COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00371**

DIRECT TESTIMONY

OF

LARRY W. HOLLOWAY, P.E.

ON BEHALF OF

THE KENTUCKY OFFICE OF THE ATTORNEY GENERAL

FILED: **March 3, 2017**

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CASE NUMBERS 2016-00370 & 2016-00371

DIRECT TESTIMONY OF

LARRY W. HOLLOWAY, P.E.

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Larry W. Holloway. My business address is 6386 Lake Ridge Parkway, Ozawkie, Kansas. I am an independent consultant testifying on behalf of the Kentucky Office of the Attorney General ("OAG").

Q. Briefly describe your education and work experience.

A. I am a registered professional engineer and have worked over 35 years in all aspects of the electric industry; including generation construction, startup, and operations; regulatory oversight, ratemaking and public policy; and utility resource procurement and management.

My professional experience began outside of the electric industry and includes one year as a field engineer for a natural gas utility and two years as a project engineer for an inorganic chemical plant. Since 1981, the majority of my professional experience has been in the electric industry. I have twelve years of construction, design, startup and operations engineering experience with power plants, primarily nuclear. In 1993, I started work at the Kansas Corporation Commission (KCC) as Chief of Electric Operations, Rates and Services. In 1998, I was promoted to Chief of Energy Operations. In March of 2009, I accepted the position of Operations Manager with Kansas Power Pool (KPP), a Kansas municipal energy agency. In September of 2015 I was promoted to Assistant General Manager of Operations. I continue to work at the KPP and do consulting on a part time basis, provided there is no conflict with the responsibilities of my KPP position and I can arrange the necessary time away from my KPP position.

A short summary of my experience and education is attached as Exhibit LWH-1.

Q. Have you previously filed testimony before this Commission, the Federal Energy Regulatory Commission, or any other state regulatory commissions?

A. Yes. I have filed Testimony before this Commission in Docket Nos. 2012-00535 and 2013-00199. I have filed analysis for settlement purposes at the FERC, and I filed testimony in numerous cases before the Kansas Corporation Commission both as a member of KCC Staff and on behalf of KPP. Testimony I have filed before the KCC includes analysis, review and policy recommendations on utility ratemaking; generation reliability, resource acquisition, planning, dispatch, siting, and fuel and operating costs; utility merger proposal savings and benefits; transmission siting, policy, classification, cost recovery and regionalization; energy cost adjustment mechanisms; and disposition of gain on sale of utility assets. For a full listing of these dockets see Exhibit LWH-1.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by the OAG to review the reasonableness of certain Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company (KU) forecasted expenditures for electric transmission, electric distribution enhancements, and gas distribution and transmission projects. Specifically, I address LG&E and KU proposed electric transmission improvements, electric distribution improvements, and LG&E's recovery of gas expenditures.

Q. Are you sponsoring any exhibits?

A. Yes, I have prepared the following exhibits:

1. LWH-1 – Qualifications of Larry W. Holloway, P.E.
2. LWH-2 – KU and LGE Formula Based Transmission Rate Effective June 1, 2016
3. LWH-3 – 2004 FERC Vegetation Management Report
4. LWH-4 - LG&E and KU RTO Membership Analysis

II. ELECTRIC TRANSMISSION

a. Transmission Maintenance and Improvement

Q. Have you reviewed the LG&E and KU ("the Companies") transmission reliability and resiliency improvement program?

A. Yes. Together the Companies propose very significant spending in their transmission infrastructure over the next 5 years. As described by Mr. Thompson:

"…The Companies will spend $177 million in capital between the end of the last base rate case test period and the end of the forecast test period (July 1, 2016 – June 30, 2018), on transmission system integrity, reliability, and resiliency programs. This spending is part of a total of $511 million in transmission capital investments over the five-year period starting in 2017. …"[1]

This program is described in more detail in the Companies' Transmission System Improvement Plan ("TSIP").[2] The following Table provides a summary of these forecasted capital Expenditures:

Table 1	**Forecasted Spending[1]**	
Total Project/Asset Class for the Companies ($millions)	**Two-Year July 1, 2016 through June 30, 2018**	**Annual Average**
Replace Defective Line Equipment (wood poles, cross-arms, insulators)	92	46
Replace Overhead Lines	13	6.5
Improve Line Sectionalizing for Reliability	15	7.5
Replace Circuit Breakers	13	6.5
Replace Protection and Control Systems	12	6
Replace Misc. Substation Equipment	1	0.5
Replace Underground Cable	9	4.5
Replace Control Houses	7	3.5
Replace Switches	2	1
Transmission Plan Total	**164**	**82**
Resiliency	**13**	**6.5**
Total	**177**	**88.5**
[1] See page 27 Thompson Direct Testimony		

[1] See l.20, p.26 through l.1, p.27 of the Direct Testimony of Paul W. Thompson, filed November 23, 2016 in these proceedings ("Thompson Testimony").
[2] See Exhibit PWT-2 of the Thompson Testimony.

It should be noted that despite the description by the Companies as an improvement program, $92 million, or about 52% of the 2 year forecasted expenditures of $177 million, are to replace defective equipment. More importantly, this is a dramatic increase from historic expenditures, both overall, and for defective equipment replacement, as shown in the following table:

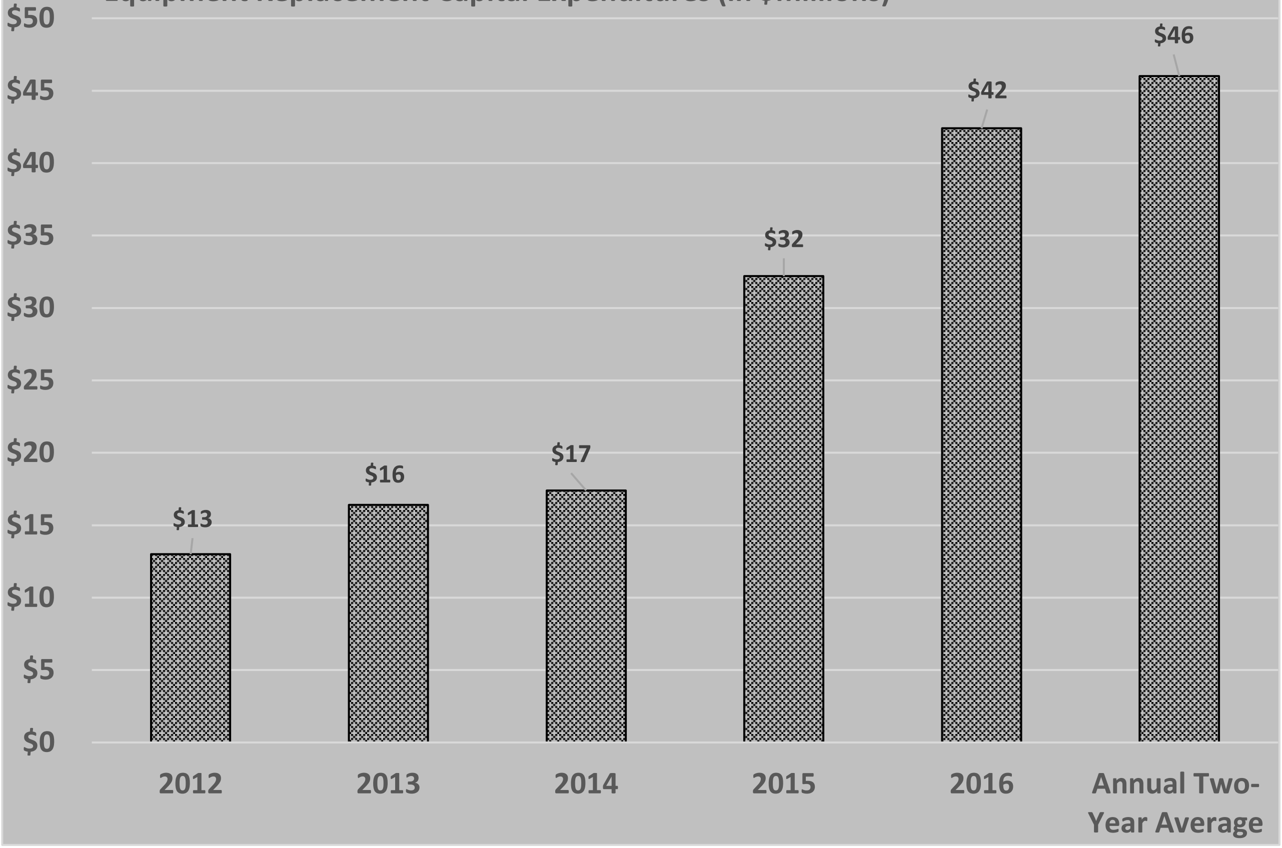
Table 2	Historic Capital Spending[1]					Forecast
Total Project/Asset Class for the Companies ($millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**Annual Two-Year Average**
Replace Defective Line Equipment (wood poles, cross-arms, insulators)	$13	$16	$17	$32	$42	$46
Replace Overhead Lines	$4	$1	$1	$1	$3	$7
Improve Line Sectionalizing for Reliability	$0	$0	$0	$3	$1	$8
Replace Circuit Breakers	$8	$6	$2	$5	$6	$7
Replace Protection and Control Systems	$1	$1	$2	$3	$4	$6
Replace Misc. Substation Equipment	$0	$0	$0	$0	$1	$1
Replace Underground Cable	$0	$0	$0	$0	$0	$5
Replace Control Houses	$0	$1	$0	$3	$5	$4
Replace Switches	$1	($0)	$0	$1	$0	$1
Transmission Plan Total	**$27**	**$25**	**$22**	**$48**	**$62**	**$82**
Resiliency	**$4**	**$4**	**$0**	**$2**	**$0**	**$7**
Total	**$31**	**$29**	**$22**	**$50**	**$63**	**$89**
[1] LG&E values from Response to AG1-388 in Docket No. 2016-371 KU values from Response to AG1-363 in Docket No. 2016-370						

Q. Does this mean that the Companies have experienced an unusual amount of defective or broken transmission equipment since 2015 and are forecast to experience even more?

A. That is unlikely. It is far more likely that the Companies have either not been looking or inspecting for defective poles, cross-arms, insulators, etc, or have failed to replace defective equipment that has been discovered. While there are multiple initiatives in the Companies' program to improve transmission reliability, certainly identifying, repairing and replacing defective equipment should be a top priority. This is readily apparent from the following illustration:[3]

[3] Information combined from AG1-388 in Case No. 2016-371 and AG1-363 in Case No. 2016-370, see Table 2, *supra*.

Figure 1. Historic and Forecast LG&E and KU Defective Transmission Equipment Replacement Capital Expenditures (in $millions)



Q. How significant is the level of capital expenditures the Companies are proposing for transmission reliability and resilience?

A. Very significant. Exhibit LWH-2 is the Companies' Formula Based Transmission Rate ("FBTR") spreadsheet effective June 1, 2016 based on the combined LG&E and KU Federal Energy Regulatory Commission ("FERC") form 1.[4] As shown on line 14, page 11 of Exhibit LWH-2, at the end of 2015 the Companies had $708,981,812 in net transmission plant. As discussed, the Companies propose capital expenditures of $511 million over the next 5 years. As shown on line 10, page 12 of Exhibit LWH-2,

[4] This is available on the www.oasis.oati.com website under KU and LG&E.

2015 transmission annual depreciation expense was roughly $22 million. Conservatively assuming that there will be an average of $30 million a year in transmission depreciation expense and retirements each of the next 5 years, it still appears that net transmission plant will increase by over $350 million, or by about 50%, by the end of 2022. Furthermore, assuming $46 million a year in expenditures for defective equipment replacement over the five-year period, about 40% of the proposed capital expenditures will be for defective equipment replacement.

Q. In your opinion, is this an unusually large amount of capital expenditures for replacing defective equipment?

A. Yes it is. It is important to remember that often when a piece of transmission equipment is replaced it may be 30, 40 or more years old. The replacement cost of that equipment is likely many times the original cost, even if nearly identical equipment is used. Nonetheless, assuming the forecast is accurate, it appears that the Companies have been neglecting needed maintenance on their transmission assets. In fact, when asked to explain the accelerated level of forecasted expenditures for defective equipment replacement the Companies' response was that "the Company has increased defective equipment replacements in an effort to reduce the backlog of defective equipment identified through inspection programs [emphasis added]."[5]

[5] See response to AG 2-125c in Case No. 2016-00371 and AG 2-110c in Case no. 2016-00370.

