customers on notice of at least some of the charges they will incur if they engage in an unauthorized reconnection.

b. Yes. The forecasted test year includes the actual charges for meter tampering as proposed to be recovered through the proposed Unauthorized Reconnection Charges. The Company is currently charging customers for unauthorized reconnections on an out-of-pocket expense basis. The proposed tariffed charge is designed to recover the same amount of costs currently being collected from customers.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 95

Responding Witness: William S. Seelye

Q-95. Refer to the Seelye Testimony, page 64, lines 15- 17. State whether all balance sheet and income statement accounts in the modified Base-Intermediate-Peak ("BIP") COSS, including the jurisdictional separation study, have been allocated using the same methodology and allocation factors as used in the most recent base rate proceeding. If not, provide the changes and the reasons for the changes.

A-95. Yes, all production income and balance sheet accounts have been allocated using the same methodology as used in the Company's most recent base rate proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 96

Responding Witness: David S. Sinclair / William S. Seelye

Q-96. Refer to the Seelye Testimony, page 67. For the most recent five-year period, provide the summer and winter peaks for KU, LG&E, and the Companies combined.

A-96. See attached.

WINTER

	Combined	LG&E	KU
2012	5,704	1,812	4,014
2013	5,907	1,989	4,193
2014	7,114	2,096	5,068
2015	7,079	1,976	5,112
2016	6,223	1,970	4,415

SUMMER

	Combined	LG&E	KU
2012	6,856	2,731	4,138
2013	6,434	2,529	3,943
2014	6,313	2,481	3,870
2015	6,392	2,594	3,865
2016	6,458	2,543	3,936

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 97

Responding Witness: William S. Seelye

Q-97. Refer to the Seelye Testimony, page 69, lines 4-7. Explain in detail how the LOLP was calculated for each rate class using one hour of the test year as an example.

A-97. To calculate the LOLP allocator for a single hour, the LOLP for the hour is multiplied by the class demands for the hour. In the following example, the LOLP for hour 15 of August 9 of the test year is multiplied by the class demands for the hour:

Rate Class	LOLP for Hour	Load	LOLP * Load
	0.00126025		
Residential		1,347,050.57	1,697.62
General Service		403,388.94	508.37
All Electric Schools		27,081.46	34.13
PS Primary		31,910.02	40.21
PS Secondary		425,406.22	536.12
TOD Primary		686,212.74	864.80
TOD Secondary		313,580.28	395.19
RTS		255,097.03	321.49
FLS		96,437.83	121.54
Unmetered Lighting		-	-
Traffic Energy Svc		170.38	0.21
Lighting Energy Svc		-	-
Total		**3,586,335.49**	**4,519.68**

In the study, the LOLP weighted hourly demands are then summed to determine the allocation factor for production fixed costs.

See the attachment being provided in Excel format, which calculates the hourly demand weighted LOLPs and the development of the demand allocators for the test year.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 98

Responding Witness: Christopher M. Garrett / William S. Seelye

Q-98. Refer to the Seelye Testimony, Exhibit WSS-2.

a. Provide the supporting calculation for the "ECR Base Rates" of $.006770.

b. Provide the "Unit Cost of Service Based on the Cost of Service Study" for each rate class using the BIP COSS. Provide the response in Excel spreadsheet format with the formulas intact and unprotected.

c. Provide the "Unit Cost of Service Based on the Cost of Service Study" for each rate class using the LOLP COSS. Provide the response in Excel spreadsheet format with the formulas intact and unprotected.

A-98.

a. This unit charge represents the current amount of ECR costs that have been rolled-in to base rates that are included in the current rates charged by the Company approved in Case No. 2015-00221. Specifically, this was eFiled as Exhibit 2 (on page 2 of 6) on December 16, 2015 file "3-KU ECR Rollin Supporting Calculations.pdf." See attached for ease of reference.

b. See the attachment being provided in Excel format.

c. See the attachment being provided in Excel format.

KENTUCKY UTILITIES COMPANY

Group 1 ECR Rollin Calculations

Using Regenerated Revenues for the Twelve Months Ending September 30, 2015

Case No. 2015-00221

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Rate Class	12-Month Lighting Installations	12-Month Energy	kW per Light	Energy Rate -- ECR	Lighting Rate -- ECR	Base Fuel Revenue	ECR Energy Revenue	ECR Lighting Revenue	Total 12-Month ECR Revenue
								(3) x (5)	(2) x (6)	(8) + (9)
	Residential Service (except VFD)		6,277,551,280		$ 0.00315		$ 181,546,783	$ 19,774,286.53		$ 19,774,286.53
	Volunteer Fire Departments (charged at Rate RS)		1,214,675		$ 0.00315		$ 35,128	$ 3,826.23		$ 3,826.23
	All Electric Schools		150,884,364		$ 0.00315		$ 4,363,576	$ 475,285.75		$ 475,285.75
	Low Emission Vehicle Period 1 and RTOD-Energy Off-Peak		84,974		$ 0.00315		$ 3,640	$ 420.57		$ 420.57
	Low Emission Vehicle, Period 2		29,123		$ 0.00315					
	Low Emission Vehicle, Period 3 and RTOD-Energy Peak		19,418		$ 0.00315					
	RTOD-Demand (no Customers on rate at this time)		-		$ 0.00315		-	$ -		$ -
	Lighting Energy Service		337,137		$ 0.00315		$ 9,750	$ 1,061.98		$ 1,061.98
	Traffic Energy Service		1,463,215		$ 0.00315		$ 42,316	$ 4,609.13		$ 4,609.13
	Sheet No. 35									
462	HPS Cobra Head, 5800 Lumen, Fixture Only	105,287	2,919,957	0.083		$ 0.43	$ 84,229.60	$ -	$ 45,273.41	$ 45,273.41
472	HPS Cobra Head, 5800 Lumen, Fixture with Ornamental Pole	107,247	2,982,103	0.083		$ 0.43	$ 85,797.60	$ -	$ 46,116.21	$ 46,116.21
463	HPS Cobra Head, 9500 Lumen, Fixture Only	249,099	9,737,224	0.117		$ 0.34	$ 281,481.87	$ -	$ 84,693.66	$ 84,693.66
473	HPS Cobra Head, 9500 Lumen, Fixture with Ornamental Pole	40,681	1,592,227	0.117		$ 0.34	$ 45,969.53	$ -	$ 13,831.54	$ 13,831.54
464	HPS Cobra Head, 22000 Lumen, Fixture Only	92,049	7,430,797	0.242		$ 0.58	$ 214,474.17	$ -	$ 53,388.42	$ 53,388.42
474	HPS Cobra Head, 22000 Lumen, Fixture with Ornamental Pole	62,454	5,053,760	0.242		$ 0.58	$ 145,517.82	$ -	$ 36,223.32	$ 36,223.32
465	HPS Cobra Head, 50000 Lumen, Fixture Only	33,008	5,186,351	0.471		$ 0.79	$ 149,526.24	$ -	$ 26,076.32	$ 26,076.32
475	HPS Cobra Head, 50000 Lumen, Fixture with Ornamental Pole	6,341	998,975	0.471		$ 0.79	$ 28,724.73	$ -	$ 5,009.39	$ 5,009.39
487	HPS Directional, 9500 Lumen, Fixture Only	133,138	5,167,393	0.117		$ 0.34	$ 150,445.94	$ -	$ 45,266.92	$ 45,266.92
488	HPS Directional, 22000 Lumen, Fixture Only	79,915	6,434,998	0.242		$ 0.58	$ 186,201.95	$ -	$ 46,350.70	$ 46,350.70
489	HPS Directional, 50000 Lumen, Fixture Only	101,002	15,899,609	0.471		$ 0.79	$ 457,539.06	$ -	$ 79,791.58	$ 79,791.58
428	HPS Open Bottom, 9500 Lumen, Fixture Only	440,088	17,061,029	0.117		$ 0.34	$ 497,299.44	$ -	$ 149,629.92	$ 149,629.92
450	MH Directional, 12000 Lumen, Fixture Only	8,433	420,635	0.150		$ 0.66	$ 16,613.01	$ -	$ 5,565.78	$ 5,565.78
451	MH Directional, 32000 Lumen, Fixture Only	63,548	7,402,604	0.350		$ 0.84	$ 272,620.92	$ -	$ 53,380.32	$ 53,380.32
452	MH Directional, 107800 Lumen, Fixture Only	12,360	4,445,964	1.080		$ 1.70	$ 128,667.60	$ -	$ 21,012.00	$ 21,012.00
	Sheet No. 35.1									
467	HPS Colonial, 5800 Lumen, Decorative Smooth Pole	16,739	463,576	0.083		$ 0.43	$ 13,391.20	$ -	$ 7,197.77	$ 7,197.77
468	HPS Colonial, 9500 Lumen, Decorative Smooth Pole	48,865	1,904,969	0.117		$ 0.34	$ 55,217.45	$ -	$ 16,614.10	$ 16,614.10
401	HPS Acorn, 5800 Lumen, Decorative Smooth Pole	624	17,327	0.083		$ 0.43	$ 499.20	$ -	$ 268.32	$ 268.32
411	HPS Acorn, 5800 Lumen, Historic Fluted Pole	1,790	49,699	0.083		$ 0.43	$ 1,432.00	$ -	$ 769.70	$ 769.70
420	HPS Acorn, 9500 Lumen, Decorative Smooth Pole	6,105	238,850	0.117		$ 0.34	$ 6,898.65	$ -	$ 2,075.70	$ 2,075.70
430	HPS Acorn, 9500 Lumen, Historic Fluted Pole	14,650	571,934	0.117		$ 0.34	$ 16,554.50	$ -	$ 4,981.00	$ 4,981.00
414	HPS Victorian, 5800 Lumen, Historic Fluted Pole	252	6,990	0.083		$ 0.43	$ 201.60	$ -	$ 108.36	$ 108.36
415	HPS Victorian, 9500 Lumen, Historic Fluted Pole	120	4,691	0.117		$ 0.34	$ 135.60	$ -	$ 40.80	$ 40.80
492	HPS Contemporary, 5800 Lumen, Fixture Only	24	665	0.083		$ 0.43	$ 19.20	$ -	$ 10.32	$ 10.32
476	HPS Contemporary, 5800 Lumen, Decorative Smooth Pole	56,253	1,565,636	0.083		$ 0.43	$ 45,002.40	$ -	$ 24,188.79	$ 24,188.79
497	HPS Contemporary, 9500 Lumen, Fixture Only	213	8,248	0.117		$ 0.34	$ 240.69	$ -	$ 72.42	$ 72.42
477	HPS Contemporary, 9500 Lumen, Decorative Smooth Pole	12,158	490,123	0.117		$ 0.34	$ 13,738.54	$ -	$ 4,133.72	$ 4,133.72
498	HPS Contemporary, 22000 Lumen, Fixture Only	350	28,001	0.242		$ 0.58	$ 815.50	$ -	$ 203.00	$ 203.00
478	HPS Contemporary, 22000 Lumen, Decorative Smooth Pole	17,178	1,389,028	0.242		$ 0.58	$ 40,024.74	$ -	$ 9,963.24	$ 9,963.24
499	HPS Contemporary, 50000 Lumen, Fixture Only	413	64,521	0.471		$ 0.79	$ 1,870.89	$ -	$ 326.27	$ 326.27
479	HPS Contemporary, 50000 Lumen, Decorative Smooth Pole	11,305	1,779,720	0.471		$ 0.79	$ 51,211.65	$ -	$ 8,930.95	$ 8,930.95