Q. Do you have any observations about other elements of the Companies' Transmission Plan?

A. Yes. As shown on Table 2, in all categories except "Replace Control House" the forecasted average annual spending is much greater for the next two years than any of the previous five years. Additionally, even though the "Replace Control Houses" category average 2017 and 2018 expenditures are $4 million, slightly less than the 2016 level of $5 million, it is still double the 2011 through 2014 average of $2 million. It is obvious from a simple inspection of these categories, as shown in Table 2, that much-needed transmission equipment maintenance and replacement has been deferred.

Q. Are the Companies taking any other actions to increase the reliability of their transmission system?

A. Yes. As stated in the Direct Testimony of Mr. Thompson, "the Companies are transitioning from their just-in-time tree trimming program to a five-year cycled approach to vegetation management."[6] Later in his testimony, Mr. Thompson further elaborates on this change: "Instead of frequent line inspections and reacting to hazard trees and encroachments to the Companies' right of way, the Companies will implement a five-year cycled approach to vegetation management and a hazard tree identification and removal program."[7] These changes were in response to

[6] See l.1 to l.3, p.30 of the Thompson Testimony.
[7] See l.11 to l.14, p.30 of the Thompson Testimony.

suggestions made in a study conducted by Environmental Consultants, Inc. ("ECI") and commissioned by the Companies.[8]

Specifically, ECI made twelve recommendations, including transitioning to cyclical maintenance and development of a hazard tree ground patrol.[9]

Q. Did ECI specifically recommend a 5-year vegetation clearance cycle for transmission?

A. Not exactly. They recommended that the Companies consider adding 46 crews to meet the additional workload requirements to implement a 5-year cycle.[10]

Q. Were you surprised at the transition to a 5-year vegetation clearance cycle for the Companies transmission?

A. Yes. While this seems to be typical of distribution clearance programs, many transmission owners had implemented such cyclical programs long ago and the FERC has expressed concerns regarding the adequacy of even a 5-year vegetation clearance cycle for transmission. The attached Exhibit LWH-3 is a report from the FERC in 2004 following its investigation of the August 14, 2003 Northeast and Midwest blackout. At that time the FERC observed that a five-year cycle is the industry norm and that the five-year cycle is insufficient to maintain reliability.[11] The fact that the Companies are just now moving toward a 5-year cycle over 12 years after the FERC has questioned its adequacy, and the fact that the Companies' own

[8] See p.20 of Exhibit PWT-2 of the Thompson Testimony.
[9] See p.4 to p.5 of the 55-page attachment to the Companies response to KIUC1-30 in Case No. 2016-00370 and in response to KIUC1-31 in Case No. 2016-00371.
[10] Ibid., p.5.
[11] See page 12 of Exhibit LWH-3.

consultant believes 46 additional crews are necessary to achieve even a 5-year cycle, is alarming. Regardless of the possible need to address additional vegetation management, it is hard to imagine the Companies have the ability to "ramp up" as rapidly as their filing would indicate.

Q. Are you recommending any changes to the vegetation management program itself or to the level of spending for vegetation management?

A. No. I discuss the subject only to illustrate the significant level of changes the company is considering to address past neglect of its transmission assets.

Q. How does this proposed change in vegetation management compare with the Companies' transmission reliability initiative?

A. Considering that over 40% of the Companies' capital expenditures on transmission over the next 5 years are for replacing defective equipment, increased expenditures to achieve what many believe to be an inadequate vegetation clearance cycle seems to indicate a long period of neglect of the Companies' transmission system. Furthermore, much of the Companies' Transmission Plan involves what should be routine maintenance and replacements as a result of inspections. One would expect such levels of maintenance expenditures to be relatively similar from year to year. The fact that there is an expected acceleration and increase in these expenditures indicates the Companies have developed a large backlog of needed maintenance and replacements and have not devoted adequate resources to working off identified inspection findings as they occur.

Q. Do you have a suggestion for the Commission?

A. Yes. First, I believe there are distinct implications which the Commission should consider on this subject. The Companies' failure to devote adequate resources in the past few years to reduce the backlog of needed transmission equipment replacement and repair must be contrasted with its proposed significant transmission spending increases. The Commission should question the ability of these resources to greatly expand not only transmission equipment and repair, but also other transmission initiatives. Simply put, if the Companies cannot achieve needed levels of maintenance now, the Commission should question their ability to accelerate such efforts in the fully forecasted test year.

Second, in the context of this immediate proceeding, I believe the Commission should closely scrutinize the overall level of transmission-related spending, especially regarding that portion of proposed spending that does not relate to replacement of defective equipment. Accordingly, the Commission should strongly consider an adjustment to the level of spending for such programs.

Third, in the longer-term context, I believe the Commission may wish to consider an investigation of the ability, commitment and willingness of LG&E and KU to maintain, improve and operate transmission in the Commonwealth of Kentucky. My understanding is that LG&E and KU have retained the services of an independent transmission operator (ITO) to operate their transmission system. Today there are many examples where transmission assets are owned, maintained and/or operated by an independent transmission company. While there are definitely advantages and disadvantages to both those models and the traditional vertically integrated utility, one advantage of separate transmission ownership is that the independent transmission company is not distracted by other demands for capital or management attention, because its only focus is transmission service. The Commission may want to consider exploring the nature of the agreement between LG&E-KU and their ITO, and whether any modifications to their agreement would better serve the retail and wholesale transmission customers of LG&E and KU.

b. Transmission Control

Q. Does either LG&E or KU currently participate in a Regional Transmission Organization ("RTO")?

A. No. In fact, the Companies have not performed a study of the cost vs benefits of such an RTO membership since December 11, 2012, over 4 years ago. At that time the Companies performed their own study. This study is attached as Exhibit LWH-4.[12]

Q. Do you have any concerns regarding this study?

A. Yes. First, this was not an independent study. Second, the study should be updated to reflect current market and tariff provisions of both MISO and PJM. Third, it appears the assumptions may be overly simplistic.[13]

Q. Why do you believe the assumptions may have been overly simplistic?

A. First, it is not clear why there would be an assumption of no FTR/ARR congestion costs. Congestion costs, or congestion rights, are a valid source of revenue or costs

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[12] Provided in response to AG1-409 in Case No. 2016-00370 and in response to AG1-441 in Case No. 2016-00371.

[13] See section 3 of Exhibit LWH-4.

in an RTO membership. Neglecting to consider these costs could greatly impact either the costs or benefits of RTO membership. While these costs were difficult to calculate at the time, as indicated in the study, assuming they do not exist is too simplistic. Since 2012 the ability of analytical tools to estimate FTR/ARR congestion costs has greatly improved. Whereas, five years ago utilities signing purchase power agreements for wind generation, for example, often only reviewed the seller's ability to obtain transmission service, today most buyers perform a study of congestion costs before selecting a seller. Furthermore, not only have congestion cost analytical tools improved, today there is far more public historic congestion cost information available for such analysis.

Second, there is an assumption of no changes in Locational Marginal Prices ("LMP") due to RTO expansion plans. While RTO expansion plans 4 years ago may not have affected LMPs at that time, today, four years later, major changes in RTO membership and generation makeup have occurred. As indicated in the 2012 study MISO membership and PJM membership have changed since the study was performed. The effects of Entergy membership in MISO, for example, can now be calculated with historic data.

Third, the 2012 study did not consider possible income streams from sales into the PJM or MISO capacity markets. Since 2012 these markets have greatly matured and changed. Any updated study should carefully consider how sales or purchase obligations into these markets could affect the cost benefit analysis.

Fourth, one of the advantages of participating in a structured market, such as PJM or MISO, is that all units are dispatched by the market, and the market allows cost recovery of the dispatched units. While it is relatively simple to share the operating costs of jointly owned base load units, such as coal and hydro plants, it is relatively complicated to fairly share costs for cycling or peaking units. For example, if two entities each own shares of a combustion turbine, and combustion turbine maintenance is based upon unit starts, then if one entity causes the combustion turbine to start, that entity should be allocated a start based allocation of maintenance costs. However, if the jointly owned unit is dispatched by a structured market, such as PJM and MISO, the entities can share the market revenue to offset their shared costs. It should be noted that KU and LG&E jointly own the Trimble County combustion turbines and these units have start based maintenance costs,[14] yet these maintenance costs are not tracked based on which entity caused the unit start. Furthermore, careful allocation of such generation costs are even more important when both entities are affiliates, as is the case with LG&E and KU.

Q. Why do you believe the study should be updated to reflect PJM and MISO market and tariff changes?

A. First, as discussed the membership of PJM and MISO has changed since the 2012 study and thus the markets have also changed. Second, the generation makeup of both markets have changed dramatically in the last 4 years, with increased

[14] See response to AG2-100 in Case No. 2016-00370.

dependence on natural gas units, early retirements of coal units, and increased wind and solar generation. Finally, regulatory changes by the FERC over the past 4 years have had an effect on electric markets in all regions. For example, changes brought about related to electric and gas market coordination have affected both PJM and MISO operations.

Q. Why do you believe that KU and LG&E should have an independent firm perform an updated cost benefit analysis of RTO membership?

A. It is always good to get an unbiased third party opinion. Furthermore, as indicated in the 2012 study, KU and LG&E express concern that "Membership in PJM would almost certainly pit LKE interests against those of traditional PPL companies on matters of significance to all concerned."[15] While this may or not be a legitimate concern, it is sure to affect the objectivity of any analysis performed in house. Regardless, this Commission should be focused on the feasibility of RTO membership as it applies to its own jurisdictional utilities, LG&E and KU.

Q. What recommendation do you have for the Commission?

A. I would recommend that the Commission Staff work with the Companies to develop and issue a Request for Proposal ("RFP") for an independent entity to perform a cost benefit study and analysis of LG&E and KU RTO membership and the current ITO's performance. I would suggest that Commission Staff select the independent entity, subject to agreement by the Companies and the two large broad based consumer

[15] See section 7.2 of Exhibit LWH-4.

advocates, the KYOAG and the Kentucky Industrial Utility Customers, Inc. ("KIUC"). Regardless of the process, there should be a consensus between Commission Staff, KYOAG, KIUC and the Companies regarding the scope of the study and analysis and the selection of the independent entity.

Finally, I note that OAG witness Paul Alvarez in his testimony raises two additional issues that should be evaluated within the overall context of such an independent analysis.

III. ELECTRIC DISTRIBUTION AUTOMATION

Q. Have you reviewed the Companies' distribution automation ("DA") initiative?

A. Yes. As described by Mr. Thompson there are two primary components to the DA program. One component describes acquiring and deploying a Distribution Supervisory Control and Data Acquisition ("DSCADA") system and Distribution Management System ("DMS") software.[16] The other component is installation of 1,400 SCADA (or in this case DSCADA) capable reclosers.[17]

Q. Is there a projected expenditure plan for the DA program?

A. Yes. The LG&E and KU Electric Distribution Operations Distribution Reliability and Resiliency Improvement Program is provided as Exhibit PWT-5 to the Thompson Testimony. Table 3 of Exhibit PWT-5 provides the 2016 through 2022 spending forecast for the program:[18]

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[16] See l.9 to l.13, p.39 of Thompson Testimony.
[17] Ibid., l.1 to l.8, p.39.
[18] See section 5.1.2 of Exhibit PWT-5 of Thompson Testimony.

Table 3: Breakdown of Investments within DA Plan — 2016–2022									
					(All Dollars in Thousands)				
DA Plan Detail		2016	2017	2018	2019	2020	2021	2022	Total Spend
Reclosers			$7,120	$21,672	$20,675	$17,608	$17,608	$17,617	$102,300
DMS/DSCADA	$		$2,500	$2,922	$700				$6,122
Communication		80	$800	$656	$625	$595	$595	$584	$3,935
Total	$	80	$10,420	$25,250	$22,000	$18,203	$18,203	$18,201	$112,357

Q. Do you have any concerns regarding the DA program?

A. Yes. I believe the forecasted investment timetable illustrates problems with the program implementation. I find it unlikely that the SCADA capable recloser schedule can be maintained or that the proposed recloser installations can be optimally located until the Companies complete installation and full operation of their DMS/DSCADA systems. In fact, I believe it is unreasonable to assume that the Companies can or even should attempt to achieve their proposed level of spending on the SCADA capable reclosers over the next few years.

Q. Why do you believe the proposed implementation schedule of the program is unreasonable?

A. For several reasons. First, and most important, the schedule anticipates that the DSCADA system will not be fully deployed until early 2019. Second, given other information technologies the company proposes to implement over the next few years I believe it is unlikely the scheduled DA investments can be reasonably achieved.