KENTUCKY UTILITIES COMPANY

Group 1 ECR Rollin Calculations

Using Regenerated Revenues for the Twelve Months Ending September 30, 2015

Case No. 2015-00221

	(1) Rate Class	(11) Total 12-Month Revenue	(12) Total Revenue Excluding ECR	(13) ECR Revenue to Roll-in	(14) Proposed ECR Component of Rates -- Energy	(15) ECR Component of Monthly Per Light Rates	(16) Proposed Base ECR Revenue	(17) Difference Between Allocated ECR and Revised Revenue	(18) Revised Rates	(19) Existing Rates	(20) Percent Change
			(11) - (10)	See Summary	(13) ÷ (3)	(13) ÷ (2)	(14) x (3) or (15) x (2)	(13) - (16)			
	Residential Service (except VFD)	$ 550,542,629.32	$ 530,768,342.79	$ 42,505,160.25	$ 0.00677		$ 42,499,022.17	$ 6,138.08	$ 0.08870	$ 0.08508	4.25%
	Volunteer Fire Departments (charged at Rate RS)	$ 102,434.62	$ 98,608.39	$ 7,896.79	$ 0.00677		$ 8,223.35	$ (326.56)	$ 0.08870	$ 0.08508	4.25%
	All Electric Schools	$ 11,598,719.06	$ 11,123,433.31	$ 890,790.35	$ 0.00590		$ 890,217.75	$ 572.60	$ 0.08369	$ 0.08094	3.40%
	Low Emission Vehicle Period 1 and RTOD-Energy Off-Peak	$ 11,180.15	$ 10,759.58	$ 861.65	$ 0.00677		$ 575.27	$ 154.92	$ 0.05740	$ 0.05378	6.73%
	Low Emission Vehicle, Period 2										
	Low Emission Vehicle, Period 3 and RTOD-Energy Peak				$ 0.00677		$ 131.46		$ 0.27646	$ 0.27284	1.33%
	RTOD-Demand (no Customers on rate at this time)	$ -	$ -	$ -	$ 0.00677		$ -	$ -	$ 0.04370	$ 0.04008	9.03%
	Lighting Energy Service	$ 21,893.98	$ 20,832.00	$ 1,668.27	$ 0.00731		$ 2,464.47	$ (796.20)	$ 0.07328	$ 0.06912	6.02%
	Traffic Energy Service	$ 148,098.70	$ 143,489.57	$ 11,490.98	$ 0.00731		$ 10,696.10	$ 794.88	$ 0.08740	$ 0.08324	5.00%
	Sheet No. 35										
462	HPS Cobra Head, 5800 Lumen, Fixture Only	$ 925,868.66	$ 880,595.25	$ 70,520.11		$ 0.91	$ 95,811.17	$ (25,291.06)	$ 9.86	$ 9.38	5.12%
472	HPS Cobra Head, 5800 Lumen, Fixture with Ornamental Pole	$ 1,260,892.54	$ 1,214,776.33	$ 97,282.11		$ 0.91	$ 97,594.77	$ (312.66)	$ 13.04	$ 12.56	3.82%
463	HPS Cobra Head, 9500 Lumen, Fixture Only	$ 2,316,178.86	$ 2,231,485.20	$ 178,702.51		$ 0.72	$ 179,351.28	$ (648.77)	$ 10.28	$ 9.90	3.84%
473	HPS Cobra Head, 9500 Lumen, Fixture with Ornamental Pole	$ 507,619.23	$ 493,787.69	$ 39,543.66		$ 0.72	$ 29,290.32	$ 10,253.34	$ 13.70	$ 13.32	2.85%
464	HPS Cobra Head, 22000 Lumen, Fixture Only	$ 1,331,971.16	$ 1,278,582.74	$ 102,391.87		$ 1.23	$ 113,220.27	$ (10,828.40)	$ 16.08	$ 15.43	4.21%
474	HPS Cobra Head, 22000 Lumen, Fixture with Ornamental Pole	$ 1,102,887.28	$ 1,066,663.96	$ 85,420.92		$ 1.23	$ 76,818.42	$ 8,602.50	$ 19.50	$ 18.85	3.45%
465	HPS Cobra Head, 50000 Lumen, Fixture Only	$ 763,858.75	$ 737,782.43	$ 59,083.33		$ 1.67	$ 55,123.36	$ 3,959.97	$ 25.61	$ 24.73	3.56%
475	HPS Cobra Head, 50000 Lumen, Fixture with Ornamental Pole	$ 157,356.26	$ 152,346.87	$ 12,200.29		$ 1.67	$ 10,589.47	$ 1,610.82	$ 27.37	$ 26.49	3.32%
487	HPS Directional, 9500 Lumen, Fixture Only	$ 1,212,312.75	$ 1,167,045.83	$ 93,459.74		$ 0.72	$ 95,859.36	$ (2,399.62)	$ 10.13	$ 9.75	3.90%
488	HPS Directional, 22000 Lumen, Fixture Only	$ 1,104,673.87	$ 1,058,323.17	$ 84,752.97		$ 1.23	$ 98,295.45	$ (13,542.48)	$ 15.42	$ 14.77	4.40%
489	HPS Directional, 50000 Lumen, Fixture Only	$ 2,001,962.30	$ 1,922,170.72	$ 153,931.89		$ 1.67	$ 168,673.34	$ (14,741.45)	$ 21.95	$ 21.07	4.18%
428	HPS Open Bottom, 9500 Lumen, Fixture Only	$ 3,485,805.92	$ 3,336,176.00	$ 267,168.71		$ 0.72	$ 316,863.36	$ (49,694.65)	$ 8.87	$ 8.49	4.48%
450	MH Directional, 12000 Lumen, Fixture Only	$ 121,638.25	$ 116,072.47	$ 9,295.35		$ 1.36	$ 11,468.88	$ (2,173.53)	$ 16.13	$ 15.43	4.54%
451	MH Directional, 32000 Lumen, Fixture Only	$ 1,301,718.85	$ 1,248,338.53	$ 99,969.85		$ 1.77	$ 112,479.96	$ (12,510.11)	$ 22.80	$ 21.87	4.25%
452	MH Directional, 107800 Lumen, Fixture Only	$ 530,453.08	$ 509,441.08	$ 40,797.22		$ 3.54	$ 43,754.40	$ (2,957.18)	$ 47.70	$ 45.86	4.01%
	Sheet No. 35.1										
467	HPS Colonial, 5800 Lumen, Decorative Smooth Pole	$ 183,208.04	$ 176,010.27	$ 14,095.31		$ 0.91	$ 15,232.49	$ (1,137.18)	$ 12.14	$ 11.66	4.12%
468	HPS Colonial, 9500 Lumen, Decorative Smooth Pole	$ 553,687.95	$ 537,073.85	$ 43,010.12		$ 0.72	$ 35,182.80	$ 7,827.32	$ 12.46	$ 12.08	3.15%
401	HPS Acorn, 5800 Lumen, Decorative Smooth Pole	$ 9,429.44	$ 9,161.12	$ 733.64		$ 0.91	$ 567.84	$ 165.80	$ 16.57	$ 16.09	2.98%
411	HPS Acorn, 5800 Lumen, Historic Fluted Pole	$ 38,898.45	$ 38,128.75	$ 3,053.44		$ 0.91	$ 1,628.90	$ 1,424.54	$ 23.63	$ 23.15	2.07%
420	HPS Acorn, 9500 Lumen, Decorative Smooth Pole	$ 95,433.51	$ 93,357.81	$ 7,476.31		$ 0.72	$ 4,395.60	$ 3,080.71	$ 17.01	$ 16.63	2.29%
430	HPS Acorn, 9500 Lumen, Historic Fluted Pole	$ 327,491.61	$ 322,510.61	$ 25,827.40		$ 0.72	$ 10,548.00	$ 15,279.40	$ 24.20	$ 23.82	1.60%
414	HPS Victorian, 5800 Lumen, Historic Fluted Pole	$ 7,876.93	$ 7,768.57	$ 622.13		$ 0.91	$ 229.32	$ 392.81	$ 33.87	$ 33.39	1.44%
415	HPS Victorian, 9500 Lumen, Historic Fluted Pole	$ 3,797.31	$ 3,756.51	$ 300.83		$ 0.72	$ 86.40	$ 214.43	$ 34.19	$ 33.81	1.12%
492	HPS Contemporary, 5800 Lumen, Fixture Only	$ 375.89	$ 365.57	$ 29.28		$ 0.91	$ 21.84	$ 7.44	$ 17.12	$ 16.64	2.88%
476	HPS Contemporary, 5800 Lumen, Decorative Smooth Pole	$ 957,759.65	$ 933,570.86	$ 74,762.52		$ 0.91	$ 51,190.23	$ 23,572.29	$ 18.66	$ 18.18	2.64%
497	HPS Contemporary, 9500 Lumen, Fixture Only	$ 3,300.63	$ 3,228.21	$ 258.52		$ 0.72	$ 153.36	$ 105.16	$ 17.00	$ 16.62	2.29%
477	HPS Contemporary, 9500 Lumen, Decorative Smooth Pole	$ 266,572.73	$ 262,439.01	$ 21,016.72		$ 0.72	$ 8,753.76	$ 12,262.96	$ 23.09	$ 22.71	1.67%
498	HPS Contemporary, 22000 Lumen, Fixture Only	$ 6,286.89	$ 6,083.89	$ 487.21		$ 1.23	$ 430.50	$ 56.71	$ 19.84	$ 19.19	3.39%
478	HPS Contemporary, 22000 Lumen, Decorative Smooth Pole	$ 468,291.68	$ 458,328.44	$ 36,704.00		$ 1.23	$ 21,128.94	$ 15,575.06	$ 29.73	$ 29.08	2.24%
499	HPS Contemporary, 50000 Lumen, Fixture Only	$ 9,006.23	$ 8,679.96	$ 695.11		$ 1.67	$ 689.71	$ 5.40	$ 24.15	$ 23.27	3.78%
479	HPS Contemporary, 50000 Lumen, Decorative Smooth Pole	$ 380,162.12	$ 371,231.17	$ 29,729.05		$ 1.67	$ 18,879.35	$ 10,849.70	$ 36.74	$ 35.86	2.45%

KENTUCKY UTILITIES COMPANY

Group 1 ECR Rollin Calculations

Using Regenerated Revenues for the Twelve Months Ending September 30, 2015

Case No. 2015-00221

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Rate Class	12-Month Lighting Installations	12-Month Energy	kW per Light	Energy Rate -- ECR	Lighting Rate -- ECR	Base Fuel Revenue	ECR Energy Revenue	ECR Lighting Revenue	Total 12-Month ECR Revenue
								(3) x (5)	(2) x (6)	(8) + (9)
300	HPS Dark Sky Lantern, 4000 Lumen, Decorative Smooth Pole	-	1	0.060		$ 0.33	$ -	$ -	$ -	$ -
301	HPS Dark Sky Lantern, 9500 Lumen, Decorative Smooth Pole	-	-	0.117		$ 0.34	$ -	$ -	$ -	$ -
	Sheet No. 35.2									
360	Granville, 16000 Lumen, Fixture with Pole	2,352	277,075	0.181		$ 2.41	$ 7,513.10	$ -	$ 5,668.32	$ 5,668.32
	Granville Accessories:									
	Twin Crossarm Bracket (includes 1 fixture)	174								
	24 Inch Banner Arm	144								
	24 Inch Clamp Banner Arm	612								
	18 Inch Banner Arm	600								
	18 Inch Clamp Banner Arm	-								
	Flagpole Holder	204								
	Post-Mounted Receptacle	330								
	Additional Post-Mounted Receptacle (Limit 1 Per Pole)	-								
	Planter	330								
	Clamp-On Planter	-								
490	MH Contemporary, 12000 Lumen, Fixture Ony	707	35,351	0.150		$ 0.66	$ 1,392.79	$ -	$ 466.62	$ 466.62
494	MH Contemporary, 12000 Lumen, Decorative Smooth Pole	2,172	108,689	0.150		$ 0.66	$ 4,278.84	$ -	$ 1,433.52	$ 1,433.52
491	MH Contemporary, 32000 Lumen, Fixture Ony	3,828	442,763	0.350		$ 0.84	$ 16,422.12	$ -	$ 3,215.52	$ 3,215.52
495	MH Contemporary, 32000 Lumen, Decorative Smooth Pole	8,086	944,054	0.350		$ 0.84	$ 34,688.94	$ -	$ 6,792.24	$ 6,792.24
493	MH Contemporary, 107800 Lumen, Fixture Ony	520	187,969	1.080		$ 1.70	$ 5,413.20	$ -	$ 884.00	$ 884.00
496	MH Contemporary, 107800 Lumen, Decorative Smooth Pole	1,805	651,597	1.080		$ 1.70	$ 18,790.05	$ -	$ 3,068.50	$ 3,068.50
	Sheet No. 36									
461	HPS Cobra Head, 4000 Lumen, Fixture Only	82,982	1,664,928	0.060		$ 0.33	$ 47,299.74	$ -	$ 27,384.06	$ 27,384.06
471	HPS Cobra Head, 4000 Lumen, Fixture and Pole	43,697	878,314	0.060		$ 0.33	$ 24,907.29	$ -	$ 14,420.01	$ 14,420.01
409	HPS Cobra Head, 50000 Lumen, Fixture Only	1,664	261,622	0.471		$ 0.79	$ 7,537.92	$ -	$ 1,314.56	$ 1,314.56
426	HPS Open Bottom, 5800 Lumen, Fixture Only	1,963	53,864	0.083		$ 0.43	$ 1,570.40	$ -	$ 844.09	$ 844.09
454	MH Directional, 12000 Lumen, Fixture and Pole	1,739	86,950	0.150		$ 0.66	$ 3,425.83	$ -	$ 1,147.74	$ 1,147.74
455	MH Directional, 32000 Lumen, Fixture and Pole	12,328	1,438,582	0.350		$ 0.84	$ 52,887.12	$ -	$ 10,355.52	$ 10,355.52
459	MH Directional, 107800 Lumen, Fixture and Pole	2,442	880,423	1.080		$ 1.70	$ 25,421.22	$ -	$ 4,151.40	$ 4,151.40
446	MV Cobra Head, 7000 Lumen, Fixture Only	12,558	870,969	0.207		$ 0.39	$ 24,990.42	$ -	$ 4,897.62	$ 4,897.62
456	MV Cobra Head, 7000 Lumen, Fixture and Pole	1,658	114,545	0.207		$ 0.39	$ 3,299.42	$ -	$ 646.62	$ 646.62
447	MV Cobra Head, 10000 Lumen, Fixture Only	8,414	828,464	0.294		$ 0.44	$ 23,895.76	$ -	$ 3,702.16	$ 3,702.16
457	MV Cobra Head, 10000 Lumen, Fixture and Pole	5,368	528,611	0.294		$ 0.44	$ 15,245.12	$ -	$ 2,361.92	$ 2,361.92
448	MV Cobra Head, 20000 Lumen, Fixture Only	17,593	2,663,211	0.453		$ 0.51	$ 76,881.41	$ -	$ 8,972.43	$ 8,972.43
458	MV Cobra Head, 20000 Lumen, Fixture and Pole	17,160	2,596,943	0.453		$ 0.51	$ 74,989.20	$ -	$ 8,751.60	$ 8,751.60
404	MV Open Bottom, 7000 Lumen, Fixture Only	81,191	5,581,249	0.207		$ 0.39	$ 161,570.09	$ -	$ 31,664.49	$ 31,664.49
421	Incandescent Tear Drop, 1000 Lumen, Fixture Only	57	1,904	0.102		$ 0.12	$ 56.43	$ -	$ 6.84	$ 6.84
422	Incandescent Tear Drop, 2500 Lumen, Fixture Only	7,476	501,373	0.201		$ 0.16	$ 14,503.44	$ -	$ 1,196.16	$ 1,196.16
424	Incandescent Tear Drop, 4000 Lumen, Fixture Only	367	40,007	0.327		$ 0.24	$ 256.90	$ -	$ 88.08	$ 88.08
434	Incandescent Tear Drop, 4000 Lumen, Fixture and Pole	-	-	0.327		$ 0.24	$ -	$ -	$ -	$ -
425	Incandescent Tear Drop, 6000 Lumen, Fixture Only	24	3,572	0.447		$ 0.33	$ 103.20	$ -	$ 7.92	$ 7.92