Q. Why does deployment of the DSCADA system affect the reasonableness of implementing the remaining component of the DA program, the SCADA capable reclosers?

A. The DSCADA system vendor must be selected, the equipment purchased and installed and troubleshooting must occur before there is any need for the installation of SCADA capable reclosers. Doing both at the same time simply makes no sense. Such an approach is akin to building the roof while pouring the foundation. Additionally, until the DSCADA system is thoroughly deployed, programmed and troubleshot, it would be imprudent to connect it to equipment that it could inadvertently operate.

Q. Why do you believe it would be unreasonable to locate and install SCADA capable reclosers before implementing other information technologies?

A. First, installation of DSCADA and DMS, as well as Advanced Metering System ("AMS") deployment will require extensive use of the Companies' Information Technology ("IT") personnel. Logistically, it would appear that deploying all of these interconnected systems at the same time would strain these limited resources and could affect the efficiency of the implementation and deployment. Furthermore, given the expense of the Companies' AMS initiative the Commission should make sure that the information gained is utilized optimally.[19]

Second, without input from information gained from the "data acquisition" portion of DSCADA, as well as DMS and AMS, SCADA capable reclosers may not

[19] See the testimony of OAG witness Paul Alvarez.

be optimally located. Given the high cost of each installation, it is reasonable to first implement DSCADA and DMS before locating and installing the SCADA capable reclosers. While the Companies argue they will not use AMS information to locate reclosers,[20] moving the reclosers by even a few spans could affect the ideal deployment and reliability benefits of sectionalizing the circuit properly. Furthermore, if the Commission decides to grant the Companies' request to implement AMS, at the very least, information gained by this expensive initiative should be utilized to optimally locate reclosers. Furthermore, lessons learned from cellular communications for the DSCADA system could lead to equipment changes and location changes for recloser DSCADA communication equipment.

Q. What do you recommend regarding deployment of the DA project?

A. I believe the project schedule should be modified to defer the installation of SCADA capable reclosers for 2 years as follows:

[20] See response to AG2-103e in Case No. 2016-00370.

Table 4 - Proposed Revision to the Companies DA Program Schedule									
(All Dollars in Thousands)									
DA Plan Detail	2017	2018	2019	2020	2021	2022	2023	2024	Total Spend
Reclosers			$7,120	$21,672	$20,675	$17,608	$17,608	$17,617	$102,300
DMS/DSCADA	$2,500	$2,922	$700						$6,122
Communication	$205	$61	$800	$656	$625	$595	$595	$584	$4,121
Total	$2,705	$2,983	$8,620	$22,328	$21,300	$18,203	$18,203	$18,201	$112,543
Note: assume communication reduction by $595 for 2017 and 2018 to reflect recloser delay									

Are you recommending an adjustment in the Companies' filing?

A. Yes. Based upon my recommendation to delay implementation of the recloser installations for 2 years, the following will be the adjustment to the total companies' DA investment:

Table 5 - Reduction to FFTY DA Expenditures from Recloser Delay			
		(All Dollars in Thousands)	
DA Plan Investment	2017	2018	FFTY
Company Proposed Reclosers	$7,120	$21,672	$14,396
Recommended Recloser Delay	0	0	$0
Adjustment to FERC Acct 365	($7,120)	($21,672)	($14,396)
Company Proposed Communication	$800	$656	$728
Recommended Recloser Delay	$205	$61	$133
Adjustment to FERC Acct 397	($595)	($595)	($595)

Q. How would you recommend allocating this adjustment between LGE and KU electric distribution?

A. Based on the Companies' response for expenditures for both LG&E and KU recloser installations, I have developed the following adjustment for LG&E and KU DA investments based on the Companies' assumptions when evaluating the DA project:

Table 6 - Reduction to FFTY DA Expenditures from Recloser Delay for KU and LG&E Electric Distribution			
	(All Dollars in Thousands)		
DA Plan Investment	2017	2018	FFTY
Proposed KU Recloser Investment	$2,848	$8,669	$5,758
Proposed LG&E Recloser Investment	$4,272	$13,003	$8,638
Overall Account 365 Adjustment	($7,120)	($21,672)	($14,396)
Overall Account 397 Adjustment	($595)	($595)	($595)
KU Account 365 Adjustment	($2,848)	($8,669)	($5,758)
KU Account 397 Adjustment	($238)	($238)	($238)
LG&E Account 365 Adjustment	($4,272)	($13,003)	($8,638)
LG&E Account 397 Adjustment	($357)	($357)	($357)

For 2017 and 2018 investment on a KU/LG&E basis see 2016-00370 PSC1-54, ratio used to allocate adjustment

IV. GAS LINE TRACKER MECHANISM

Q. Do you have any recommendations specific to LG&E?

A. Yes. I have reviewed the need for a new Gas Line Tracker ("GLT") mechanism as proposed by LG&E.

Q. Why does LG&E believe it needs a new GLT mechanism?

A. According to Mr. Bellar, it is because they are nearing completion of programs under the current GLT mechanism and would like to begin new programs to replace steel customer service lines and targeted removal of county loops and steel curbed services over the next 15 years. In addition, LG&E proposes to modernize its transmission pipelines under the same program.[21]

Q. Does there appear to be a difference between these programs and the original GLT programs?

A. Yes. The original GLT programs were essentially considered critical enough to be completed, or substantially completed, in five years. Except for the initiative to modernize LG&E's gas transmission program, the remaining programs under the new GLT mechanism have a 15-year time frame. While I would not dispute that these initiatives will improve safety and are needed over time, the length of the program implies that these upgrades may be completed methodically over a long period of time. A program that takes place for such an extended period of time does not appear to be any different than normal prudent maintenance, upgrades and improvements. It is difficult to understand why such a long term program should be recovered under a separate rate mechanism such as the GLT.

Q. Why is there a concern about recovering the costs of a long term program under a special rider such as the GLT mechanism?

A. Over the course of 15 years there can be large changes in the amount of customers, sales, net plant, and all other aspects of a utility's costs. Regardless of these broad changes on the utility's costs, a single issue rate mechanism such as the GLT will examine only a small piece of the utility's operations. Furthermore, it would appear

[21] See l.19, p.15 through l.7, p.16 of the Direct Testimony of Lonnie E. Bellar, filed November 23, 2016 in Case No. 2016-00371 ("Bellar Testimony").

that LG&E does not need to be concerned about recovery of these costs in between rate proceedings.

Q. Why do you believe LG&E will have ample opportunity to recover these expenditures over the foreseeable future without the GLT mechanism?

A. First, LG&E is using a fully forecasted test year mechanism so costs of these programs over the next 16 months can be incorporated into their rates without the GLT mechanism. Second, given the level of capital expenditures forecasted by the Companies over the next 2 years, there is simply no reason to place new programs under the GLT mechanism at this time. Third, LG&E is on a two-year rate case cycle, hence there is virtually no regulatory lag in recovering its costs.

Q. Why does the Companies' capital expenditure forecast indicate there is no need to expand the GLT mechanism at this time?

A. The Companies forecast capital investments of approximately $2.2 billion between June 30, 2016 and the end of the fully forecasted test year on June 30, 2018:

> "… The current rate cases are based on the 13-month average capital investment at LG&E and KU for the year ended June 30, 2018. The use of average capitalization rather than end of period capitalization means that there was some increase in capitalization as of June 30, 2016, that was not yet reflected in base rates from the Companies' last rate case. Likewise, there will be some amount of capitalization as of June 30, 2018, that is not reflected in this rate case filing. However, as such capital investment not fully included in the revenue requirement calculations in this case and prior case are relatively consistent, capital spend between the end of the previous test year and the test year used in this case represents a good proxy of the capital spend driving the increase requested in this case. LG&E and KU have invested and project to invest more than $2.2 billion of

capital into their operations over this two-year period, approximately $1.1 billion for each company."[22]

Furthermore, LG&E forecasts that $679.2 million of its forecasted $1,145.4 million in capital investment will be recovered without benefit of a separate rate mechanism such as the GLT over this two-year period. [23] Given that the same effect of "average capitalization as compared to end of period capitalization" lamented by Mr. Blake will occur in this case, there is simply to assume that LG&E will return to the Commission for another rate increase before the end of the fully forecasted test year, June 30, 2018.

Q. What is your recommendation regarding expansion of the GLT mechanism?

A. Given that LG&E will need to return to the Commission in the near future for another rate increase, and that a good portion of the proposed programs are long term initiatives, there is simply no reason to expand the GLT mechanism at this time. Furthermore, no initiatives should be added to the GLT mechanism, even if there is not apparent forthcoming future rate proceeding, unless such programs have a limited duration. As to that duration, five years would seem to be a reasonable maximum time period for any such initiative.

Q. Does this conclude your testimony?

A. Yes.

[22] See l.19, p.3 through l.2, p.4 of the Direct Testimony of Kent W. Blake, filed November 23, 2016 in Case Nos. 2016-00370 and 2016-00371 ("Blake Testimony").
[23] Ibid., l.5, p.4 to l. 4, p.5.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	CASE NO. 2016-00371

AFFIDAVIT OF Larry Holloway, P.E.

State of Kansas)

Larry Holloway, P.E., being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and the Schedules attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Larry Holloway PE

Larry Holloway, P.E.

SUBSCRIBED AND SWORN to before me this 24 day of February, 2017.

Diana Tweedy

NOTARY PUBLIC

My Commission Expires: 10-13-2020

DIANA TWEEDY
NOTARY PUBLIC
STATE OF KANSAS
My Appt. Exp. 10-13-20

Qualifications of Larry W. Holloway, P.E.

General

Electric industry professional with broad experience in public utility regulation, power plant operations, maintenance and performance testing, transmission service, resource planning, procurement and scheduling, utility load forecasting and planning, project management, and electric utility ratemaking.

Work History and Recent Relevant Experience

Kansas Power Pool (KPP) March 2009 - Present

Assistant General Manager - Operations (Sept 2015 – present)

Operations Manager (March 2009 – Sept 2014)

Preparation of annual budget, including load forecasts, purchase power and fuel costs, generation capacity costs, and pool wide rate design for a wholesale not for profit municipal energy agency that provides 34 municipal utilities with generation supplies and transmission service.

Responsible for securing generation resources and transmission service for KPP members. Oversight of administration of service contracts for transmission scheduling, Information technology, and metering services. Coordinating of regulatory services and responsible for expert testimony on transmission policy and services.

Kansas Corporation Commission (KCC) July 1993 to March 2009

Chief of Energy Operations

Provided electric utility industry expert testimony before the KCC as member of KCC Staff.in over 40 dockets, including dockets involving generating costs and performance,
.
Acted as Commission liaison before many groups including legislative committees, industrial groups, NARUC, environmental groups, civic organizations, utility groups, federal agencies, regional reliability councils, transmission organizations and state social agencies.

Provided presentations, courses and speeches on a variety of KCC and industry issues to many groups including legislative committees, regional transmission organizations, industry conferences and international regulatory bodies.

Wolf Creek Nuclear Plant -WCNOC June 1989 to July 1993
BOP System Engineering Supervisor

Browns Ferry Nuclear Plant- TVA August 1987 to June 1989
Senior System Engineer

Trojan Nuclear Plant – Portland General Electric October 1984 to August 1987
System Engineer III

Wolf Creek Nuclear Plant – Matsco April 1983 to October 1984
Contract Startup Engineer

Burns & Roe – WNP 2 September 1982 to April 1983
Nuclear Design Engineer

Ebasco Inc – Waterford Nuclear Plant June 1981 to September 1982
Construction Engineer

FMC Inc – Inorganic Chemical Plant June 1979 to June 1981
Project Engineer

Kansas Power & Light – Natural Gas Division June 1978 to June 1979
Field Engineer

Education

Univerity of Kansas, Kansas
Bachelor of Science Civil Engineering, December 1977
Bachelor of Science Mechanical Engineering, May 1978
Master of Science Mechanical Engineering, May 1997
Washington State University, Washington
Master of Engineering Management, May 1988

Professional Registration

Registered Professional Mechanical and Civil Engineer, State of Oregon, PE license No. 12989

Expert Witness Testimony

FERC	Provided analysis and affidavit in FERC Docket ER01-1305 for the KCC, which led to a negotiated settlement in an affiliate purchase power agreement between Westar Energy and Westar Generating Inc., and affiliate.
KCC	KCC Staff testimony in Docket Nos. 95-EPDE-043-COM, 96-KG&E-100-RTS, 96-WSRE-101-DRS, 96-SEPE-680-CON, 97-WSRE-676-MER, 98-KGSG-822-TAR, 99-WSRE-381-EGF, 99-WSRE-034-COM, 99-WPEE-818-RTS, 00-WCNE-154-GIE, 00-UCUE-677-MER, 01-WSRE-436-RTS, 01-WPEE-473-RTS, 01-KEPE-1106-RTS, 02-SEPE-247-RTS, 02-EPDE-488-RTS, 02-MDWG-922-RTS, 03-MDWE-001-RTS, 03-WCNE-178-GIE, 03-MDWE-421-ACQ, 03-KGSG-602-RTS, 04-AQLE-1065-RTS, 04-KCPE-1025-GIE, 05-EPDE-980-RTS, 05-WSEE-981-RTS, 06-WCNE-204-GIE, 06-SPPE-202-COC, 06-WSEE-203-GIE, 06-KCPE-828-RTS, 06-KGSG-1209-RTS, 06-MKEE-524-ACQ, 07-WSEE-616-PRE, 07-KCPE-905-RTS, 08-WSEE-309-PRE, 08-KMOE-028-COC, 08-WSEE-609-MIS, 08-MDWE-594-RTS, 08-WSEE-1041-RTS, 08-ITCE-936-COC, 09-KCPE-246-RTS, and 08-PWTE-1022-COC.
	Testimony on behalf of KPP in Docket Nos. 09-MKEE-969-RTS, 11-GIME-497-GIE, 12-KPPE-630-MIS, 15-SPEE-161-RTS, 16-MKEE-023-TAR, 16-KPEE-470-PRE and 16-KCPE-593-ACQ.
KYPSC	Testimony on behalf of the Kentucky Office of Attorney General in Case Numbers 2012-00535 and 2013-00199 before the Kentucky Public Service Commission.

Type of Service	Unit of Measure	June 1, 2016 Point to Point	June 1, 2016 NITS
Hourly Peak	$/MWh	$4.88	n/a
Hourly Off-Peak	$/MWh	$2.29	n/a
Daily Peak	$/MW-Day	$78.00	n/a
Daily Off-Peak	$/MW-Day	$55.00	n/a
Weekly	$/MW-Week	$388	n/a
Monthly	$/MW-Month	$1,683	$1,725
Schedule 1	$/MWh	$0.107	$0.107

Input Data for Annual Update of the LG&E/KU Attachment O Formula Rate

Page 1
Update Year 12/31/2015

Error checks
Form 1 source data
Internal reporting source data

Revenue Credits	KU	LGE	Combined		
Revenue from Grandfathered Interzonal Transactions	0	0	0	to Page 1 of 5, L. 4	Not applicable; hold over from MISO formula, will be removed with Sec 205
Revenues from service provided by LG&E Energy	0	0	0	to Page 1 of 5, L. 5	Contract demand here is the load with IMEA and IMPA. Per the contract with the partners, we do not charge for transmission so there is no revenue to record on this line.

12 CP Data, requirements service:	Form 1, p. 400, col. (e)	KU	LGE	Combined	
Jan	times 1,000	4,860,000	1,973,000	6,833,000	
Feb		5,112,000	1,967,000	7,079,000	
Mar		4,261,000	1,712,000	5,973,000	
Apr		2,716,000	1,524,000	4,240,000	
May		3,284,000	2,023,000	5,307,000	
Jun		3,790,000	2,472,000	6,262,000	
Jul		3,807,000	2,585,000	6,392,000	
Aug		3,724,000	2,484,000	6,208,000	
Sep		3,756,000	2,443,000	6,199,000	
Oct		3,005,000	1,797,000	4,802,000	
Nov		3,445,000	1,570,000	5,015,000	
Dec		3,456,000	1,570,000	5,026,000	
Average		3,768,000	2,010,000	5,778,000	to Page 1 of 5, L. 8
			check total-NITS	ok	
			check total-PTP	ok	

12 CP Data, firm bundled sales:	Form 1, p. 311, col. (g)	KU	LGE	Combined		
Jan	when p. 310, col (b)	0	0	0		If any, see "Power Transaction Schedule(s)" in applicable Form B
Feb	contains the following:	0	0	0		
Mar	LF, LU, IF, IU	0	0	0		
Apr	times 1,000	0	0	0		
May		0	0	0		
Jun		0	0	0		
Jul		0	0	0		
Aug		0	0	0		
Sep		0	0	0		
Oct		0	0	0		
Nov		0	0	0		
Dec		0	0	0		
Total		0	0	0	to Page 1 of 5, L. 9	
			check total-NITS	ok		
			check total-PTP	ok		

12 CP Data, other network load:	Form 1, p. 400, col. (f) + col. (h)	KU-col F	KU-Col h	LGE-Col F	Combined	
Jan	times 1,000	548,000	0	254,000	802,000	
Feb	LG&E col (h) = 0 for 2015	566,000	0	262,000	828,000	
Mar		485,000	0	225,000	710,000	
Apr		281,000	0	130,000	411,000	
May		400,000	0	186,000	586,000	
Jun		525,000	0	243,000	768,000	
Jul		490,000	0	233,000	723,000	
Aug		548,000	0	260,000	808,000	
Sep		515,000	0	245,000	760,000	
Oct		315,000	0	151,000	466,000	
Nov		437,000	0	208,000	645,000	
Dec		425,000	0	202,000	627,000	
Average		461,250	0	216,583	678,000	to Page 1 of 5, L. 10
				check total-NITS	ok	
				check total-PTP	ok	

12 CP Data, firm Point to Point:	KU	LGE	Combined	
Jan			0	
Feb			0	
Mar			0	
Apr			0	
May			0	
Jun			0	
Jul			0	
Aug			0	
Sep			0	
Oct			0	
Nov			0	
Dec			0	
Average			0	to Page 1 of 5, L. 11
		check total-NITS	ok	
		check total-PTP	ok	

Firm P-T-P transmission is billed on a reservation basis only; amounts are included below and carried to L. 12 of page 1. Transmission does not track or bill firm contract P-T-P customers for actual flows, and the actual flows are not included in the network transmission peaks included above; therefore, there is no CP data associated with firm P-T-P transmission to include here.

Contract demand, firm Point to Point over one year	Form 1, p. 400, col. (g)	KU	LGE	Combined		
Jan	times 1,000	419,000	191,000	610,000		
Feb		419,000	191,000	610,000		
Mar		419,000	191,000	610,000		
Apr		419,000	191,000	610,000		
May		419,000	191,000	610,000		
Jun		419,000	191,000	610,000		
Jul		415,000	194,000	609,000		
Aug		415,000	194,000	609,000		
Sep		415,000	194,000	609,000		
Oct		415,000	194,000	609,000		
Nov		415,000	194,000	609,000		
Dec		415,000	194,000	609,000		
Average		417,000	192,500			
OMU reservations for Long Term PTP				609,500	to Page 1 of 5, L. 12	Provided by Transmission Policy & Tariffs; see workpapers from F Rubio -- OMU reservations included in PTP on page 400
			check total-NITS	ok		
			check total-PTP	ok		

Amounts on Ls. 13 & 14 of page 1 of 5 are provided by Transmission Policy and Rates (Fernando Rubio)

		KU	LGE	Combined		
CBM Capacity withheld from P-T-P Customers		check total-PTP	ok	166,667	to PTP Pg 1 of 5, L. 13	Applicable to PTP only; capacity benefit margin provided by F Rubio, Transmission Policy and Tariffs
Contract demand -- service provided at discount		check total-PTP	ok	427,000	to Page 1 of 5, L. 14	Provided by Transmisison Policy & Tariffs; includes IMEA/IMPA transmission to BAA border per contract and OMU MISO LT PTP reservation due to depancaking

Page 2 of 5

GROSS PLANT IN SERVICE

		KU	LGE	Combined		
Intangible	P.205, L.5, Col.(g)	92,355,301	2,240	92,357,541	to Page 2 of 5, L. 4, col.3	
Production	P.205, L.46, Col.(g)	6,074,705,324	3,205,686,729	9,280,392,053	to Page 2 of 5, L. 1, col.3	
Transmission	P.207, L.58, Col.(g)	807,382,026	382,269,319	1,189,651,345	to Page 2 of 5, L. 2, col.3	
Distribution	P.207, L.75, Col.(g)	1,662,186,831	1,232,856,010	2,895,042,841	to Page 2 of 5, L. 3, col.3	LGE balance, per Form 1 page 356.1 (excludes all 107)
General	P.207, L.99, Col.(g)	177,718,823	17,651,756	195,370,579	to Page 2 of 5, L. 4, col.3	Electric Allocation Ratio
Common	P.356.1, electric only	N/A	186,160,468	186,160,468	to Page 2 of 5, L. 5, col.3	
		total Gross Plant		13,838,974,827		
			check total-NITS	ok		
			check total-PTP	ok		

	101 & 106
LGE balance, per Form 1 page 356.1 (excludes all 107)	265,943,525
Electric Allocation Ratio	70%
	186,160,468

ACCUMULATED DEPRECIATION

		KU	LGE	Combined	
Intangible	P.200, L.21, Col.(c)	49,298,610	0	49,298,610	to Page 2 of 5, L. 10, col.3
Production, Steam	P.219, L.20, Col.(c)	1,556,772,299	893,300,630	2,450,072,929	to Page 2 of 5, L. 7, col.3
Production, Hydro	P.219, L.22, Col.(c)	8,172,349	5,220,509	13,392,857	to Page 2 of 5, L. 7, col.3
Production, Other	P.219, L.24, Col.(c)	237,816,024	103,097,335	340,913,359	to Page 2 of 5, L. 7, col.3
Transmission	P.219, L.25, Col.(c)	333,231,626	147,437,907	480,669,533	to Page 2 of 5, L. 8, col.3
Distribution	P.219, L.26, Col.(c)	632,116,290	466,285,935	1,098,402,225	to Page 2 of 5, L. 9, col.3
General	P.219, L.28, Col.(c)	55,183,009	7,788,328	62,971,336	to Page 2 of 5, L. 10, col.3
Common	P.356.1, electric only	N/A	104,974,058	104,974,058	to Page 2 of 5, L. 11, col.3
		Total Accumulated Reserve		4,600,694,908	
			check total-NITS	ok	
			check total-PTP	ok	

	Accumulated Reserve per Form 1, Pages 200 col. (c), 219 col. (c), & 356.1 KU	LGE	Accumulated Reserve for Depreciation Adjustment KU	LGE
Intangible	44,427,523	0	(4,871,087)	
Steam Prod	1,515,970,573	842,929,463	(40,801,726)	(50,371,167)
Hydro Prod	10,701,471	8,761,689	2,529,122	3,541,180
Other Prod	248,160,618	107,168,895	10,344,594	4,071,560
Transmission	332,446,842	147,408,544	(784,784)	(29,363)
Distribution	638,252,808	475,589,914	6,136,518	9,303,979
General	59,892,154	7,357,244	4,709,145	(431,084)
Common	N/A	96,876,366		(8,097,692)

ADJUSTMENTS TO RATE BASE (Note F)