KENTUCKY UTILITIES COMPANY

Group 1 ECR Rollin Calculations

Using Regenerated Revenues for the Twelve Months Ending September 30, 2015

Case No. 2015-00221

	(1)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
	Rate Class	Total 12-Month Revenue	Total Revenue Excluding ECR	ECR Revenue to Roll-in	Proposed ECR Component of Rates -- Energy	ECR Component of Monthly Per Light Rates	Proposed Base ECR Revenue	Difference Between Allocated ECR and Revised Revenue	Revised Rates	Existing Rates	Percent Change
			(11) - (10)	See Summary	(13) ÷ (3)	(13) ÷ (2)	(14) x (3) or (15) x (2)	(13) - (16)			
300	HPS Dark Sky Lantern, 4000 Lumen, Decorative Smooth Pole	$ -	$ -	$ -		$ 0.70	$ -	$ -	$ 24.72	$ 24.35	1.52%
301	HPS Dark Sky Lantern, 9500 Lumen, Decorative Smooth Pole	$ -	$ -	$ -		$ 0.72	$ -	$ -	$ 25.83	$ 25.45	1.49%
	Sheet No. 35.2										
360	Granville, 16000 Lumen, Fixture with Pole	$ 130,182.27	$ 124,513.95	$ 11,300.83		$ 4.80	$ 11,289.60	$ 11.23	$ 62.30	$ 59.91	3.99%
	Granville Accessories:										
	Twin Crossarm Bracket (includes 1 fixture)	$ 3,579.18	$ 3,579.18						$ 20.57	$ 20.57	0.00%
	24 Inch Banner Arm	$ 462.24	$ 462.24						$ 3.21	$ 3.21	0.00%
	24 Inch Clamp Banner Arm	$ 2,711.16	$ 2,711.16						$ 4.43	$ 4.43	0.00%
	18 Inch Banner Arm	$ 1,770.00	$ 1,770.00						$ 2.95	$ 2.95	0.00%
	18 Inch Clamp Banner Arm	$ -	$ -						$ 3.66	$ 3.66	0.00%
	Flagpole Holder	$ 277.44	$ 277.44						$ 1.36	$ 1.36	0.00%
	Post-Mounted Receptacle	$ 6,332.70	$ 6,332.70						$ 19.19	$ 19.19	0.00%
	Additional Post-Mounted Receptacle (Limit 1 Per Pole)	$ -	$ -						$ 2.62	$ 2.62	0.00%
	Planter	$ 1,468.50	$ 1,468.50						$ 4.45	$ 4.45	0.00%
	Clamp-On Planter	$ -	$ -						$ 4.94	$ 4.94	0.00%
490	MH Contemporary, 12000 Lumen, Fixture Ony	$ 11,101.16	$ 10,634.54	$ 851.64		$ 1.36	$ 961.52	$ (109.88)	$ 17.45	$ 16.75	4.18%
494	MH Contemporary, 12000 Lumen, Decorative Smooth Pole	$ 62,536.52	$ 61,103.00	$ 4,893.27		$ 1.36	$ 2,953.92	$ 1,939.35	$ 31.42	$ 30.72	2.28%
491	MH Contemporary, 32000 Lumen, Fixture Ony	$ 84,312.23	$ 81,096.71	$ 6,494.41		$ 1.77	$ 6,775.56	$ (281.15)	$ 24.68	$ 23.75	3.92%
495	MH Contemporary, 32000 Lumen, Decorative Smooth Pole	$ 285,919.54	$ 279,127.30	$ 22,353.16		$ 1.77	$ 14,312.22	$ 8,040.94	$ 38.64	$ 37.71	2.47%
493	MH Contemporary, 107800 Lumen, Fixture Ony	$ 24,134.32	$ 23,250.32	$ 1,861.94		$ 3.54	$ 1,840.80	$ 21.14	$ 51.32	$ 49.48	3.72%
496	MH Contemporary, 107800 Lumen, Decorative Smooth Pole	$ 107,378.12	$ 104,309.62	$ 8,353.36		$ 3.54	$ 6,389.70	$ 1,963.66	$ 65.28	$ 63.44	2.90%
	Sheet No. 36										
461	HPS Cobra Head, 4000 Lumen, Fixture Only	$ 636,573.64	$ 609,189.58	$ 48,785.31		$ 0.70	$ 58,087.40	$ (9,302.09)	$ 8.53	$ 8.16	4.53%
471	HPS Cobra Head, 4000 Lumen, Fixture and Pole	$ 463,886.53	$ 449,466.52	$ 35,994.32		$ 0.70	$ 30,587.90	$ 5,406.42	$ 11.73	$ 11.36	3.26%
409	HPS Cobra Head, 50000 Lumen, Fixture Only	$ 19,728.25	$ 18,413.69	$ 1,474.61		$ 1.67	$ 2,778.88	$ (1,304.27)	$ 13.56	$ 12.68	6.94%
426	HPS Open Bottom, 5800 Lumen, Fixture Only	$ 14,682.20	$ 13,838.11	$ 1,108.19		$ 0.91	$ 1,786.33	$ (678.14)	$ 8.54	$ 8.06	5.96%
454	MH Directional, 12000 Lumen, Fixture and Pole	$ 32,985.44	$ 31,837.70	$ 2,549.64		$ 1.36	$ 2,365.04	$ 184.60	$ 20.89	$ 20.19	3.47%
455	MH Directional, 32000 Lumen, Fixture and Pole	$ 307,446.92	$ 297,091.40	$ 23,791.77		$ 1.77	$ 21,820.56	$ 1,971.21	$ 27.56	$ 26.63	3.49%
459	MH Directional, 107800 Lumen, Fixture and Pole	$ 116,255.73	$ 112,104.33	$ 8,977.57		$ 3.54	$ 8,644.68	$ 332.89	$ 52.45	$ 50.61	3.64%
446	MV Cobra Head, 7000 Lumen, Fixture Only	$ 121,889.98	$ 116,992.36	$ 9,369.02		$ 0.81	$ 10,171.98	$ (802.96)	$ 10.77	$ 10.35	4.06%
456	MV Cobra Head, 7000 Lumen, Fixture and Pole	$ 19,983.32	$ 19,336.70	$ 1,548.53		$ 0.81	$ 1,342.98	$ 205.55	$ 13.27	$ 12.85	3.27%
447	MV Cobra Head, 10000 Lumen, Fixture Only	$ 96,270.55	$ 92,568.39	$ 7,413.09		$ 0.95	$ 7,993.30	$ (580.21)	$ 12.77	$ 12.26	4.16%
457	MV Cobra Head, 10000 Lumen, Fixture and Pole	$ 72,535.96	$ 70,174.04	$ 5,619.70		$ 0.95	$ 5,099.60	$ 520.10	$ 14.98	$ 14.47	3.52%
448	MV Cobra Head, 20000 Lumen, Fixture Only	$ 228,467.44	$ 219,495.01	$ 17,577.67		$ 1.09	$ 19,176.37	$ (1,598.70)	$ 14.45	$ 13.87	4.18%
458	MV Cobra Head, 20000 Lumen, Fixture and Pole	$ 261,712.12	$ 252,960.52	$ 20,257.67		$ 1.09	$ 18,704.40	$ 1,553.27	$ 16.91	$ 16.33	3.55%
404	MV Open Bottom, 7000 Lumen, Fixture Only	$ 866,205.37	$ 834,540.88	$ 66,831.97		$ 0.81	$ 65,764.71	$ 1,067.26	$ 11.87	$ 11.45	3.67%
421	Incandescent Tear Drop, 1000 Lumen, Fixture Only	$ 189.22	$ 182.38	$ 14.61		$ 0.26	$ 14.82	$ (0.21)	$ 3.81	$ 3.67	3.81%
422	Incandescent Tear Drop, 2500 Lumen, Fixture Only	$ 34,227.27	$ 33,031.11	$ 2,645.21		$ 0.35	$ 2,616.60	$ 28.61	$ 5.11	$ 4.92	3.86%
424	Incandescent Tear Drop, 4000 Lumen, Fixture Only	$ 2,503.52	$ 2,415.44	$ 193.43		$ 0.53	$ 194.51	$ (1.08)	$ 7.63	$ 7.34	3.95%
434	Incandescent Tear Drop, 4000 Lumen, Fixture and Pole	$ -	$ -	$ -		$ 0.53	$ -	$ -	$ 8.67	$ 8.38	3.46%
425	Incandescent Tear Drop, 6000 Lumen, Fixture Only	$ 220.83	$ 212.91	$ 17.05		$ 0.71	$ 17.04	$ 0.01	$ 10.19	$ 9.81	3.87%

KENTUCKY UTILITIES COMPANY

Group 1 ECR Rollin Calculations

Using Regenerated Revenues for the Twelve Months Ending September 30, 2015

Case No. 2015-00221

	(1) Rate Class	(2) 12-Month Lighting Installations	(3) 12-Month Energy	(4) kW per Light	(5) Energy Rate -- ECR	(6) Lighting Rate -- ECR	(7) Base Fuel Revenue	(8) ECR Energy Revenue	(9) ECR Lighting Revenue	(10) Total 12-Month ECR Revenue
								(3) x (5)	(2) x (6)	(8) + (9)
	Sheet No. 36.1									
460	MH Directional, 12000 Lumen, Decorative Smooth Pole	276	13,815	0.150		$ 0.66	$ 543.72	$ -	$ 182.16	$ 182.16
469	MH Directional, 32000 Lumen, Decorative Smooth Pole	3,253	379,073	0.350		$ 0.84	$ 13,955.37	$ -	$ 2,732.52	$ 2,732.52
470	MH Directional, 107800 Lumen, Decorative Smooth Pole	718	257,584	1.080		$ 1.70	$ 7,474.38	$ -	$ 1,220.60	$ 1,220.60
440	HPS Acorn, 4000 Lumen, Decorative Smooth Pole	25	484	0.060		$ 0.33	$ 14.25	$ -	$ 8.25	$ 8.25
410	HPS Acorn, 4000 Lumen, Historic Fluted Pole	2,880	57,616	0.060		$ 0.33	$ 1,641.60	$ -	$ 950.40	$ 950.40
466	HPS Colonial, 4000 Lumen, Decorative Smooth Pole	10,321	206,567	0.060		$ 0.33	$ 5,882.97	$ -	$ 3,405.93	$ 3,405.93
412	HPS Coach, 5800 Lumen, Decorative Smooth Pole	343	9,541	0.083		$ 0.43	$ 274.40	$ -	$ 147.49	$ 147.49
413	HPS Coach, 9500 Lumen, Decorative Smooth Pole	1,168	45,652	0.117		$ 0.34	$ 1,319.84	$ -	$ 397.12	$ 397.12
	Totals		6,555,515,152							$ 21,203,471

KENTUCKY UTILITIES COMPANY

Group 1 ECR Rollin Calculations
Using Regenerated Revenues for the Twelve Months Ending September 30, 2015
Case No. 2015-00221

	(1) Rate Class	(11) Total 12-Month Revenue	(12) Total Revenue Excluding ECR	(13) ECR Revenue to Roll-in	(14) Proposed ECR Component of Rates -- Energy	(15) ECR Component of Monthly Per Light Rates	(16) Proposed Base ECR Revenue	(17) Difference Between Allocated ECR and Revised Revenue	(18) Revised Rates	(19) Existing Rates	(20) Percent Change
			(11) - (10)	See Summary	(13) ÷ (3)	(13) ÷ (2)	(14) x (3) or (15) x (2)	(13) - (16)			
	Sheet No. 36.1										
460	MH Directional, 12000 Lumen, Decorative Smooth Pole	$ 7,600.83	$ 7,418.67	$ 594.10		$ 1.36	$ 375.36	$ 218.74	$ 30.10	$ 29.40	2.38%
469	MH Directional, 32000 Lumen, Decorative Smooth Pole	$ 110,151.59	$ 107,419.07	$ 8,602.37		$ 1.77	$ 5,757.81	$ 2,844.56	$ 36.77	$ 35.84	2.59%
470	MH Directional, 107800 Lumen, Decorative Smooth Pole	$ 40,076.21	$ 38,855.61	$ 3,111.65		$ 3.54	$ 2,541.72	$ 569.93	$ 61.66	$ 59.82	3.08%
440	HPS Acorn, 4000 Lumen, Decorative Smooth Pole	$ 332.80	$ 324.55	$ 25.99		$ 0.70	$ 17.50	$ 8.49	$ 15.11	$ 14.74	2.51%
410	HPS Acorn, 4000 Lumen, Historic Fluted Pole	$ 59,269.42	$ 58,319.02	$ 4,670.32		$ 0.70	$ 2,016.00	$ 2,654.32	$ 22.31	$ 21.94	1.69%
466	HPS Colonial, 4000 Lumen, Decorative Smooth Pole	$ 100,850.34	$ 97,444.41	$ 7,803.57		$ 0.70	$ 7,224.70	$ 578.87	$ 10.79	$ 10.42	3.55%
412	HPS Coach, 5800 Lumen, Decorative Smooth Pole	$ 10,757.80	$ 10,610.31	$ 849.70		$ 0.91	$ 312.13	$ 537.57	$ 33.87	$ 33.39	1.44%
413	HPS Coach, 9500 Lumen, Decorative Smooth Pole	$ 37,070.53	$ 36,673.41	$ 2,936.89		$ 0.72	$ 840.96	$ 2,095.93	$ 34.19	$ 33.81	1.12%
	Totals	$ 588,245,772	$ 567,042,301	$ 45,410,063			$ 45,406,420	$ 3,643			

The attachments are being provided in separate files in Excel format.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 99

Responding Witness: William S. Seelye

Q-99. Refer to the Seelye Testimony, Exhibit WSS-3. Explain what is meant by "Non-Burdened" and "Burdened" non-fuel operation and maintenance expenses, and how the amounts were calculated.

A-99. "Non-Burdened Expenses" are expenses without employee benefits and other allocated charges. "Burdened Expenses" correspond to employee benefits and allocated charges such as engineering overheads and administrative costs. The figures were calculated from the Company's financial forecast for the test year.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 100

Responding Witness: William S. Seelye

Q-100. Refer to the Seelye Testimony, Exhibits WSS-4 and WSS-5.

a. Explain how the "Fixed Charges ($/yr)" of 16.27 percent was calculated.

b. Explain why the "Distribution Energy per kWh ($/yr)" is equal to the Lighting Energy Service ("LE") tariff rate. Include in the response how the LE rate was calculated.

c. Explain how the "Operation and Maintenance ($/yr)" amount was calculated.