		KU	LGE	Combined		
Account No. 281	P.273, L.8, Col.(k)	0	0	0	to Page 2 of 5, L. 19, col.3	
Account No. 282	P.275, L.2, Col.(k)	1,272,308,390	738,214,075	2,010,522,465	to Page 2 of 5, L. 20, col.3	
Account No. 283	P.277, L.9, Col.(k)	146,850,085	154,021,334			
Acct. 283 Other (w. PA)	P.277, L.8, Col.(k)	19,581,644	36,169,661			
Acct. 283 Other (w.o. PA)	Footnote for L.8, Col.(k)	5,049,395	10,151,221			use beginning balance, 'Total Without Purchase Accounting"
Net Included Account 283		132,317,836	128,002,894	260,320,730	to Page 2 of 5, L. 21, col.3	
Account No. 190	P.234, L.8, Col.(c)	372,206,512	244,937,160			
Acct. 190 Other (w PA)	P.234, L.7, Col.(c)	31,995,746	41,839,523			
Acct. 190 Other (w.o. PA)	Notes Detail for L.7, electric	17,319,755	16,312,969			use beginning balance, 'Total Without Purchase Accounting"
Net Included Account 190		357,530,521	219,410,606	576,941,127	to Page 2 of 5, L. 22, col.3	
Account No. 255, KU Transmission only	P.267, L.8, Col.(h)	0	N/A	0	to Page 2 of 5, L. 23, col.3	KU ITC balance is an adjustment to rate base for transmission related projects only; outstanding balances are for generation and therefore not included.
Transmission ARO	P.207, L.57, Col.(g)	413,450	218,085	631,535		
Transmission Reserve	Plant reports, P2 REG (KU), P11 (LGE)	43,701	24,596	68,298		
				563,237	to Page 2 of 5, L. 26, col.3 (enter negative)	
Common ARO (electric only)	P.356.1, acct 399 (LGE only)	N/A	0	0		multiply the total balance in account 399 times the electric only allocation ratio
Common Reserve	Plant reports, P5 REG (LGE only)	N/A	0	0		multiply the total balance in account 399 times the electric only allocation ratio
				0	to Page 2 of 5, L. 27, col.3 (enter negative)	
Network Upgrade assets-rate base adjustment						
Ending Balance, previous year				2,118,536		copy prev yr end bal to beg, multiply by calculated depreciation rate in I153
Adjustment for depreciation expense				95,728		
Net Book Network Upgrade Assets				2,022,808		
Assets Added During the year				0		Provided by Transmission if applicable. Represents costs for required network upgrades required in response to a
Ending Balance, current year				2,022,808	to Page 2 of 5, L. 24	request for transmission service that are deemed beneficial to entire network system.
LSE Direct Assign assets-rate base adjustment						
Ending Balance, previous year				8,056,329		
Adjustment for depreciation expense				364,033		depreciation expense:
Net Book LSE Direct Assignment Assets				7,692,296		4.519% 5%
Assets Added During the year				0		Provided by Transmission if applicable. confirm links to transmission plant and book depreciation expense in O159:O160
Ending Balance, current year				7,692,296	to Page 2 of 5, L. 25	copy prev yr end bal to beg, multiply by calculated depreciation rate in I161
Land Held for Future Use	P.214, L.various, Col.(d)	0	0	0	to Page 2 of 5, L. 25, col.3	Only include amounts associated with transmission projects (confirmed by reviewing Plant Report Pg 26 REG (LGE) and Pg 13 REG (KU)
		Total Adjustments		(1,704,180,409)		
			check total-NITS	ok		
			check total-PTP	ok		
Transmission	P.227, L.8, Col.(c)	5,816,467	3,003,481			
Stores Expense Undistributed	P.227, L.16, Col.(c)	9,371,630	5,546,728			
		1,323,592	528,269			
		7,140,059	3,531,750	10,671,809	to Page 2 of 5, L. 31, col.3	
			check total-NITS	ok		
			check total-PTP	ok		
Total Account 154	P.227, L.12, Col.(c)	41,183,222	31,536,000	72,719,222		
	Transmission Ratio	14%	10%			
Prepayments (acct. 165)	P.111, L.57, Col.(c)	7,513,311	6,472,537	13,985,848	to Page 2 of 5, L. 28, col.3	
			check total-NITS	ok		
			check total-PTP	ok		

	KU	LGE	Combined
XM plnt	333,231,626	147,437,907	480,669,533
XM depr	14,686,806	7,032,720	21,719,525

Page 3 of 5

O&M

		KU	LGE	Combined		
Transmission	Page 321, L.112, Col.(b)	31,782,982	14,487,246			Sum of accounts 560-573. Do not include Regional Market Expense, account 575
Less Regulatory Assets:						KU and LG&E have three regulatory assets that are amortized to transmission operating expense;
EKPC, amortized to retail				Amortization complete February 2014		these regulatory assets are approved for rate recovery from retail customers only. The annual
2008 Wind storm amortized to retail only -- distribution only, no transmission impact						amortization must be removed from transmission expense until FERC approves rate recovery.
2009 Ice storm amortized to retail only		76,392	3,482	Amortization until July 2020		Annual amortization amount is provided by Regulatory Accounting and Reporting -- Eric Raible
Total Included Transmission expense		31,706,590	14,483,764	46,190,355	to Page 3 of 5, L. 1, col.3	R&D charged to 930, per page 353:
Less Account 565	Page 321, L.96, Col.(b)	3,381,568	792,961	4,174,529	to Page 3 of 5, L. 2, col.3	
A&G	Page 323, L.197, Col.(b)	120,848,660	84,250,434	205,099,094	to Page 3 of 5, L. 3, col.3	
FERC Annual Fees	Page 351, L.2, Col.(h)	406,748	350,592	757,340	to Page 3 of 5, L. 4, col.3	
EPRI & Reg. Comm. Exp	Page 353, Acct 930, Col.(f)	2,705,097	1,568,345			Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety
Non-safety Ad.	Page 323, L.191, Col.(b)	118,945	116,028			related advertising included in Account 930.1. use total charged to Att O exp accts
Reg Comm Expenses	Page 351, L.46, Col.(h)	1,665,507	1,209,879			
Reg Comm Expenses-Audit	Page 351, L.13 KU,L.12 LGE, Col.(h)	47,507	30,527			FERC audit expenses are recoverable through the transmission revenue requirement and are included in the total entered in C&D179
Reg Comm Expenses-Proj 289	Page 351, L.3, Col.(h) LGE only	0	188,645			
		4,035,294	2,324,488	6,359,782	to Page 3 of 5, L. 5, col.3	FERC annual fees removed because they are separately reported on Line 4; FERC audit removed b/c they are includable in revenue requirement
Plus Transmission Related Reg. Comm. Exp. (Note I)	Page 351 (h) related to transmission only	231,846	213,861	445,707	to Page 3 of 5, L. 6, col.3	Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
Common	Page 356.1	N/A	0	0	to Page 3 of 5, L. 7, col.3	Common Plant related O&M is not maintained separately, but is included in accounts as noted on page 356
Transmission Lease Payments		0	0	0	to Page 3 of 5, L. 8, col.3	will be notified by Transmission Policy and Tariffs
		Total Includable O&M		240,443,505		

KU		LGE	
2,421,324	35,310	1,373,412	18,190
25,448	9,280	13,703	7,760
13,795		97,560	
102,440		52,500	
97,500		5,220	

		KU	LGE	Total	
			check total-NITS	ok	
			check total-PTP	ok	
DEPRECIATION EXPENSE					
Transmission	Page 336, L.7, Col.(f)	14,686,806	7,032,720	21,719,525	to Page 3 of 5, L. 10, col.3
General	Page 336, L.10, Col.(f)	9,534,030	798,626		
Intangible	Page 336, L.1, Col.(f)	12,976,037	0		
		22,510,067	798,626	23,308,693	to Page 3 of 5, L. 11, col.3
Common	Page 336, L.11, Col.(f)	N/A	19,221,540	19,221,540	to Page 3 of 5, L. 12, col.3
Transmission ARO	Page 336, L.7, Col.(c)	0	0	0	to Page 3 of 5, L. 10, col.3
Common ARO	Page 336, L.11, Col.(c)	N/A	0	0	to Page 3 of 5, L. 12, col.3 input accrual amount from LG&E utility report page 2 FIN, and multiply by the electric ratio from page 2 of 5
		Net Includable Depreciation Expense		64,249,758	
			check total-NITS	ok	
			check total-PTP	ok	

Reference: Depreciation Expense per Form 1, Page 336, Col.(f)	KU	LGE	Depreciation Expense Adjustment KU	Depreciation Expense Adjustment LGE
Transmission	14,413,824	7,018,552	(272,982)	(14,168)
General	11,533,606	856,655	1,999,576	58,029
Intangible	10,864,312		(2,111,725)	
Common		15,838,253		(3,383,287)

TAXES OTHER THAN INCOME TAXES (Note J)

Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

Line numbers can differ between the two Companies, so use the "Kind of Tax" entry in Col.(a), page 262 to select the correct amount on page 263 for the input (applies to payroll taxes, highway & vehicle taxes, and plant related taxes

		KU	LGE	Total	
LABOR RELATED					
Payroll	263.i				
FICA	Page 262-3, L.3, Col.(i)	9,348,184	6,749,475		
Unemployment Insurance	Page 262-3, L.11 (K), L.12 (L), Col.(i)	222,990	159,007		
Local: Occupational	Page 262-3, L.14 (L), Col.(i)	N/A	46,289		
Total Payroll Taxes		9,571,174	6,954,771	16,525,945	to Page 3 of 5, L. 14, col.3
Highway and vehicle	Page 262-3, L.15 (K), L.14 (L), Col.(i)	62,321	28,611	90,932	to Page 3 of 5, L. 15, col.3 See note above
PLANT RELATED					
Property	Page 262-3, L.14 (K), L.17 (L), Col.(i)	25,680,955	19,235,773	44,916,728	to Page 3 of 5, L. 17, col.3 See note above
Gross Receipts	Page 262-3, Col.(i)	N/A	N/A	0	
Other	Page 262-3, Col.(i)				
Public Service Commission	Page 262-3, L.7, Col.(i)	2,951,355	2,121,000		
6% Use tax (KY)	Page 262-3, L.8, Col.(i)	34,857	0		
Miscellaneous	Page 262-3, L.15 (K), Col.(i)	508	N/A		
Total Other Taxes		2,986,720	2,121,000	5,107,720	to Page 3 of 5, L. 18, col.3 See note above
		Total Other Taxes		66,641,325	
			check total-NITS	ok	
			check total-PTP	ok	

INCOME TAX INPUTS AND CALCULATIONS

FIT =	35.00%		to Page 5 of 5, Note K
SIT=	6.00%	(State Income Tax Rate or Composite SIT)	to Page 5 of 5, Note K
p =	0.00%	(percent of federal income tax deductible for state purposes)	to Page 5 of 5, Note K

		KU	LGE	
income-fed	Page 263, L.2, Col.(i)	-19,453,420	-12,314,375	
income state	Page 263, L.6, Col.(i)	1,153,593	1,867,677	
check total on taxes		20,001,343	17,893,457	agrees to total on page 263, column i

		KU	LGE	Total	
Account 255, amortization of ITC	Page 266, L.8, Col.(f)	0	0	0	to Page 3 of 5, L. 24, col.3, negative KU ITC amortization is below the line in Other Income & Deductions; LGE ITC is production related & excluded from XM

Page 4 of 5

Ancillary Charges Per Schedule 1:		KU	LGE	Total	
(561)					
(561.1)	Page 321, L.85, Col.(b)	509,431	265,644	775,075	to Sch 1, L.2
(561.2)	Page 321, L.86, Col.(b)	1,989,765	1,048,600	3,038,365	to Sch 1, L.3
(561.3)	Page 321, L.87, Col.(b)	708,930	365,206	1,074,136	to Sch 1, L.4
(561.4)	Page 321, L.88, Col.(b)	0	0	0	to Sch 1, L.5
(561.5)	Page 321, L.89, Col.(b)	918,887	460,299	1,379,186	to Sch 1, L.6
(561.6)	Page 321, L.90, Col.(b)	9,085	-936	8,149	to Sch 1, L.7
(561.7)	Page 321, L.91, Col.(b)	0	0	0	to Sch 1, L.8
(561.8)	Page 321, L.92, Col.(b)	0	0	0	to Sch 1, L.9
Total		4,136,098	2,138,813	6,274,911	to page 4 of 5, L. 7 Ancillary services are included in the formula for Schedule 1 and must be removed in Attachment O
			check total-NITS	ok	
			check total-PTP	ok	

Wages and Salaries		KU	LGE	Total	
Production	Page 354, L.20, Col.(b)	44,284,843	35,088,724	79,373,567	to page 4 of 5, L. 12
Transmission	Page 354, L.21, Col.(b)	5,940,240	3,256,660	9,196,900	to page 4 of 5, L. 13
Distribution	Page 354, L.23, Col.(b)	16,009,783	10,793,951	26,803,734	to page 4 of 5, L. 14
Other					
Customer Accounts	Page 354, L.24, Col.(b)	12,088,541	4,111,598		
Customer Service	Page 354, L.25, Col.(b)	1,086,053	744,996		
Sales	Page 354, L.26, Col.(b)	0	0		
		13,174,594	4,856,594	18,031,188	to page 4 of 5, L. 15
		Total Wages and Salaries		133,405,389	
			check total-NITS	ok	
			check total-PTP	ok	

COMMON PLANT ALLOCATOR (CE) (Note O)		KU	LGE	Total	
Electric	Page 200, L.3, Col.(c)	7,232,591,744	3,748,677,590	10,981,269,334	to page 4 of 5, L. 17
Gas	Page 201, L.3, Col.(d)	0	966,619,554	966,619,554	to page 4 of 5, L. 18
Water	Page 201, L.3, Col.(e)	0	0	0	to page 4 of 5, L. 19
		Total Plant		11,947,888,888	
			check total-NITS	ok	
			check total-PTP	ok	

RETURN INPUTS		KU	LGE	Total	
Long Term Interest					
Account 427	Page 117, L.62, Col.(c)	75,653,843	50,809,850		
Purchase Accounting Adjustments					
Acct 427 (PA)	Page 117, L.62, Col.(c)	75,653,843	50,809,850		
Acct 427 (w.o. PA)	Footnote to line 62	75,807,104	50,718,552		
Account 428	Page 117, L.63, Col.(c)	2,958,222	2,470,268		
Account 428.1	Page 117, L.64, Col.(c)	683,508	1,167,401		
Account 429	Page 117, L.65, Col.(c)	0	0		
Account 429.1	Page 117, L.66, Col.(c)	0	0		
Account 430	Page 117, L.67, Col.(c)	1,170	5,661		
		79,450,004	54,361,882	133,811,886	to page 4 of 5, L. 21
			check total-NITS	ok	
			check total-PTP	ok	
Preferred Dividends	Page 118, L.29, Col.(c)	0	0	0	to page 4 of 5, L. 22
Proprietary Capital	Page 112, L.16, Col.(c)	3,286,531,337	2,330,399,677	5,616,931,014	
Purchase Accounting Adjustments					
Other Paid In Capital (PA)	Page 112, L.7, Col.(c)	2,596,446,834	1,611,167,368	4,207,614,202	
Other Paid In Capital (w.o. PA)	Footnote to line 7	563,858,083	417,081,499	980,939,582	

Retained Earnings (PA)	Page 112, L.11, Col.(c)	382,553,214	294,897,774	677,450,988		
Retained Earnings (w.o. PA)	Footnote to line 11	1,809,303,187	1,098,854,463	2,908,157,650		
Acct 216.1 (PA)	Page 112, L.12, Col.(c)	0	0	0		
Acct. 216.1 (w.o. PA)	Footnote to L.12	0	0	0		
Acct 219 (PA)	Page 112, L.15, Col.(c)	-287,400	0	(287,400)		
Acct 219 (w.o. PA)	Footnote to L.15	-1,627,215	0	(1,627,215)		
Proprietary Capital without Purchase Accounting		2,679,352,744	1,940,270,497	4,619,623,241	to page 4 of 5, L. 23	
			check total-NITS	ok		
			check total-PTP	ok		
ADJUSTMENTS TO CAPITALIZATION						
Unappropriated Undistributed Earnings	Page 112, L.12, Col.(c)	0	0			
Accum. OCI, Acct. 219	Page 112, L.15, Col.(c)	-287,400	0			
Purchase Accounting Adjustments						
Acct 216.1 (PA)	Page 112, L.12, Col.(c)	0	0			
Other Paid In Capital (w.o. PA)	Footnote to L.12	0	0			
Acct 219 (PA)	Page 112, L.15, Col.(c)	-287,400	0			
Acct 219 (w.o. PA)	Footnote to L.15	-1,627,215	0			
Unappropriated Undistributed Earnings w/o PA		(1,627,215)	0	(1,627,215)	to page 4 of 5, L. 25	
			check total-NITS	ok		
			check total-PTP	ok		
LONG TERM DEBT						
Total Long Term Debt	Page 112, L.24, Col.(c)	2,341,500,118	1,653,138,914			
Purchase Accounting Adjustments						
Acct 224 (PA)	Page 112, L.21, Col.(c)	369,516	-1,590,554			
Acct 224 (w.o. PA)	Footnote to L.21	0	0			
Total Long Term Debt		2,341,130,602	1,654,729,468	3,995,860,070	to page 4 of 5, L. 27	
			check total-NITS	ok		
			check total-PTP	ok		
Return on Equity				0.1088	to page 4 of 5, L. 30	Set by FERC Order; only change with authorization to do so.
Account 456 -- Other Electric Revenues						
Line 35a-Transmission Charges for all transmission transactions:						
Total Transmission Charges	Page 330, Col.(n)	18,710,777	8,643,621	27,354,398	to page 4 of 5, L. 35	
Page 328, Col.(d) contains FNO	Page 330, L.1, Col.(n)		2,129,215	ok	check total-NITS	
	Page 330, L.2, Col.(n)	4,672,882		ok	check total-PTP	
	Page 330, L.7, Col.(n)	1,765,584				
	Page 330, L.10, Col.(n)	1,563,583				
	Page 330, L.15, Col.(n)		27,196			
	Page 330, L.17, Col.(n)	899,987				
	Page 330, L.18, Col.(n)		869,518			
	Page 330, L.21, Col.(n)		788,903			
	Page 330, L.24, Col.(n)	123,061				
	Page 330, L.27, Col.(n)	9,700				
	Page 330, L.28, Col.(n)		55,976			
	Page 330, L.30, Col.(n)	59,673				
	Page 330, L.31, Col.(n)		4,824			
	Page 330.1, L.9, Col.(n)		409,899			
	Page 330.1, L.13, Col.(n)	218,662				
	Page 330.1, L.15, Col.(n)	419,768				
	Page 330.1, L.17, Col.(n)	19,504	100,119			
	Page 330.1, L.19, Col.(n)	9,382	192,418			
	Page 330.1, L.21, Col.(n)	303,927	8,952			
	Page 330.1, L.23, Col.(n)	193,943	4,205			
	Page 330.1, L.25, Col.(n)	42,808	139,026			
	Page 330.1, L.26, Col.(n)	74,813				
	Page 330.1, L.27, Col.(n)		88,839			
	Page 330.1, L.28, Col.(n)	1,531,537				
	Page 330.1, L.29, Col.(n)		19,622			
	Page 330.1, L.30, Col.(n)	601,585				
	Page 330.1, L.31, Col.(n)		701,533			
	Page 330.1, L.32, Col.(n)	431,736				
	Page 330.1, L.33, Col.(n)		276,138			
	Page 330.1, L.34, Col.(n)	148,257				
	Page 330.2, L.1, Col.(n)		197,694			
	Page 330.2, L.2, Col.(n)	64,152				
	Page 330.2, L.3, Col.(n)		67,842			
	Page 330.2, L.5, Col.(n)		29,427			
Page 328, Col.(d) contains OLF	Page 330, L.6, Col.(n)		0			
	Page 330, L.8, Col.(n)		0			
Page 328, Col.(d) contains FNS	no FNS codes for either company					
Page 328, Col.(d) contains AD	Page 330, L.1, Col.(n)	145,043				
	Page 330, L.2, Col.(n)		-12,128			
	Page 330, L.3, Col.(n)	-26,626				
	Page 330, L.4, Col.(n)		-2,470			
	Page 330, L.5, Col.(n)	-5,553	-6,331			
	Page 330, L.6, Col.(n)	-13,767				
	Page 330, L.8, Col.(n)	30,046				
	Page 330, L.9, Col.(n)	-3,762				
	Page 330, L.10, Col.(n)		-83			
	Page 330, L.11, Col.(n)	39,693				
	Page 330, L.12, Col.(n)		-1,197			
	Page 330, L.13, Col.(n)	44,170				
	Page 330, L.14, Col.(n)	-8,640				
	Page 330, L.16, Col.(n)	4,852	-10			
	Page 330, L.17, Col.(n)		-62			
	Page 330, L.18, Col.(n)	-9,067				
	Page 330, L.19, Col.(n)	-20,008	13,367			
	Page 330, L.20, Col.(n)	21,490	-1,754			
	Page 330, L.22, Col.(n)	6	17,659			
	Page 330, L.23, Col.(n)	-786	-4,027			
	Page 330, L.25, Col.(n)	824	19,650			
	Page 330, L.26, Col.(n)	-1,340				
	Page 330, L.27, Col.(n)		2,159			
	Page 330, L.29, Col.(n)	-27	-596			
	Page 330, L.30, Col.(n)		361			
	Page 330, L.31, Col.(n)	-134				
	Page 330, L.32, Col.(n)	-22				
	Page 330, L.33, Col.(n)		-12			
	Page 330, L.34, Col.(n)	-2,598				

	Page 330.1, L.2, Col.(n)		1			
	Page 330.1, L.3, Col.(n)		-4			
	Page 330.1, L.4, Col.(n)		555			
	Page 330.1, L.5, Col.(n)	-9				
	Page 330.1, L.6, Col.(n)	1	17,137			
	Page 330.1, L.8, Col.(n)	38,522	32			
	Page 330.1, L.10, Col.(n)	72	-2,021			
	Page 330.1, L.11, Col.(n)	-185	-794			
	Page 330.1, L.12, Col.(n)	1,247	1,365			
	Page 330.1, L.14, Col.(n)	1,050	3			
	Page 330.1, L.15, Col.(n)		-116			
	Page 330.1, L.16, Col.(n)	2,376	66,212			
	Page 330.1, L.18, Col.(n)	-247	467			
	Page 330.1, L.20, Col.(n)	96	1,057			
	Page 330.1, L.22, Col.(n)	1,143	-110			
	Page 330.1, L.24, Col.(n)	1,125	43			
	Page 330.1, L.26, Col.(n)		508			
	Page 330.1, L.27, Col.(n)	174				
	Page 330.1, L.28, Col.(n)		501			
	Page 330.1, L.29, Col.(n)	7,504				
	Page 330.1, L.30, Col.(n)		77			
	Page 330.1, L.31, Col.(n)	41,845				
	Page 330.1, L.32, Col.(n)		3,338			
	Page 330.1, L.33, Col.(n)	2,543				
	Page 330.1, L.34, Col.(n)		18,617			
	Page 330.2, L.1, Col.(n)	1,281				
	Page 330.2, L.2, Col.(n)		1,131			
	Page 330.2, L.3, Col.(n)	644				
	Page 330.2, L.4, Col.(n)		570			
	Page 330.2, L.6, Col.(n)		286			
Page 328, Col.(d) contains LFP	Page 330, L.7, Col.(n)		0			
	Page 330, L.9, Col.(n)		0			
	Page 330, L.12, Col.(n)	3,459,423				
	Page 330, L.14, Col.(n)		151,708			
	Page 330, L.24, Col.(n)		1,577,737			
	Page 330.1, L.2, Col.(n)	332,642				
Excluded Charges		1,471,192	669,449		2,140,641	agree to page 4 of 5, L. 37
		17,239,585	7,974,172		25,213,757	to Page 4 of 5, L. 36
				ok		check total-NITS
				ok		check total-PTP

Schedule 1	KU	LG&E			
Expenses					Ancillary service expenses are itemized above for removal from Attachment O.
Revenue					
Scheduling System Control & Dispatch	570,954	292,550	863,504	To Sch. 1, Line 11	All Sch. 1 charges except the cost of depancaking for OMU and KMPA; provided by F. Rubio, Transmission
Revenue from Network & Long Term	(530,084)	(271,574)	(801,658)	To Sch. 1, Line 12	Sch. 1 charges for network, long term firm, and firm other; provided by F. Rubio, Transmission
Short-Term and Non-Firm Revenue	40,870	20,976	61,846	To Sch. 1, Line 13	

Kentucky Utilities Company
TOTAL 101 & 106
Plant in Service
12/31/2015

Source: December 2015 Kentucky Utilities Company Monthly Plant Report provided by Property Accounting
Tab: VA_PIS NBV P9 (REG) -- Electric Transmission only starting on row 46 of support file

Electric Transmission

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance	Ending Balance Per Plant Report	Check
E350.10-Land Rights	2,118,631.22	-	-	-	-	2,118,631.22	2,118,631.22	-
E350.20-Land	45,700.50	-	-	-	-	45,700.50	45,700.50	-
E352.10-Struct & Imp-Non Sys Contro	1,618,031.92	-	(111.76)	-	(111.76)	1,617,920.16	1,617,920.16	-
E353.10-Station Equipment - Non Sys	20,730,624.78	965,189.57	(116,717.44)	291,019.11	1,139,491.24	21,870,116.02	21,870,116.02	-
E354.00-Towers and Fixtures	7,181,081.30	-	-	-	-	7,181,081.30	7,181,081.30	-
E355.00-Poles and Fixtures	9,932,648.67	1,309,887.16	(28,951.64)	-	1,280,935.52	11,213,584.19	11,213,584.19	-
E356.00-OH Conductors and Devices	16,964,093.09	(133,733.38)	(4,168.16)	-	(137,901.54)	16,826,191.55	16,826,191.55	-
E357.00-Underground Conduit	-	-	-	-	-	-	-	-
E358.00-Underground Conductors a	-	-	-	-	-	-	-	-
Total	58,590,811.48	2,141,343.35	(149,949.00)	291,019.11	2,282,413.46	60,873,224.94	60,873,224.94	-

Source: VA 500 KV Line - Dec 2015.xlsx provided by Property Accounting
Notes: Source spreadsheet provided by Property Accounting for the annual cost separation study. If any entries in the Date column are for current year, include dollar amounts on appropriate acct row in the Additions column; otherwise, check for change in balance due to retirements. Previous year ending balance is transferred to current year beginning balance, additions and retirements are entered as appropriate in columns, and ending balance is updated automatically.