A-100.

a. The "Fixed Charges ($/yr)" of 16.27 percent represents the carrying charges for street lighting plant. The carrying charges include depreciation expenses, return on capital using the Company's overall weighted cost of capital, operation and maintenance expenses, income taxes and property taxes.

b. The Lighting Energy Service rate is applicable to customers that own their own street or security lighting equipment but purchase power and energy from the Company to operate the lights. The cost of supplying power and energy to customer-owned lights, which includes production demand and energy costs, transmission demand costs, and distribution demand costs, is the same on a per kWh basis as the cost of supplying demand and energy to utility-owned lights. In the Company's cost of service study, production demand and energy costs, transmission demand costs, and distribution demand costs are allocated to Lighting Energy Service (LES) in the same manner as Lighting Service (LS) and Restricted Lighting Service (RLS). Therefore, the underlying cost per kWh for delivered power and energy would be the same.

c. Operation and maintenance expenses for non-LED lights are calculated based on the cost of a bulb, photo-cell, and two hours of labor expected to occur every six years. For LEDs, the operation and maintenance expenses include the cost of a replacement fixture (light emitting diodes, ballast, and housing), photo-cell, and two hours of labor expected to occur every thirteen years.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 101

Responding Witness: William S. Seelye

Q-101. Refer to the Seelye Testimony, Exhibit WSS-8. Provide the basis for the space usage factor of .50.

A-101. The Federal Communication Commission ("FCC") calculation for underground conduit attachment rates assumes a space usage factor of 0.50. This assumes that an attachment of a cable or telecom provider into a particular underground conduit duct owned by the Company would accommodate 50% of the available space in that duct for conduit or conductor to be installed.

This assumption is addressed in further detail in sections 92-95 of the FCC Order supplied as a response to Question No. 92.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 102

Responding Witness: William S. Seelye

Q-102. Refer to the Seelye Testimony, Exhibit WSS-13, page 4 of 4. Explain how the split of Primary 65.21 percent and Secondary 34.79 percent was determined.

A-102. The Company's distribution engineering department performed an analysis classifying each size and category of overhead conductor and cable as primary and secondary. The cost of each size and category of overhead conductor and cable from the Company's Continuing Property Records (CPR) was then allocated based on the analysis performed by the distribution engineering department.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 103

Responding Witness: William S. Seelye

Q-103. Refer to the Seelye Testimony, Exhibit WSS-14, page 4 of 4. Explain how the split of Primary 91.81 percent and Secondary 8.19 percent was determined.

A-103. The Company's distribution engineering department performed an analysis classifying each size and category of underground conductor and cable as primary and secondary. The cost of each size and category of underground conductor and cable from the Company's Continuing Property Records (CPR) was then allocated based on the analysis performed by the distribution engineering department.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 104

Responding Witness: William S. Seelye

Q-104. Refer to the Seelye Testimony, Exhibits WSS-16 and WSS-17. Confirm that these two exhibits are the same, as there is no difference in the Functional Allocation and Classification under the BIP COSS and LOLP COSS. If this cannot be confirmed, identify the differences.

A-104. Confirmed.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 105

Responding Witness: William S. Seelye

Q-105. Refer to the Seelye Testimony, Exhibits WSS-18 and WSS-19, pages 37-38 of 38 for each exhibit. Explain the difference in the Interruptible Credit Allocator between the BIP COSS and LOLP COSS.

A-105. The difference in the Interruptible Credit Allocator between the BIP and LOLP methodologies was based on the inherent differences in how each of those methodologies allocated Production Demand costs. The Interruptible Service credit was allocated based on how Production Demand costs were allocated to each of the rate classes. The allocator used to allocate those costs was the BIP and LOLP, respectively, in each of the versions of the Cost of Service filed by the Company.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 106

Responding Witness: Christopher M. Garrett

Q-106. Refer to the Garrett Testimony, page 30, the journal entry at the bottom of the page.

a. State the date in 2019 the journal entry is expected to be made.

b. Confirm that the journal entry represents projected balances at full deployment of the AMS. If this cannot be confirmed, explain.

A-106.

a. The journal entry provided in the testimony is a summary of multiple journal entries that KU projects it will make if the AMS project is approved. For example, as KU replaces existing legacy meters starting in 2017, KU will debit Account 108, Accumulated depreciation and credit Account 101, Electric plant in service on a monthly basis. When the AMS program is completed in December 2019, KU will debit Account 182.2, Unrecovered plant and regulatory study costs and credit Account 108, Accumulated depreciation. This process will ensure that the legacy meters continue to be depreciated while in use which will serve to reduce the regulatory asset balance.

b. Confirmed.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 107

Responding Witness: Christopher M. Garrett

Q-107. Refer to the Garrett Testimony, pages 31-32. Beginning at the bottom of page 31, Mr. Garrett discusses KU's request for amortization of a regulatory liability related to reservation or termination fees received by KU for refined coal production facilities at certain generating stations. The testimony also references Case No. 2015-00264.[6] The final Order in that proceeding states that KU and LG&E could receive up to $19.6 million of site licensing and coal yard services fees, and that the terms of the agreements were expected to run to the fourth quarter of 2021 unless the tax credit was extended. State the amount of fees related to the refined coal production facilities that are included as revenue in KU's test year.

A-107. KU has included $287,281 of regulatory liability amortization in the test year. This was based on an estimated $861,843 in jurisdictional reservation and termination fees as of December 31, 2016 and a proposed 3 year amortization period. Actual jurisdictional fees recorded to the regulatory liability at December 31, 2016 were $558,325.

Due to the absence of active investor interest in refined coal projects and the terminable-at-will nature of the Exclusivity and Fees Agreement with Tinuum (formerly Clean Coal Solutions), the 2017 KU business plan assumed that no refined coal revenues would be received. (Tinuum has the ability to terminate the existing Exclusivity and Fees Agreement upon 30 days' notice, quarterly, and had not indicated success locating a tax equity investor when the business plan was being developed.) However, in late 2016 Tinuum found a potential investor for the Ghent refined coal facility. The facility is under construction and KU is negotiating the necessary agreements with the investor. Subject to successful construction and completion of negotiations, the Ghent facility may be operational and under contract for its primary term in the second quarter of 2017. For ratemaking purposes, KU proposes to true-up the regulatory liability amortization utilized in this proceeding based on the actual fees received as of the end of the base period, February 28, 2017. Furthermore, KU proposes to continue

[6] Case No. 2015-00264, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling* (Ky. PSC Nov. 24, 2015).

to record fees received after the base period to the regulatory liability and will amortize those fees in a future rate proceeding.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 108

Responding Witness: Valerie L. Scott

Q-108. Refer to KU's response to Commission Staff's Initial Request for Information ("Staff's First Request"), Item 27.

a. The Rate Schedules listed on this page include "Street Lighting" and "Private Outdoor Lighting" but do not include "Lighting Service" and "Restricted Lighting Service" as set forth in KU's tariff. Reconcile the two lighting classes listed in the response to the two lighting schedules included in KU's tariff.

b. Identify the Kentucky jurisdictional special contract customer shown on this page for 2015 and the base period.

A-108.

a. An amended schedule for KU's response to Commission Staff's Initial Request for Information ("Staff's First Request"), Item 27, which includes "Lighting Service" and "Restricted Lighting Service" rate schedules was filed January 20, 2017. In the filing, reporting classes have been updated to reflect the appropriate tariff rate schedule. The billed rate codes did not change and customers were correctly billed under the corresponding tariff.

b. American Municipal Power, Inc. is the special contract customer.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 109

Responding Witness: John P. Malloy

Q-109. Refer to the letter/request to intervene filed on December 6, 2016, by the Greater Muhlenberg Parks and Recreation System.

a. State whether the customer's account was transferred from the General Service tariff to the Power Service tariff in May 2015. If so, explain why the customer was transferred.

b. Provide the customer's usage and amount billed for each month of 2014, 2015, and 2016.

A-109.

a. The Muhlenberg Co. Board of Education (Greater Muhlenberg Parks and Recreation System) account was changed from the General Service tariff to the Power Service tariff in April 2016. The rate was changed due to the account's demand averaging more than 50 kW and Power Service is the only applicable rate available.

b. See attached.

Muhlenberg Co. Board of Education (Greater Muhlenberg Parks and Recreation System)
Customer usage and monthly bills for 2014, 2015, 2016

Rate Category/Tariff	Billing Period	Revenue Amount $	Total Energy KWH	Demand Billed KW	Demand Measured KW
GS Three Phase	2014/01	$ 21.50	0		
GS Three Phase	2014/02	$ 38.43	0		
GS Three Phase	2014/03	$ 35.97	0		
GS Three Phase	2014/04	$ 35.74	0		
GS Three Phase	2014/05	$ 36.33	0		
GS Three Phase	2014/06	$ 36.82	0		
GS Three Phase	2014/07	$ 899.02	8,480		146.6
GS Three Phase	2014/08	$ 449.35	4,200		154.8
GS Three Phase	2014/09	$ 519.03	4,880		154.8
GS Three Phase	2014/10	$ 477.64	4,440		154.8
GS Three Phase	2014/11	$ 1,435.15	14,160		155.8
GS Three Phase	2014/12	$ 1,068.95	10,640		155.8
	TOTAL - 2014	$ 5,053.93	46,800		922.6
GS Three Phase	2015/01	$ 37.81	0		155.8
GS Three Phase	2015/02	$ 37.37	0		
GS Three Phase	2015/03	$ 37.42	0		
GS Three Phase	2015/04	$ 41.35	40		
GS Three Phase	2015/05	$ 2,207.02	22,200		169.3
GS Three Phase	2015/06	$ 816.92	7,760		165.2
GS Three Phase	2015/07	$ 523.50	4,600		147.6
GS Three Phase	2015/08	$ 569.60	5,120		147.4
GS Three Phase	2015/09	$ 924.96	8,640		163.8
GS Three Phase	2015/10	$ 455.57	4,000		161.5
GS Three Phase	2015/11	$ 480.49	4,280		72.8
GS Three Phase	2015/12	$ 450.98	4,080		145.8
	TOTAL - 2015	$ 6,582.99	60,720		1329.2
GS Three Phase	2016/01	$ 501.08	4,520		76.0
GS Three Phase	2016/02	$ 479.81	4,080		8.1
GS Three Phase	2016/03	$ 649.01	5,480		152.9
PS Secondary	2016/04	$ 3,144.74	8,160	160.8	160.8
PS Secondary	2016/05	$ 3,563.30	8,960	161.2	161.2
PS Secondary	2016/06	$ 3,540.08	9,160	157.8	157.8
PS Secondary	2016/07	$ 3,453.75	6,480	158.1	158.1
PS Secondary	2016/08	$ 1,860.02	4,600	81.9	37.4
PS Secondary	2016/09	$ 3,574.99	9,320	161.8	161.8
PS Secondary	2016/10	$ 3,000.79	6,760	154.8	154.8
PS Secondary	2016/11	$ 1,598.82	3,280	80.9	64.1
PS Secondary	2016/12	$ 1,662.11	3,880	80.9	72.4
	TOTAL - 2016	$ 27,028.50	74,680	1198.2	1289.4

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 110

Responding Witness: John P. Malloy

Q-110. Refer to the comment letter filed on January 4, 2017, by Fredonia Food & More, the third paragraph. Provide a detailed explanation for the change in rate schedule discussed in this paragraph.

A-110. Customer was receiving service under Power Service ("PS") rate schedule prior to April 2015. Customer's measured 12-month average monthly maximum loads did not exceed 50 kW starting in the first quarter of 2014. In July 2014, a KU representative met with the customer to discuss measured demands and possible rate change. The account continued to be below the 50 kW minimum for Rate PS and in March 2015 a letter was sent to customer notifying of the rate change from Rate PS to General Service ("GS"). Customer contacted KU in April 2015 to discuss the rate change and at that time a Company representative explained the anticipated billing increase would be $400-$500 per month. No additional contact with customer about the rate change has occurred since April 2015.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Commission Staff's Second Request for Information
Dated January 11, 2017

Question No. 111

Responding Witness: John P. Malloy

Q-111. Refer to the Cadmus Industrial Sector DSM Potential Assessment for 2016-2035-Final Report ("CADMUS Study") filed by the Companies into the post-case file in Case No. 2014-00003.[7] Refer also to the KU/LG&E DSM Energy Efficiency 7 Case No. 2014-00003, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs (Ky. PSC Nov. 14, 2014). Advisory Group's October 14, 2016 report to the Commission filed into the post-case files in Case Nos. 2014-00371 and 2014-00372.[8]

a. Explain whether Kentucky Industrial Utility Customers, Inc. ("KIUC") has been invited to participate in the Companies' DSM Advisory Group, and if so, whether any KIUC member has attended any meetings of the DSM Advisory Group.

b. Based on the findings of the CADMUS Study, identify and describe any actions undertaken by KU regarding industrial DSM since the study's completion.

c. Based on the findings of the CADMUS Study, explain whether KU has any plans to include industrial programs in its DSM portfolio in the future.

d. Explain whether any of KU's customers that participated in the CADMUS Study have expressed interest in an industrial DSM program.

A-111.

a. Yes, KIUC has been invited to all DSM Advisory Group meetings and their counsel, representatives, and/or members have attended and participated in

[7] Case No. 2014-00003, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs (Ky. PSC Nov. 14, 2014).
[8] Case Nos. 2014-00371 , Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and 201 4-00372, Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates (Ky. PSC June 30, 2015).

all meetings.

b. The Company held meetings with the DSM Advisory Group on June 23, August 24, and October 13 of 2016 to discuss the results of the Cadmus report, what DSM programs might be of value to industrial customers, how other states deal with industrial opt out (presented by Midwest Energy Efficiency Alliance) and how to define criteria for industrial customer opt-out of the Companies' DSM programs. The advisory group generally agreed to a revised definition of electric industrial customer, criteria for determining if an industrial customer is energy intensive, and a method for recording that energy intensive industrial customers who wish to opt-out of utility programs confirm they are investing in cost-effective energy efficiency measures as contain in KRS 278.285. Meeting presentations and minutes are publicly available at https://lge-ku.com/dsm and are attached for ease of reference.

c. Historically, the Companies offered residential and commercial programs only. No industrial programs were offered. The Companies currently plan to move away from the historical classification and offer residential and non-residential programs. Industrial customers who do not or cannot exercise their statutory opt-out would have all of the non-residential programs available to them for participation. In compliance with Section 3.3 (B), page 9, of the settlement agreement approved by the Commission in Case Nos. 2014-00371 and 2014-00372, the Companies plan to address these issues in their next DSM application, which the Companies presently anticipate filing with the Commission no later than February 28, 2018.

d. No industrial customer has expressed an interest in participating in the Companies' DSM programs.