Electric Transmission -- 500kV Transmission Line Located in Virginia, serving Kentucky

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance		Check
E350.10-Land Rights	280,370.75	-	-	-	-	280,370.75		
E350.20-Land	-	-	-	-	-	-		
E352.10-Struct & Imp-Non Sys Contro	-	-	-	-	-	-		
E353.10-Station Equipment - Non Sys	-	-	-	-	-	-		
E354.00-Towers and Fixtures	4,769,322.87	-	-	-	-	4,769,322.87		
E355.00-Poles and Fixtures	51,357.98	-	-	-	-	51,357.98		
E356.00-OH Conductors and Devices	3,129,377.81	-	-	-	-	3,129,377.81		
E357.00-Underground Conduit	-	-	-	-	-	-		
E358.00-Underground Conductors a	-	-	-	-	-	-		
Total	8,230,429.41	-	-	-	-	8,230,429.41	8,230,429.41	-

Notes: VA transmission plant total from row 59 below is linked to Page 4 of 5, line 2, and a transmission plant allocator is calculated to appropriately remove from all formula rate components any costs related to VA transmission facilities from total transmission on Page 2 of 5, line 8.

Electric Transmission -- Virginia Balances excluded from OATT formula rate

	Beginning Balance	Additions	Retirements	Transfers/ Adjustments	Net Additions	Ending Balance
E350.10-Land Rights	1,838,260.47	-	-	-	-	1,838,260.47
E350.20-Land	45,700.50	-	-	-	-	45,700.50
E352.10-Struct & Imp-Non Sys Contro	1,618,031.92	-	(111.76)	-	(111.76)	1,617,920.16
E353.10-Station Equipment - Non Sys	20,730,624.78	965,189.57	(116,717.44)	291,019.11	1,139,491.24	21,870,116.02
E354.00-Towers and Fixtures	2,411,758.43	-	-	-	-	2,411,758.43
E355.00-Poles and Fixtures	9,881,290.69	1,309,887.16	(28,951.64)	-	1,280,935.52	11,162,226.21
E356.00-OH Conductors and Devices	13,834,715.28	(133,733.38)	(4,168.16)	-	(137,901.54)	13,696,813.74
E357.00-Underground Conduit	-	-	-	-	-	-
E358.00-Underground Conductors a	-	-	-	-	-	-
Total	50,360,382.07	2,141,343.35	(149,949.00)	291,019.11	2,282,413.46	52,642,795.53
					check total-NITS	ok
					check total-PTP	ok

ATTACHMENT O
RATE FORMULA FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015
Page 1 of 5

LG&E and KU

Line No.				Total		Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	Pg 3 of 5, L. 29					$	139,666,779
	REVENUE CREDITS	Note T		Total		Allocator		
2	Account No. 454	Pg 4 of 5, L. 35	$	-	TP	0.95575	$	0
3	Account No. 456	Pg 4 of 5, L. 38		2,140,641	TP	0.95575		2,045,918
4	Revenues from Grandfathered Interzonal Transactions			0	TP	0.95575		0
5	Revenues from service provided by LG&E and KU at a discount			0	TP	0.95575		0
6	TOTAL REVENUE CREDITS	Sum of Ls. 2-5					$	2,045,918
7	NET REVENUE REQUIREMENT	L.1 - L.6					$	137,430,710
	DIVISOR							
8	Average of 12 coincident system peaks for requirements (RQ) service (kW)			Note A				5,778,000
9	Plus 12 CP of firm bundled sales over one year not in line 8 (kW)			Note B				-
10	Plus 12 CP of Network Load not in line 8 (kW)			Note C				678,000
11	Less 12 CP of firm P-T-P over one year (enter negative) (kW)			Note D				0
12	Plus Contract Demand of firm P-T-P over one year (kW)							609,500
13	[RESERVED]							0
14	Less Contract Demands from service over one year provided by LG&E and KU at a discount (enter negative) (kW)							(427,000)
15	Divisor (kW)	Sum of Ls. 8-14						6,638,500
16	Annual Cost ($/kW/Yr)	L. 7÷ L. 15	$	20.702				
17	Network Rate ($/kW/Month)	L. 16 ÷ 12	$	1.725				
18	[RESERVED]							
19	[RESERVED]							
20	[RESERVED]							
21	FERC Annual Charge($/MWh)	Note E	$	0.000		Short Term	$	0.000
22			$	0.000		Long Term	$	0.000

ATTACHMENT O
RATE FORMULA FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015

LG&E and KU

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 9,280,392,053	NA		
2	Transmission	207.58.g	1,189,651,345	TP	0.95575	$ 1,137,009,273
3	Distribution	207.75.g	2,895,042,841	NA		
4	General & Intangible	205.5.g & 207.99.g	287,728,120	W/S	0.06589	18,958,406
5	Common	356.1	186,160,468	CE	0.06056	11,273,878
6	TOTAL GROSS PLANT	Sum of Ls. 1 - 5	$ 13,838,974,827	GP =	0.08434	$ 1,167,241,557

	ACCUMULATED DEPRECIATION	Note Y				
7	Production	219.20-24.c	$ 2,804,379,145	NA		
8	Transmission	219.25.c	480,669,533	TP	0.95575	$ 459,399,907
9	Distribution	219.26.c	1,098,402,225	NA		
10	General & Intangible	219.28.c & 200.21.c	112,269,946	W/S	0.06589	7,397,467
11	Common	356.1	104,974,058	CE	0.06056	6,357,229
12	TOTAL ACCUM. DEPRECIATION	Sum of Ls. 7 - 11	$ 4,600,694,908			$ 473,154,603
	NET PLANT IN SERVICE					
13	Production	L.1 - L.7	$ 6,476,012,908			
14	Transmission	L.2 - L.8	708,981,812			$ 677,609,366
15	Distribution	L.3 - L.9	1,796,640,616			
16	General & Intangible	L.4 - L.10	175,458,174			11,560,939
17	Common	L.5 - L.11	81,186,409			4,916,649
18	TOTAL NET PLANT	Sum of Ls. 13 - 17	$ 9,238,279,919	NP =	0.07513	$ 694,086,954
	ADJUSTMENTS TO RATE BASE	Note F				
19	Account No. 281 (enter negative)	273.8.k	$ 0	NA		
20	Account No. 282 (enter negative)	275.2.k	(2,010,522,465)	NP	0.07513	$ (151,050,553)
21	Account No. 283 (enter negative)	277.9.k & Note W	(260,320,730)	NP	0.07513	(19,557,896)
22	Account No. 190	234.8.c & Note W	576,941,127	NP	0.07513	43,345,587
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.07513	0
24	Network Upgrade (enter negative)	Note X	(2,022,808)	TP	0.95575	(1,933,299)
25	LSE Direct Assignment (enter negative)	Note X	(7,692,296)		1.00000	(7,692,296)
26	Transmission Plant ARO -- Net Balance (enter negative)		(563,237)	TP	0.95575	(538,314)
27	Common Plant ARO -- Net Balance (enter negative)		0	CE	0.06056	0
28	TOTAL ADJUSTMENTS	Sum of Ls. 19 - 27	$ (1,704,180,409)			$ (137,426,771)
29	LAND HELD FOR FUTURE USE	214.x.d; Notes G & Z	$ 0	TP	0.95575	$ 0
	WORKING CAPITAL	Note H				
30	CWC	calculated	$ 30,055,438			$ 5,923,462
31	Materials & Supplies	227.8.c & 16.c; Note G	10,671,809	TE	0.82591	8,813,954
32	Prepayments (Account 165)	111.57.c	13,985,848	GP	0.08434	1,179,566
33	TOTAL WORKING CAPITAL	Sum of Ls. 30 - 32	$ 54,713,095			$ 15,916,982
34	Rate Base	Sum of Ls. 18,28,29,33	$ 7,588,812,605			$ 572,577,165

ATTACHMENT O
RATE FORMULA FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015

LG&E and KU

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b; see also Note V	$ 46,190,355	TE	0.82591	$ 38,149,076
2	Less Account 565 (enter negative)	321.96.b	(4,174,529)		1.00000	(4,174,529)
3	A&G	323.197.b	205,099,094	W/S	0.06589	13,513,979
4	Less FERC Annual Fees (enter negative)	351.2.h	(757,340)	W/S	0.06589	(49,901)
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (enter negative)	Note I	(6,359,782)	W/S	0.06589	(419,046)
6	Plus Transmission Related Reg. Comm. Exp.	Note I	445,707	TE	0.82591	368,114
7	Common	356.1	0	CE	0.06056	0
8	Transmission Lease Payments		0		1.00000	0
9	TOTAL O&M	Sum of Ls. 1-8	$ 240,443,505			$ 47,387,693
	DEPRECIATION AND AMORTIZATION EXPENSE	Note Y				
10	Transmission (net of ARO depreciation)	336.7.b	$ 21,719,525	TP	0.95575	$ 20,758,436
11	General and Intangible	336.10.b & 336.1.f	23,308,693	W/S	0.06589	1,535,810
12	Common (net of ARO depreciation)	336.11.b	19,221,540	CE	0.06056	1,164,056
13	TOTAL DEPRECIATION	Sum of Ls. 10-12	$ 64,249,758			$ 23,458,302
	TAXES OTHER THAN INCOME TAXES	Notes J & Z				
	LABOR RELATED					
14	Payroll	263.i	$ 16,525,945	W/S	0.06589	$ 1,088,895
15	Highway and vehicle	263.i	90,932	W/S	0.06589	5,992
16	PLANT RELATED					
17	Property	263.i	44,916,728	GP	0.08434	3,788,277
18	Other	263.i	5,107,720	GP	0.08434	430,785
19	Payments in lieu of taxes		0	GP	0.08434	0
20	TOTAL OTHER TAXES	Sum of Ls. 14-19	$ 66,641,325			$ 5,313,949
	DEVELOPMENT OF INCOME TAXES	Note K				
21	T = 1 - ([(1 - SIT) x (1 - FIT)] ÷ (1 - SIT x FIT x p))		38.90%			
22	CIT = (T ÷ (1 - T)) x (1 - (WCLTD ÷ R)), where:		50.29%			
	WCLTD =	Pg 4 of 5, L. 28	1.55%			
	R =	Pg 4 of 5, L. 31	7.38%			
	FIT, SIT and p	Note K				
23	Income Tax Gross Up Factor: 1 / (1 - T)	T = L. 21	1.63666121			
24	Amortized Investment Tax Credit (enter negative)	266.8.f; see also Note K	0			

25	Income Tax Calculation	L. 22 x L. 28	$ 281,651,343			$ 21,250,640
26	ITC adjustment	L. 23 x L. 24	0	NP	0.07513	0
27	Total Income Taxes	Sum of Ls. 25-26	$ 281,651,343			$ 21,250,640
28	RETURN (rate base times rate of return)	Pg 2 of 5, L.34 x Pg 4 of 5, L. 31	$ 560,054,370			$ 42,256,195
29	REVENUE REQUIREMENT	Sum of Ls. 9,13,20,27,28	$ 1,213,040,301			$ 139,666,779

ATTACHMENT O
RATE FORMULA FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015
Page 4 of 5