LG&E KU

PPL companies

Energy Efficiency Advisory Group – Stakeholder Meeting

June 23, 2016

Agenda

- Welcome / Intros
- Industrial Potential Study Results
  - *Achievable potential*
  - *Energy efficiency program examples*
- Industrial Exemption/DSM Opt-out
  - *State law KRS 278.285*
- Next Steps

PPL companies

PSC Order from DSM Application (CASE NO. 2014-000003)

5. Within three months of the issuance of this Order, the Companies shall commission an industrial potential or market-characterization study.

6. The Companies shall file with the Commission the industrial potential or market-characterization study within 30 days of the date it is completed and finalized.

Study was submitted to KY PSC on May 26, 2016.

LG&E KU
PPL companies

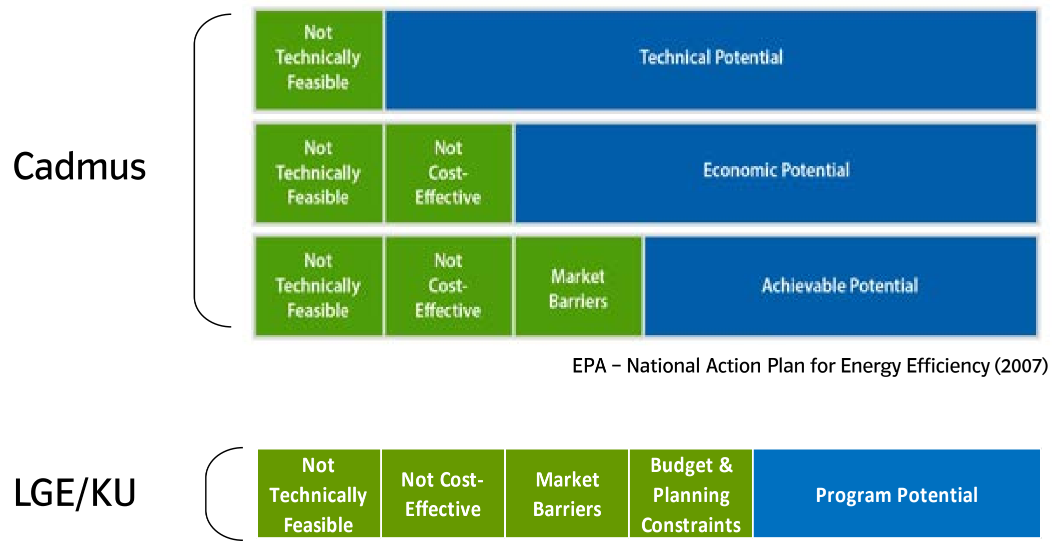
Per ARTICLE III., Section 3.3 Industrial DSM-EE Matters - Final PSC Order from CASE NOs. 2014-00371 and 2014-00372

(A) The Utilities commit to instruct the vendor for their industrial-DSM-EE potential study to commence work on the study immediately, and will not seek DSM cost recovery of the study's cost. The Utilities further commit that the study will be completed by May 1, 2016, and filed with the Commission thirty days later in accordance with the Commission's final order in Case No. 2014-00003. Thereafter, Utilities commit that they will commence the DSM Advisory Group meeting process to discuss the results of the industrial study.

(B) The Utilities commit to address opt-out criteria for industrial customers, as well as the definition of "industrial," including whether the NAICS code should be used to define "industrial," in their first DSM-EE application following completion of their industrial-DSMEE-potential study.

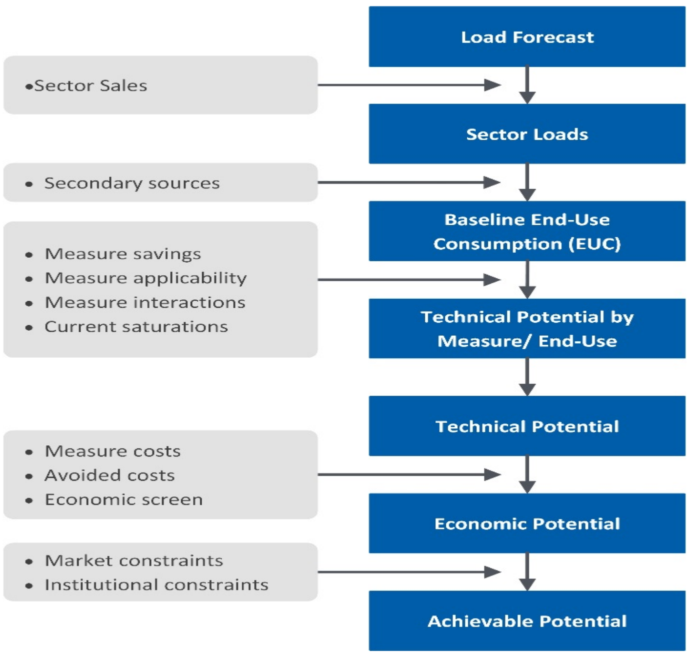
PPL companies

Types of Energy Efficiency Potential 2016-2035



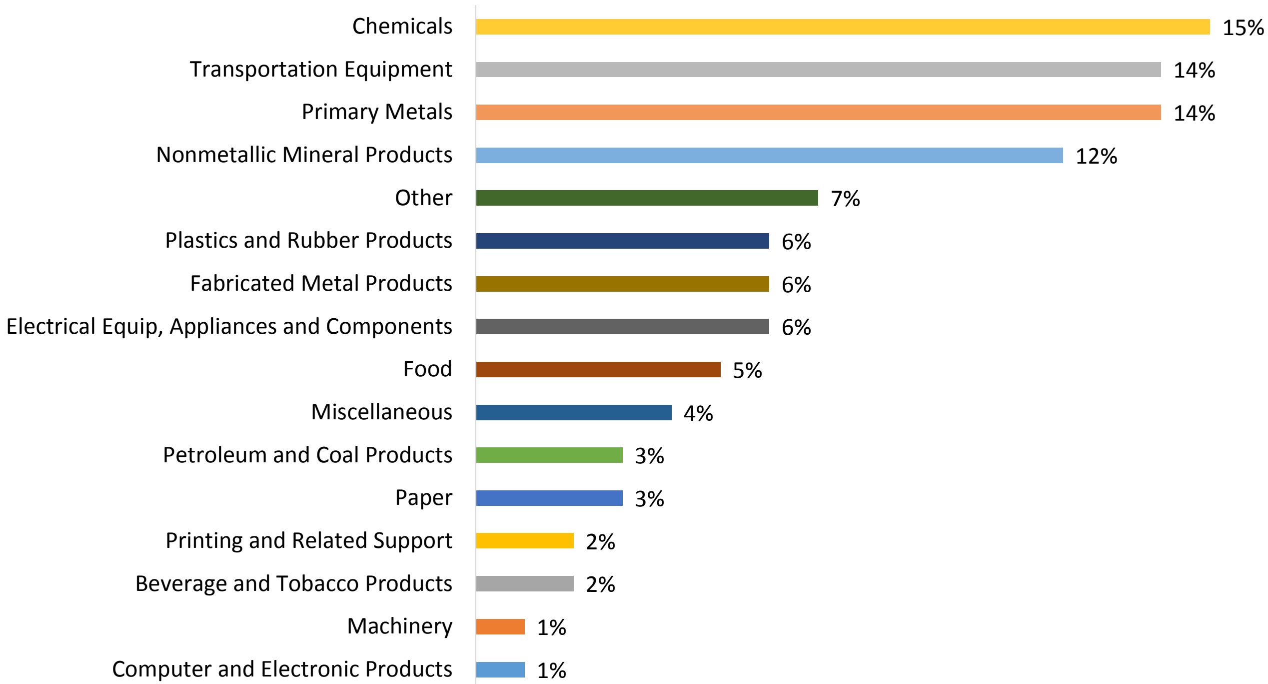
PPL companies

Potential Study Methodology



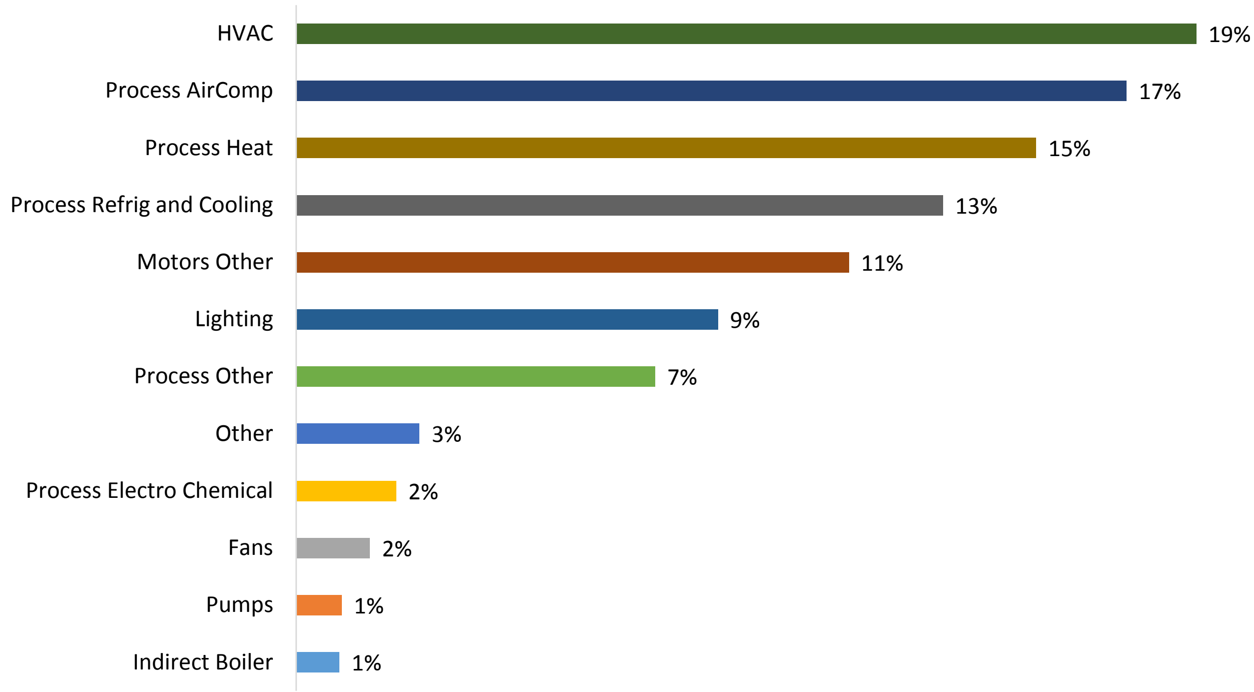
LG&E KU PPL companies

Electric Baseline Consumption by Industry - 2035



PPL companies

Electric Economic Potential by End Use – 20 yr. Cumulative



LG&E KU
PPL companies

Technical & Economic Energy Efficiency Potential

Energy

Utility	2035 Baseline Sales - MWh	20-Year Cumulative Potential - MWh		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
LGE	2,626,749	428,025	384,170	16.3%	14.6%	90%
KU	6,370,330	941,051	827,301	14.8%	13.0%	88%
Total	8,997,079	1,369,076	1,211,471	15.2%	13.5%	88%

Utility	20-Year Cumulative Potential - MW	
	Technical	Economic
LGE	53	48
KU	115	101
Total	168	149

LG&E KU
PPL companies

Achievable Energy Efficiency Potential

Utility	20-Year Cumulative Achievable Potential - MWh		
	Low	Medium	High
MWh—Cumulative 20-year			
LGE	126,776	192,085	257,394
KU	273,009	413,651	554,292
Total	**399,785**	**605,736**	**811,686**
Percent of Baseline			
LGE	4.8%	7.3%	9.8%
KU	4.3%	6.5%	8.7%
Total	**4.4%**	**6.7%**	**9.0%**

Demand

Utility	20-Year Cumulative Achievable Potential - MW		
	Low	Medium	High
LGE	16	24	32
KU	33	51	68
Total	**49**	**74**	**100**

LG&E KU PPL companies

New Program Possibilities...

- Industrial Rebates — Expanding to C&I
  - *Expands existing Commercial Rebates Program where Companies pay $100/kW for demand reductions that are result of prescriptive and custom measures*
- Industrial Energy Efficiency Consulting [redacted]
  - *New offering where Companies provide energy efficiency audit services for small to medium sized Industrial Customers*
- Industrial Automated Demand Response (ADR) — Expanding to C&I
  - *Expands existing Large Commercial ADR Program where Companies pay annual incentives ($25/kW) for controllable demand reductions*
- Industrial Strategic Energy Management (SEM) — New
  - *New offering where selected participants go on year-long in-depth EE awareness and facility education; No/low cost options are explored.*

Opt Out Current State Law: KRS 278.285

- (3) The commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The **commission shall allow individual industrial customers** with **energy intensive processes** to **implement cost-effective energy efficiency measures** in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

Next Steps

- DSM timeline
  - *Early 2018: estimated date for next DSM filing*
  - *Early 2017: decision on continued and new programs for 2019 forward*
  - *July 2016 – February 2017: series of Advisory Committee meetings to get firm understanding and consensus agreement of energy intensive definition and opt-out impacts*

- Input of meeting schedule and what gets accomplished

- Discussion items
  - *Energy intensive definition*
  - *Industrial programs*
  - *Costs and impacts*

LG&E KU
PPL companies

PPL companies

Thank you

MEETING RECORD
Energy Efficiency Advisory Group Meeting

Date:	**June 23, 2016**
Location:	**Fairfield Inn & Suites** 1220 Kentucky Mills Drive Louisville, KY 40299
Participants:	**LG&E /KU:** Eight employees from various departments, including Energy Efficiency, Regulatory Affairs and Customer Service. **Stakeholders:** Representatives from twelve stakeholder groups.
Date Issued:	06/27/2016
Issued by:	John Hayden

The following meeting minutes have been prepared to summarize the conversations and issues discussed at the above referenced meeting.

Welcome / Introductions

David Huff welcomed the meeting participants. He reiterated the purpose for the meeting to the group as well as provided an introduction to Greg Lawson, the new Manager of LG&E/KU's Energy Efficiency Planning & Development Department. Lastly, he detailed the expiration of current DSM programming in December 2018 and the upcoming timeline of the next DSM Filing in 2018 to the Kentucky PSC for commencement of new DSM programming in January 2019.

Meeting Agenda

Greg Lawson introduced himself to the group and also thanked meeting participants for attending. All meeting participants then introduced themselves and indicated their company, agency, or organization of affiliation. Greg provided an overview of the meeting agenda:

- Welcome / Intros
- Industrial Potential Study Results
- Industrial Exemption / DSM Opt-Out
- Next Steps

Industrial Potential Study Results

Greg Lawson began by providing some background information on the regulatory orders that requested the Potential Study be commissioned. He mentioned to the group that a web link to the Study was distributed to attendees prior to the meeting. The study is also available online on the Kentucky PSC website. He then provided a description of the types of Energy Efficiency Potential, the methodology utilized by the vendor (The Cadmus Group, Inc.) who performed the study, as well as an overview of the Study's results.

- Discussion ensued regarding the results as well as the impact it may have on future programming.

- Questions were presented to the group about the results and the methodology used. A sample of some of the questions were:

  - Q) Where did the research data come from?
    - A) Secondary research came from national sources including the Manufacturing Energy Consumption Survey, the IAC facility audit database (which includes the Kentucky Industrial Assessment Center data), as well as Energy Information Administration Form 861. Primary research resulted from surveying the industrial customers in the service territories.
  - Q) How does current industrial consumption translate to potential?
    - A) Consumption by industry does not equally translate proportionally to end-use potential.
  - Q) How did the vendor determine cost-effectiveness?
    - A) Each measure was evaluated using a Total Resources Cost test based on the Company's forecast of energy and capacity costs
  - Q) Did the customer survey response portion of the study derive from a statistically significant sample size?
    - A) Yes, the surveyor reached out to all industrial customers (either via by phone, email/online, and by printed letters) and the responses received were statistically significant.

Industrial Exemption / DSM Opt-Out

Greg Lawson continued by describing the work that is currently being done by the Planning & Development department to identify program possibilities. It was mentioned that this work is still ongoing as the study did not analyze program potential.

- The group was asked to assist LG&E/KU in the current and future meetings in identifying what might be missing from the presented list as well identifying what programs may not be needed.
- The study described various types of utility programs in other states.
- In response to a participant's question about how the utility would determine what programs to offer, it was replied that in addition to the standard analysis, planning, and cost / benefit tests, the utility would also rely on these meetings to help to determine what to offer.
- The current state law (KRS 278.285) was provided for all to see the current language regarding industrial opt-out. Discussion revolved at how best to define and interpret the language in the law.

Next Steps

- Some of the topics suggested by the participants for the next meeting are listed below:
  - How do other states define the issues? Could MEEA provide some context to group and/or present?
  - What are the options for defining energy intensive?
  - What are the program funding impacts?

- David Huff asked the group for their preference on the timing of the next meeting. He indicated that LG&E/KU needed at least a month to continue their analysis. **A follow-up meeting was suggested for August 2016**. In the interim, it was mentioned that the DSM Advisory Group could reach out with any questions, comments, or issues regarding programming.

- Greg Lawson closed the meeting with thanking participants for their attendance, continued support, and the robust discussion of the issues.

Industrial Opt-Out Policies in the Midwest

Nick Dreher, Policy Manager
Midwest Energy Efficiency Alliance

Energy Efficiency Advisory Group Meeting

August 24, 2016

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

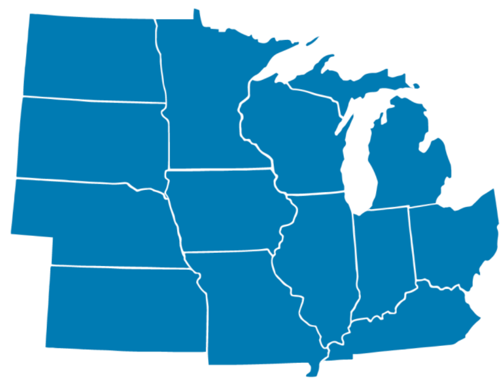
About MEEA

The Trusted Source on Energy Efficiency

We are a nonprofit membership organization with 160+ members, including:

- Utilities
- State and local governments
- Energy efficiency-related businesses
- Research institutions

As the key resource and champion for energy efficiency in the Midwest, MEEA helps a diverse range of stakeholders understand and implement cost-effective energy efficiency strategies that provide economic and environmental benefits.



MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

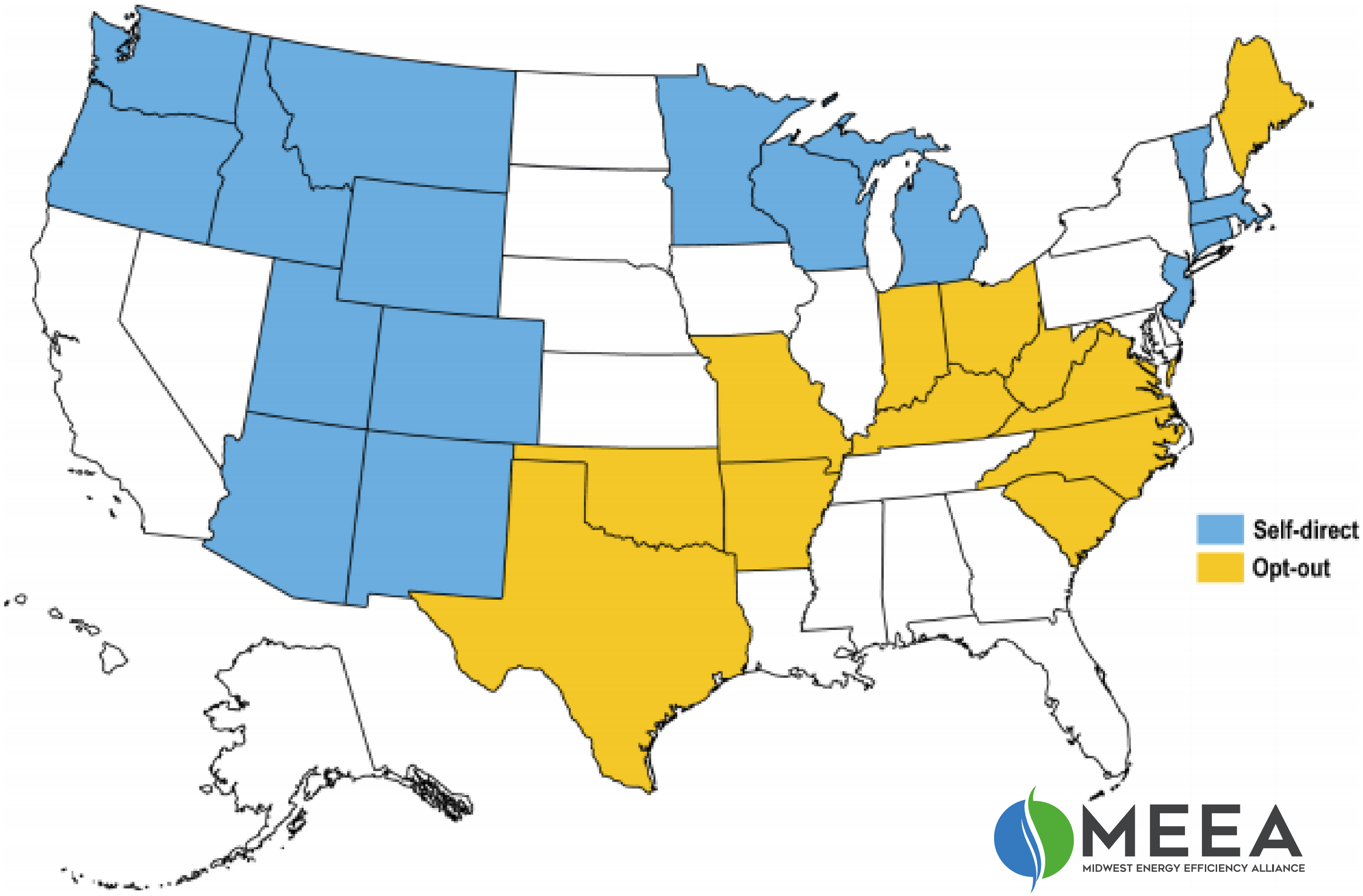
Opt-out and Self- Direct

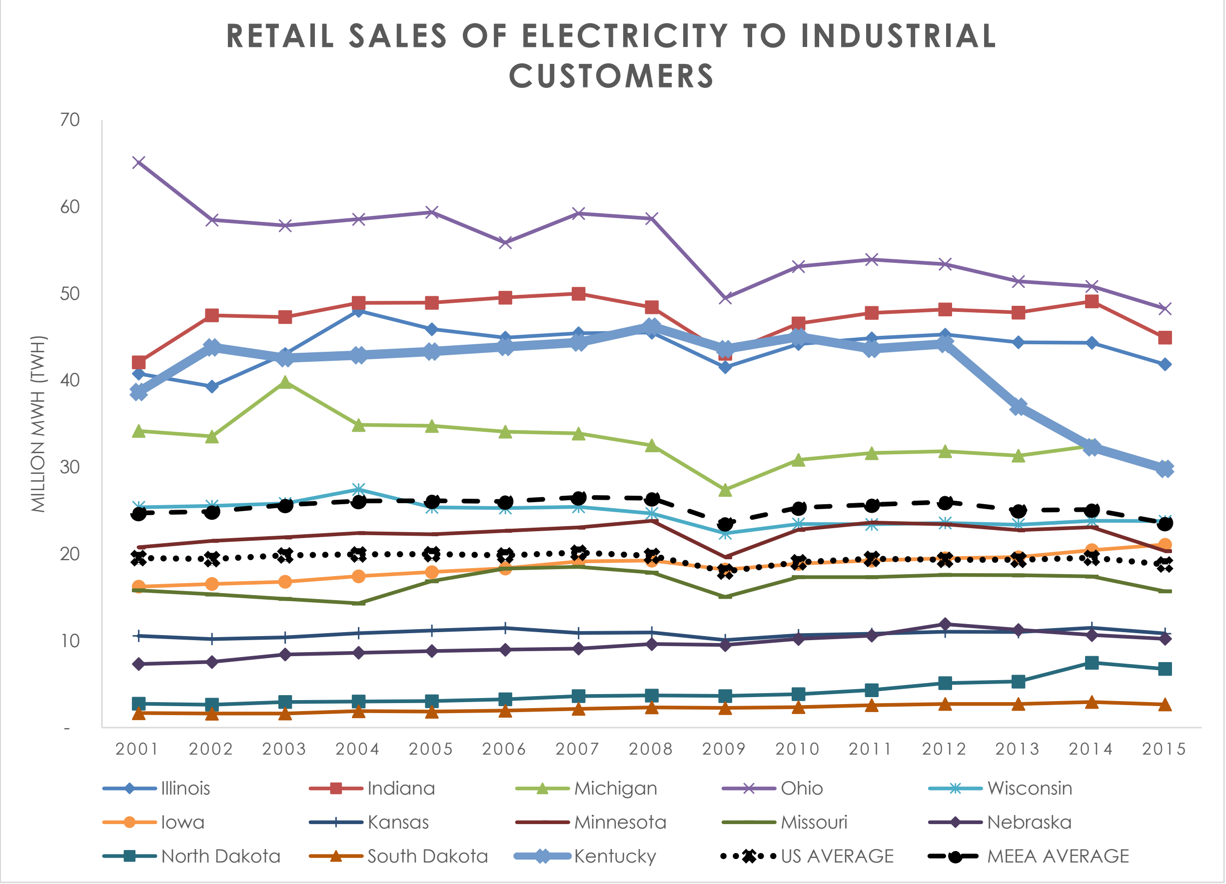
- Several Midwestern states have adopted **opt- out** policies that allow large energy users— with diverse criteria that vary state-to-state— to "opt-out" of paying into utility efficiency programs

- **Self-direct** programs allow large energy users to contribute to funding energy efficiency programming (either on their bills or through some other mechanism) and then direct those funds toward the design, implementation, and verification of energy-saving projects in their own facilities

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

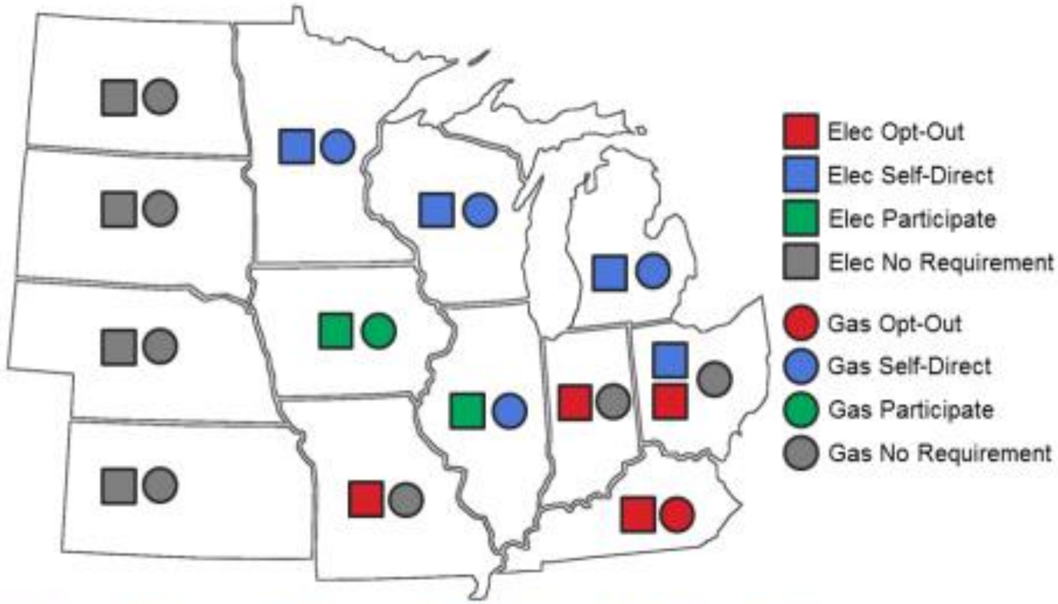
Overview of Large-Customer Self-Direct Options for Energy Efficiency Programs





MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Industrial Opt-Out and Self-Direct Policies



Industrial Energy Efficiency Self-Direct and Opt-Out Policies

Midwest Energy Efficiency Alliance, 2015

Illinois

- Customers eligible for gas self-direct under Public Act 96- 0033:
  - Have an annual usage in the aggregate of 4 million therms or more within the service territory of the affected gas utility **or** with aggregate usage of 8 million therms or more across Illinois
- Gas direct
  - NAICS code number 22111, 31-, 32-, 33-
  - There are 38 Self-Direct Customers with a collective annual natural gas usage of 780 million therms.
  - No reporting requirements
- No Electric Opt-out/Self-Direct

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Indiana

- "Industrial customer" defined in SB 340 as:
  - Single site constituting more than one megawatt (1 MW) of electric capacity from an electricity supplier
- Electric Opt-Out
  - Applies to five IOUs
  - No reporting requirement
  - About 70-80% of eligible load has opted out
- No natural gas savings requirement

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Michigan

- Customers eligible for electric self direct under 460.1093 must have:
  - In 2011- 2013, an annual peak demand in the preceding year of at least 1,000 kilowatts at each site or 5,000 kilowatts in the aggregate at all sites to be covered
  - In 2014 or later, an annual peak demand in the preceding year of at least 1,000 kilowatts in the aggregate at all sites to be covered by the self-directed plan
- Electric Self Direct Only
  - In 2009, 77 large customers self-directed
    - By 2014, dropped to 24

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Minnesota

- "Large customer facility" defined in Minn. Stat. 216B.241 as:
  - All buildings, structures, equipment, and installations at a single site that collectively
    - (1) impose a peak electrical demand on an electric utility's system of not less than 20,000 kilowatts **or**
    - (2) consume not less than 500 million cubic feet of natural gas annually
- Electric and Natural Gas Self-Direct
  - Customers must also show that they are making "reasonable" efforts to identify or implement energy efficiency and that they are subject to competitive pressures that make it helpful for them to be exempted from the CRM fees

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Missouri

- Customers eligible for opt-out in Missouri Energy Efficiency Investment Act (MEEIA):
  (1) Customer has demand of at least 5,000 kilowatts for the past 12 months
  (2) Customer operates an interstate pipeline pumping station, regardless of size
  (3) The customer has a demand of 2,500 kilowatts or more AND the customer has a "comprehensive" demand-side or energy efficiency program and can demonstrate an achievement of savings equivalent to utility programs.
- Opt- out
  – MEEIA allows customers to opt-out of all DSM programs' costs recovery if they meet any one of the above criteria
  – No reporting requirement
  – MPSC desk and field audits

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Ohio

- "Customer" defined in SB 310 as:
  - Any customer of an electric distribution utility to which either of the following applies:
    - The customer receives service above the primary voltage level as determined by the utility's tariff classification.
    - The customer is a commercial or industrial customer to which both of the following apply:
      - The customer receives electricity through a meter of an end user or through more than one meter at a single location in a quantity that exceeds 45 million kilowatt hours of electricity for the preceding year.
      - The customer has made a written request for registration as a self-assessing purchaser.
- Statewide Electric Opt-Out
  - If the specified reduction levels are met, the customer can request exemption from the cost recovery mechanism.
  - Send notice of intent to opt-out to the PUCO
  - Reporting Requirements
- AEP Electric Self-Direct
  - Offers customers an incentive for previously implemented energy efficiency measures.
  - The one-time incentive is 75% of what the measure would cost under AEP programs and has a maximum limit of $225,000.
  - Projects must have been implemented after Jan. 1, 2008 and must produce 100% of stated energy savings and/or peak demand reductions over a five-year period.

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Wisconsin

- "Large energy customer" defined in 2005 Wisconsin Act 141 as:
  - Having an energy demand of at least 1,000 kilowatts of electricity per month or at least 10,000 decatherms of natural gas per month **and**
  - that, in a month, is billed at least $60,000 for electric service, natural gas service, or both.
- Electric/Natural Gas Self-Direct
  - Industrial customer must deduct the amount of program funding from the amount they must contribute to Focus through their utility
  - Proposals for a customer to run such a program require an Measurement & Verification plan, must pass a cost-effectiveness screening, and set and measure performance goals

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Kentucky

- Pursuant to Kentucky Revised Statute 278.285
  - The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes
- Approximately 80% of eligible industrial load has opted out of investor-owned Utility DSM programs
- Duke Energy Self-Direct
  - Only for customers that take transmission service on rate TT
  - No measurement and verification for self-direct savings
- Tennessee Valley Authority
  - No reporting requirement

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

Thank you!

Nick Dreher
Midwest Energy Efficiency Alliance
ndreher@mwalliance.org

MEETING RECORD
Energy Efficiency Advisory Group Meeting

Date:	**August 24, 2016**
Location:	**Fairfield Inn & Suites** 1220 Kentucky Mills Drive Louisville, KY 40299
Participants:	**LG&E /KU:** Ten employees from various departments, including Energy Efficiency, Regulatory Affairs, and Customer Service **Stakeholders:** Representatives from ten stakeholder groups.
Date Issued:	08/30/2016
Issued by:	Kelli Higdon

The following meeting minutes have been prepared to summarize the conversations and issues discussed at the above referenced meeting.

Welcome / Introductions

Greg Lawson, the Manager of LG&E/KU's Energy Efficiency Planning & Development Department, welcomed the meeting participants. He reiterated the purpose for the meeting to the group. All meeting participants then introduced themselves and indicated their company, agency, or organization of affiliation.

Meeting Agenda

Greg Lawson thanked meeting participants for attending and provided an overview of the meeting agenda:

- Welcome / Intros
- Review of opt-out rules in other states - presentation from MEEA representative
- DSM Opt-Out in surrounding states not in MEEA
- Review of Kentucky state law and current tariff
- Energy intensive definition / Cost-effective energy efficiency measures
- Analysis of industrial exemption impact
- Next Steps

Industrial Exemption / DSM Opt-Out

Greg Lawson began by introducing Nick Dreher from MEEA, a nonprofit membership organization and advocate for energy efficiency. Nick presented slides for each of the states in their organization and details of how they defined an industrial customer and whether they had opt-out or self-direct policies. Greg Lawson then presented similar information for the surrounding states that are not in MEEA.

Next the Kentucky Revised Statute vs. current tariff language was discussed. Barry Naum, Walmart's attorney, noted that the statute does not specifically state NAICS codes in its definition of an industrial customer but the tariff language does. This led to further discussions on how an industrial customer should be defined.

Next, Greg Lawson stated that he would like for the focus of this meeting to be on the language "Energy Intensive", which could be based on the customer's prior 12 months "base" demand. A chart was presented that showed the impacts of different opt-out levels. It was noted that we currently have 100% opt-out for our industrial customers. Then it was asked why LG&E/KU were seeking to develop a program for industrial customers. The order from Case Nos. 2014-00371 and 2014-00372 states that we are to "commit to address opt-out criteria for industrial customers, as well as the definition of 'industrial', including whether the NAICS code should be used to define 'industrial'". David Huff stated that many industrial customers commented that they had people on staff to address their own energy efficiency projects / measures. David stated that we are required by the KPSC to report on the findings of the Potential Study before we can make a new DSM filing and we would like to file our new DSM filing no later than Feb 28, 2018.

Various stakeholders discussed their interpretation of the statute and how it relates to the existing tariff language.

Participants were directed to the Potential Study p.32 - Figure 12, showing the percentage of respondents with energy managers on site and also to p.49 - Figure 34, showing Electric Economic Potential by End Use.

David Huff said for the next meeting we would continue our analysis of the program and could back into the amount of program costs that would be spread across all industrial customers at each of these break-outs shown on slide 8 of Greg Lawson's presentation and look at the cost benefit ratios to report back to the group.

Next Steps

- Some of the topics suggested by the participants for the next meeting are listed below:
  - What is the definition of an industrial customer?
  - What is the definition of "energy intensive"? Is there a non-arbitrary threshold from which to base this on?
  - Discuss tariff language.

- Greg Lawson thanked the participants for their discussions at these meetings and reiterated that the meetings are open to all industrial customers if they want to participate. He then asked the group for their preference on the timing of the next meeting. He indicated that LG&E/KU needed at least a month to continue their analysis. **A follow-up meeting was suggested for late September or early October 2016**. In the interim, it was mentioned that the DSM Advisory Group could reach out with any questions, comments, or issues regarding programming.

- Rick Lovekamp stated that, as required, we provide the KPSC a monthly status update of any meetings that we have on this topic.

- Greg Lawson thanked the participants for their attendance and closed the meeting.

DSM Advisory Group Meeting

October 13, 2016

PPL companies

Agenda

- Welcome/Introductions
- Review of Kentucky state law regarding opt-out
- DSM Opt-out criteria proposal to meet KRS 278.285
  - "Industrial" definition
  - "energy intensive" definition
  - Implementing cost effective energy efficiency measures
- Next steps

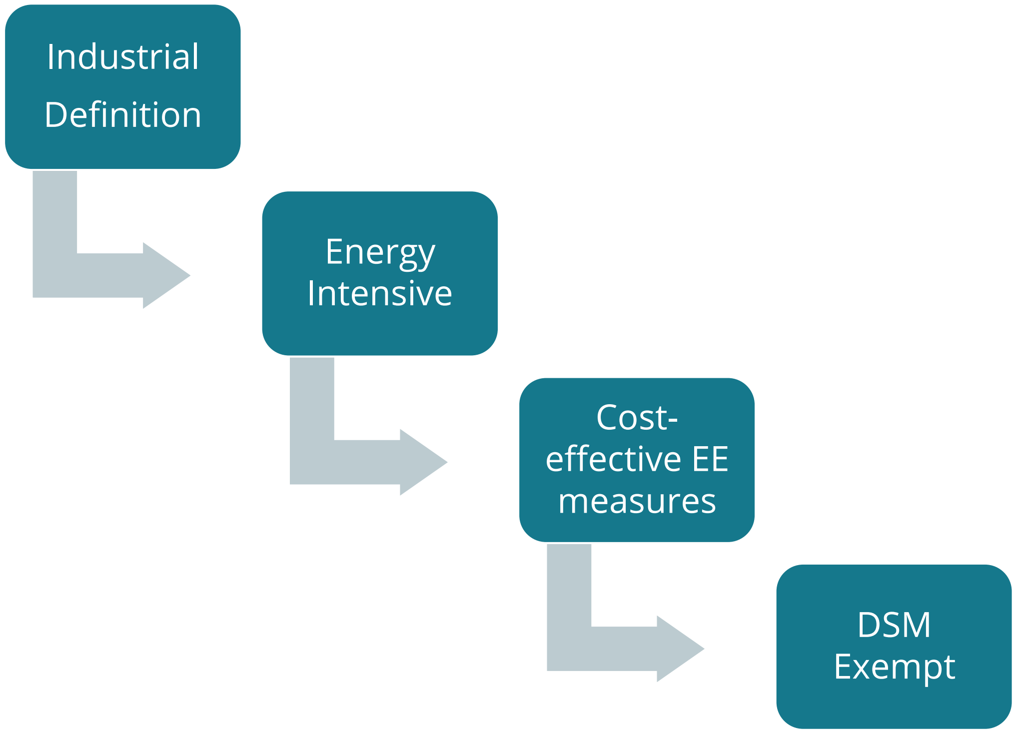
LG&E KU
PPL companies

Opt-out Current Kentucky State Law: KRS 278.285

- (3) The commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The commission shall allow individual **industrial customers** with **energy intensive processes** to implement **cost-effective energy efficiency measures** in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

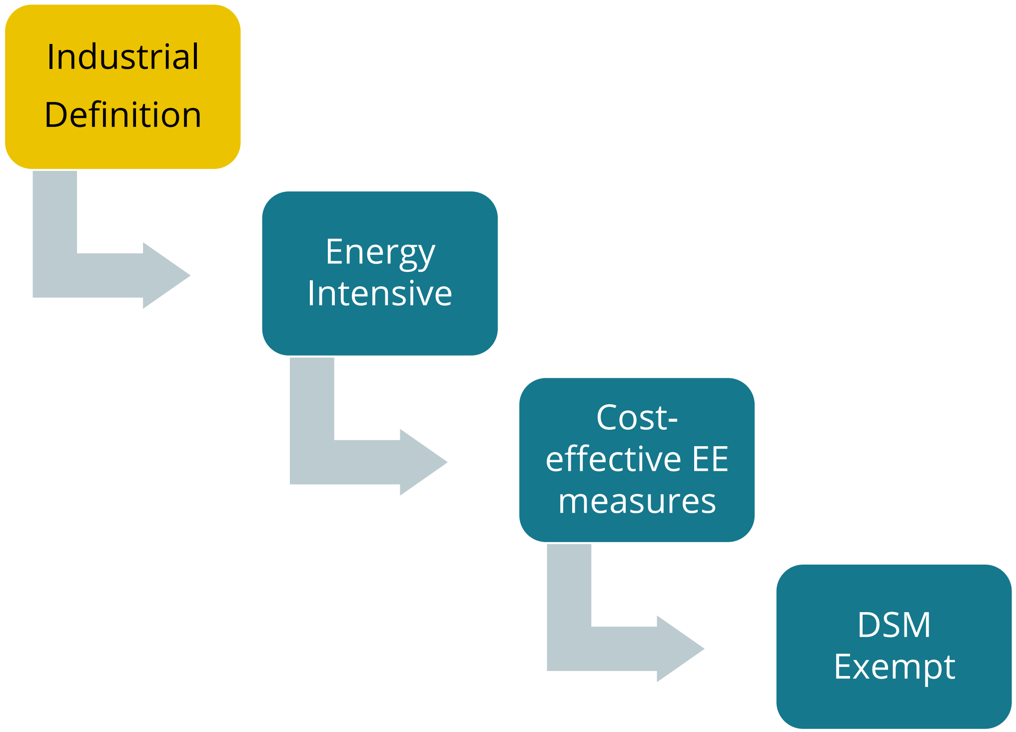
Emphasis added

Steps to DSM exemption: KRS 278.285



LG&E KU
PPL companies

Steps to DSM exemption: KRS 278.285



Industrial definition for LG&E-KU Electric

Current

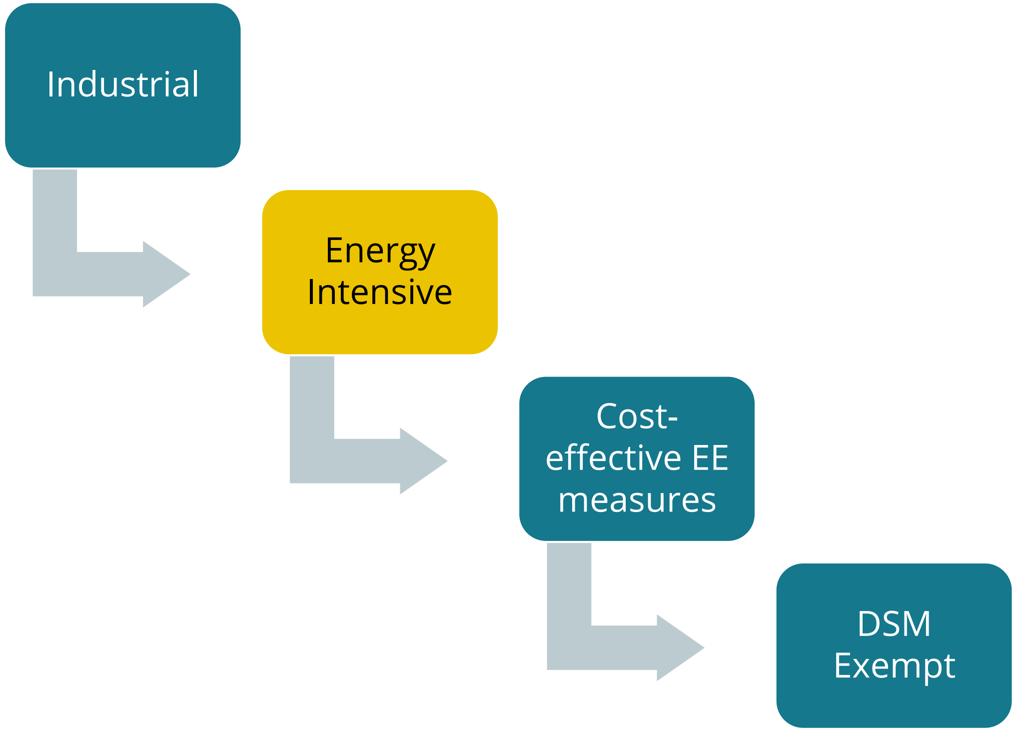
- "[N]on-residential customers will be considered 'industrial' if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33."

Proposed

- "[N]on-residential customers will be considered 'industrial' if they are engaged in activities primarily using electricity in a process or processes which either involve the extraction of raw materials from the earth or a change of raw or unfinished materials into another form or product."

LG&E KU
PPL companies

Steps to DSM exemption: KRS 278.285



Use rate level (tariff) to determine energy intensity

Advantages for customers and the company

- Simplifies process of determining “energy intensive”
  - Rate determines intensity level
  - Aligns with tariffs designed for large energy needs
  - Eliminates subjectivity related to setting a MW limit
  - Allows the customer to readily determine if they qualify for the “energy intensive” portion of the exemption under the statue – Tariff is stated on the customer’s bill
  - Simplifies DSM Program management – improves program delivery for customers.

Tariffs for non-residential consumption

- Specific tariffs
  - GS: 12 month average monthly demand <50 kW (secondary)
  - PS: 12 month average monthly demand 50 – 250 kW (secondary) 0 – 250 kW (primary)
  - TOD Secondary: 12 month average monthly demand 250 kW – 5,000 kW
  - TOD Primary: 12 month average monthly minimum demand > 250 kVA
  - RTS: Transmission service, 12 month average monthly minimum demand > 250 kVA
  - FLS: fluctuating with monthly demand > 20 MVA

LG&E KU
PPL companies

Current characteristics of industrial customers by tariff

	Average of kW or kVA	Max of kW or kVA	Min of kW or kVA	Average of FC Annual kWh	Number of Contracts
GS	178	888	49	372,094	255
PS Sec	234	1,939	51	882,869	460
PS Pri	336	2,470	58	1,030,353	44
TODS	707	2,645	52	3,587,564	285
TODP	3,831	76,238	250	19,751,749	219
RTS & FLS	15,487	192,168	250	71,071,776	40

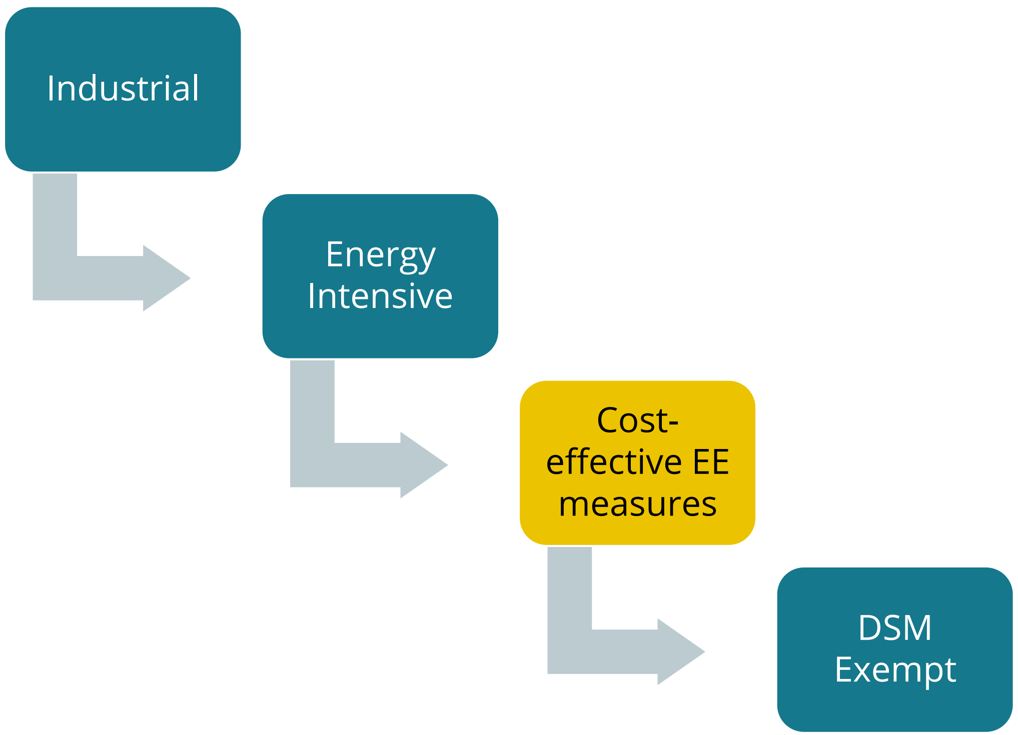
Current characteristics of industrial customers by tariff – energy intensive

	Average of kW or kVA	Max of kW or kVA	Min of kW or kVA	Average of FC Annual kWh	Number of Contracts
GS	178	888	49	372,094	255
PS Sec	234	1,939	51	882,869	460
PS Pri	336	2,470	58	1,030,353	44
TODS	707	2,645	52	3,587,564	285
TODP	3,831	76,238	250	19,751,749	219
RTS & FLS	15,487	192,168	250	71,071,776	40

Energy Intensive

LG&E KU
PPL companies

Steps to DSM exemption: KRS 278.285



Implementing Cost Effective Energy Efficiency Measures

- Any industrial customer that wants to opt-out of DSM and meets both the industrial and energy intensive definitions would provide a letter to LG&E or KU on their company letter head or fill out a form online that would include the following:

  – Account number with meter or copy of the bill stating that the energy used through this meter is for the purposes of converting raw or unfinished materials into another form or product or extracting raw materials from the earth.

  – Positively state that they invested in energy efficiency measures with details about what was completed.

LG&E KU
PPL companies

Implementing Cost Effective Energy Efficiency Measures

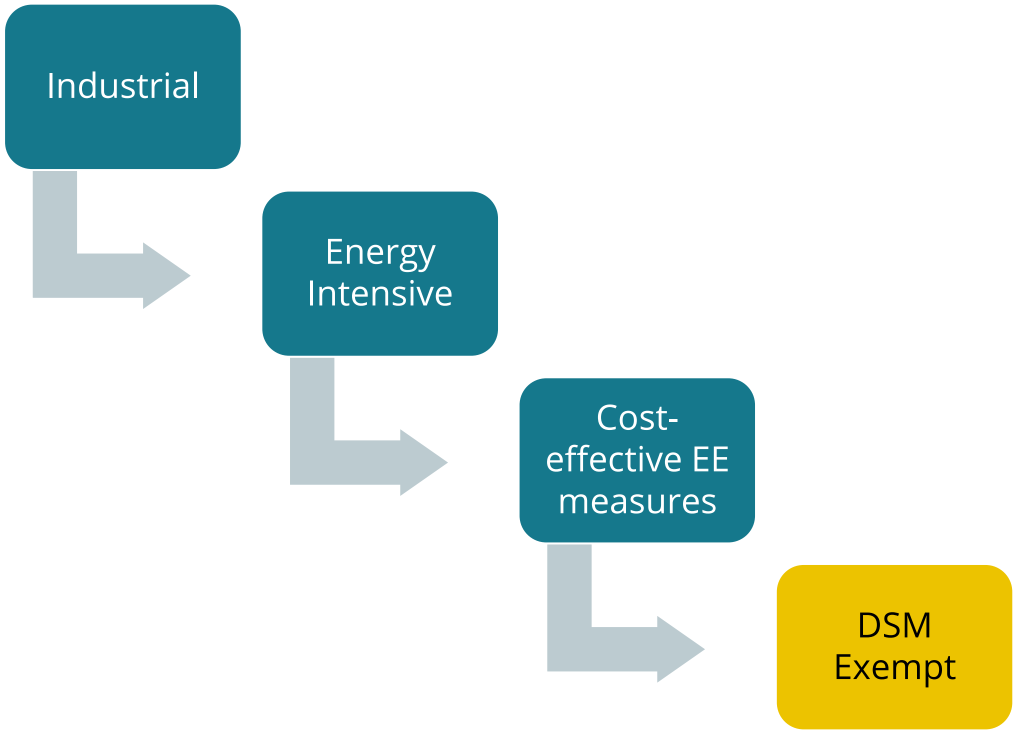
- Request that their meter or account be excluded from DSM charges

- With Company receipt of letter or form and validation of appropriate rate for "energy intensive", an industrial customer would be excluded from DSM charges until the same industrial customer elects to participate at some point in the future.

- Any industrial customer who opts out of the DSM program and subsequently elects to participate in utility DSM programs, and thus pay DSM charges, will not be allowed to exercise an opt-out for a period of three years from the time they commence participation.

LG&E KU
PPL companies

Steps to DSM exemption: KRS 278.285



In Summary

Advantages for customers and company

- Industrial definition clarifies the identification of an industrial customer.
- Tariff simplifies process of determining “energy intensive”
  - Rate determines intensity level
  - Aligns with tariffs designed for large energy needs
  - Eliminates subjectivity
- Determination of “implementing energy efficiency measures”
  - Letter or form stating customer meets the criteria and has installed cost-effective measures
- Residential and non-residential classification simplifies implementing DSM Programing

LG&E KU
PPL companies

Next steps

- Next meeting – early 2017

- Review planning and timeline for next EE filing – target February 2018

LG&E KU
PPL companies

Appendix

Current DSM Exemption Language

Same language for LG&E and KU

P.S.C. No. 17, Original Sheet No. 86, Section "AVAILABILITY OF SERVICE"

- Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other nonresidential customers will be defined as "commercial."

MEETING RECORD

Energy Efficiency Advisory Group Meeting

Date:	**October 13, 2016**
Location:	**Fairfield Inn & Suites** 1220 Kentucky Mills Drive Louisville, KY 40299
Participants:	**LG&E /KU:** Eight employees from various departments including Energy Efficiency and Regulatory Affairs **Stakeholders:** Representatives from eleven stakeholder groups
Date Issued:	10/19/16
Issued by:	Kelli Higdon

The following meeting minutes have been prepared to summarize the conversations and issues discussed at the above referenced meeting.

Welcome / Introductions

Greg Lawson, the Manager of LG&E/KU's Energy Efficiency Planning & Development Department, welcomed the meeting participants. He reiterated the purpose for the meeting to the group. All meeting participants then introduced themselves and indicated their company, agency, or organization of affiliation.

Meeting Agenda

Greg Lawson thanked meeting participants for attending and provided an overview of the meeting agenda:

- Welcome / Intros
- Review of Kentucky state law regarding opt-out
- Definition of Industrial
- Definition of Energy Intensive
- DSM Opt-out criteria proposal to meet KRS 278.285
- Next Steps

Industrial Exemption / DSM Opt-Out

Greg Lawson began by reviewing the current Kentucky State Law: KRS 278.285 which states the conditions in which DSM opt-out is allowed. Greg then went through both the current and the proposed definition of an "Industrial" customer. The proposed Industrial definition would remove the NAICS codes.

Next, the proposal of using the rate level (tariff) to determine the definition of "Energy intensive" was presented along with the benefits and simplification that it would bring to the process. Current characteristics of industrial customers were shown by tariff so that a line could be drawn from the groupings that were presented. This grouping clearly identified those customers who could be identified as "Energy Intensive" (those classified under the tariffs: TODP, RTS & FLS) from the others.

Then, the steps to achieve DSM exemption were presented. A customer must:

1. meet the definition of Industrial,
2. be energy intensive, and
3. finally, have implemented cost effective energy efficiency ("EE") measures.

If a customer meets the criteria above, then the customer can send a letter to LG&E/KU stating that this customer, at this meter, meets all the criteria above. There was a discussion of how the implemented EE measures would be verified and that it is not the utility's intention to audit the EE measures reported for each opt-out.

Next Steps

- Some of the topics suggested by the participants for the next meeting are listed below:
  - Share the results of the New Cadmus Potential Study for Residential and Commercial Programs
  - Share the potential programs that would be offered for all programs
- Greg Lawson thanked the participants for their discussions at these meetings. A follow-up meeting was suggested for early 2017. In the interim, it was mentioned that the DSM Advisory Group could reach out with any questions, comments, or issues regarding programming.
- Greg Lawson thanked the participants for their attendance and closed the meeting.