LG&E and KU
SUPPORTING CALCULATIONS AND NOTES

Line No.					
	TRANSMISSION PLANT INCLUDED IN LG&E and KU RATES				
1	Total transmission plant	Pg 2 of 5, L.2, C.3		$	1,189,651,345
2	Less transmission plant excluded from LG&E and KU rates	Note M			52,642,796
3	Less transmission plant included in OATT Ancillary Services	Note N			0
4	Transmission plant included in LG&E and KU rates	L. 1 - L.2 - L.3		$	1,137,008,549
5	Percentage of transmission plant included in LG&E and KU Rates	L.4 ÷ L.1	TP=		0.95575
	TRANSMISSION EXPENSES				
6	Total transmission expenses	Pg 3 of 5, L.1, C.3		$	46,190,355
7	Less transmission expenses included in OATT Ancillary Services	Note L			6,274,911
8	Included transmission expenses	L. 6 - L.7		$	39,915,444
9	Percentage of transmission expenses after adjustment	L.8 ÷ L.6			0.86415
10	Percentage of transmission plant included in LG&E and KU Rates	L. 5	TP		0.95575
11	Percentage of transmission expenses included in LG&E and KU Rates	L.9 x L.10	TE=		0.82591

Line No.	WAGE & SALARY ALLOCATOR (W&S)	Form 1 Reference		Total W&S	TP			Allocated W&S			
12	Production	354.20.b	$	79,373,567	0.00		$	0			
13	Transmission	354.21.b		9,196,900	0.95575			8,789,937			
14	Distribution	354.23.b		26,803,734	0.00			0		W&S Allocator	
15	Other	354.24,25,26.b		18,031,188	0.00			0		(Allocated W&S ÷ Total W&S)	
16	Total Wages and Salaries	Sum of Ls. 12-15	$	133,405,389			$	8,789,937	=	0.06589	= W/S

Line No.	COMMON PLANT ALLOCATOR (CE)	Note O		Total Plant					
17	Electric	200.3.c	$	10,981,269,334					
18	Gas	201.3.d		966,619,554					
19	Water	201.3.e		0					
20	Total Plant	Sum of Ls. 17-19	$	11,947,888,888					
21	Electric Plant Ratio	L. 17 ÷ L. 20			0.91910	times W/S (L. 16)	0.06589	0.06056	= CE

Line No.	DEVELOPMENT OF RATE OF RETURN (R)			Total per Form 1
22	Long Term Interest	117.62-67.c; Note W	$	133,811,886
23	Preferred Dividends	118.29.c		0
	Development of Common Stock:			
24	Proprietary Capital	112.16.c	$	4,619,623,241
25	Less Preferred Stock (enter negative)	L.29		0

26	Less Accounts 216.1 & 219 (enter negative)	112.12.c; 112.15.c		(1,627,215)				
27	Total Common Stock	Sum of Ls. 24-26	$	4,617,996,026				
	Weighted Average Cost of Capital:			Total Company	%	Cost Rate (Note P)	Weighted	
28	Long Term Debt	112.18-23.c; Note W	$	3,995,860,070	46.39%	0.0335	0.0155	= WCLTD
29	Preferred Stock	112.3.c		0	0.00%	0.0000	0.0000	
30	Common Stock	L.27		4,617,996,026	53.61%	0.1088	0.0583	
31	Total	Sum of Ls. 28-30	$	8,613,856,096			0.0738	= R

	REVENUE CREDITS				
	ACCOUNT 447 (SALES FOR RESALE)				Load
32	a. Bundled Non-RQ Sales for Resale (kW)		310-311, Note Q		0
33	b. Bundled Sales for Resale included in Divisor on page 1 (kW)		311.x.h; Note Z		0
34	Total (kW)		L. 32-L.33		0
35	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)		Note R	$	0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)	Notes U & Z		
36	a. Transmission charges for all transmission transactions			$	27,354,398
37	b. Transmission charges for all transmission transactions included in Divisor on Page 1				25,213,757
38	Total		L. 36-L.37	$	2,140,641

ATTACHMENT O
RATE FORMULA FOR POINT TO POINT TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015
Page 1 of 5

LG&E and KU

Line No.				Total		Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	Pg 3 of 5, L. 29						$ 139,666,779
	REVENUE CREDITS	Note T		Total		Allocator		
2	Account No. 454	Pg 4 of 5, L. 35	$	-	TP	0.95575		$ 0
3	Account No. 456	Pg 4 of 5, L. 38		2,140,641	TP	0.95575		2,045,918
4	Revenues from Grandfathered Interzonal Transactions			0	TP	0.95575		0
5	Revenues from service provided by LG&E and KU at a discount			0	TP	0.95575		0
6	TOTAL REVENUE CREDITS	Sum of Ls. 2-5						$ 2,045,918
7	NET REVENUE REQUIREMENT	L.1 - L.6						$ 137,430,710
	DIVISOR							
8	Average of 12 coincident system peaks for requirements (RQ) service (kW)				Note A			5,778,000
9	Plus 12 CP of firm bundled sales over one year not in line 8 (kW)				Note B			0
10	Plus 12 CP of Network Load not in line 8 (kW)				Note C			678,000
11	Less 12 CP of firm P-T-P over one year (enter negative) (kW)				Note D			0
12	Plus Contract Demand of firm P-T-P over one year (kW)							609,500
13	Plus CBM Capacity withheld from P-T-P Customers (kW)							166,667
14	Less Contract Demands from service over one year provided by LG&E and KU at a discount (enter negative) (kW)							(427,000)
15	Divisor (kW)	Sum of Ls. 8-14						6,805,167
16	Annual Cost ($/kW/Yr)	L. 7÷ L. 15	$	20.195				
17	P-to-P Rate ($/kW/Month)	L. 16 ÷ 12	$	1.683				
				Peak Rate				Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	L. 16 ÷ 52	$	0.388			L. 16 ÷ 52	$ 0.388
19	Point-To-Point Rate ($/kW/Day)	L. 18 ÷ 5	$	0.078	Capped at weekly rates		L. 18 ÷ 7	$ 0.055
20	Point-To-Point Rate ($/MWh)	L. 19 ÷ 16	$	4.875	Capped at weekly & daily rates		L. 19 ÷ 24	$ 2.292
21	FERC Annual Charge($/MWh)	Note E	$	0.000		Short Term		$ 0.000
22			$	0.000		Long Term		$ 0.000

ATTACHMENT O
RATE FORMULA FOR POINT TO POINT TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015

LG&E and KU

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 9,280,392,053	NA		
2	Transmission	207.58.g	1,189,651,345	TP	0.95575	$ 1,137,009,273
3	Distribution	207.75.g	2,895,042,841	NA		
4	General & Intangible	205.5.g & 207.99.g	287,728,120	W/S	0.06589	18,958,406
5	Common	356.1	186,160,468	CE	0.06056	11,273,878
6	TOTAL GROSS PLANT	Sum of Ls. 1 - 5	$ 13,838,974,827	GP=	0.08434	$ 1,167,241,557

	ACCUMULATED DEPRECIATION	Note Y				
7	Production	219.20-24.c	$ 2,804,379,145	NA		
8	Transmission	219.25.c	480,669,533	TP	0.95575	$ 459,399,907
9	Distribution	219.26.c	1,098,402,225	NA		
10	General & Intangible	219.28.c & 200.21.c	112,269,946	W/S	0.06589	7,397,467
11	Common	356.1	104,974,058	CE	0.06056	6,357,229
12	TOTAL ACCUM. DEPRECIATION	Sum of Ls. 7 - 11	$ 4,600,694,908			$ 473,154,603
	NET PLANT IN SERVICE					
13	Production	L.1 - L.7	$ 6,476,012,908			
14	Transmission	L.2 - L.8	708,981,812			$ 677,609,366
15	Distribution	L.3 - L.9	1,796,640,616			
16	General & Intangible	L.4 - L.10	175,458,174			11,560,939
17	Common	L.5 - L.11	81,186,409			4,916,649
18	TOTAL NET PLANT	Sum of Ls. 13 - 17	$ 9,238,279,919	NP =	0.07513	$ 694,086,954
	ADJUSTMENTS TO RATE BASE	Note F				
19	Account No. 281 (enter negative)	273.8.k	$ 0	NA		
20	Account No. 282 (enter negative)	275.2.k	(2,010,522,465)	NP	0.07513	$ (151,050,553)
21	Account No. 283 (enter negative)	277.9.k & Note W	(260,320,730)	NP	0.07513	(19,557,896)
22	Account No. 190	234.8.c & Note W	576,941,127	NP	0.07513	43,345,587
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.07513	0
24	Network Upgrade (enter negative)	Note X	(2,022,808)	TP	0.95575	(1,933,299)
25	LSE Direct Assignment (enter negative)	Note X	(7,692,296)		1.00000	(7,692,296)
26	Transmission Plant ARO -- Net Balance (enter negative)		(563,237)	TP	0.95575	(538,314)
27	Common Plant ARO -- Net Balance (enter negative)		0	CE	0.06056	0
28	TOTAL ADJUSTMENTS	Sum of Ls. 19 - 27	$ (1,704,180,409)			$ (137,426,771)
29	LAND HELD FOR FUTURE USE	214.x.d; Notes G & Z	$ 0	TP	0.95575	$ 0
	WORKING CAPITAL	Note H				
30	CWC	calculated	$ 30,055,438			$ 5,923,462
31	Materials & Supplies	227.8.c & 16.c; Note G	10,671,809	TE	0.82591	8,813,954
32	Prepayments (Account 165)	111.57.c	13,985,848	GP	0.08434	1,179,566
33	TOTAL WORKING CAPITAL	Sum of Ls. 30 - 32	$ 54,713,095			$ 15,916,982
34	Rate Base	Sum of Ls. 18,28,29,33	$ 7,588,812,605			$ 572,577,165

ATTACHMENT O
RATE FORMULA FOR POINT TO POINT TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015

LG&E and KU

Line No.	(1)	(2) Form No. 1 Page, Line, Col.		(3) Company Total	(4) Allocator			(5) Transmission (Col 3 times Col 4)
	O&M							
1	Transmission	321.112.b; see also Note V	$	46,190,355	TE	0.82591	$	38,149,076
2	Less Account 565 (enter negative)	321.96.b		(4,174,529)		1.00000		(4,174,529)
3	A&G	323.197.b		205,099,094	W/S	0.06589		13,513,979
4	Less FERC Annual Fees (enter negative)	351.2.h		(757,340)	W/S	0.06589		(49,901)
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (enter negative)	Note I		(6,359,782)	W/S	0.06589		(419,046)
6	Plus Transmission Related Reg. Comm. Exp.	Note I		445,707	TE	0.82591		368,114
7	Common	356.1		0	CE	0.06056		0
8	Transmission Lease Payments			0		1.00000		0
9	TOTAL O&M	Sum of Ls. 1-8	$	240,443,505			$	47,387,693
	DEPRECIATION AND AMORTIZATION EXPENSE	Note Y						
10	Transmission (net of ARO depreciation)	336.7.b	$	21,719,525	TP	0.95575	$	20,758,436
11	General and Intangible	336.10.b & 336.1.f		23,308,693	W/S	0.06589		1,535,810
12	Common (net of ARO depreciation)	336.11.b		19,221,540	CE	0.06056		1,164,056
13	TOTAL DEPRECIATION	Sum of Ls. 10-12	$	64,249,758			$	23,458,302
	TAXES OTHER THAN INCOME TAXES	Notes J & Z						
	LABOR RELATED							
14	Payroll	263.i	$	16,525,945	W/S	0.06589	$	1,088,895
15	Highway and vehicle	263.i		90,932	W/S	0.06589		5,992
16	PLANT RELATED							
17	Property	263.i		44,916,728	GP	0.08434		3,788,277
18	Other	263.i		5,107,720	GP	0.08434		430,785
19	Payments in lieu of taxes			0	GP	0.08434		0
20	TOTAL OTHER TAXES	Sum of Ls. 14-19	$	66,641,325			$	5,313,949
	DEVELOPMENT OF INCOME TAXES	Note K						
21	T = 1 - ([(1 - SIT) x (1 - FIT)] ÷ (1 - SIT x FIT x p))			38.90%				
22	CIT = (T ÷ (1 - T)) x (1 - (WCLTD ÷ R)), where:			50.29%				
	WCLTD =	Pg 4 of 5, L. 28		1.55%				
	R =	Pg 4 of 5, L. 31		7.38%				
	FIT, SIT and p	Note K						
23	Income Tax Gross Up Factor: 1 / (1 - T)	T = L. 21		1.63666121				
24	Amortized Investment Tax Credit (enter negative)	266.8.f; see also Note K		0				

25	Income Tax Calculation	L. 22 x L. 28	$ 281,651,343			$ 21,250,640
26	ITC adjustment	L. 23 x L. 24	0	NP	0.07513	0
27	Total Income Taxes	Sum of Ls. 25-26	$ 281,651,343			$ 21,250,640
28	RETURN (rate base times rate of return)	Pg 2 of 5, L.34 x Pg 4 of 5, L. 31	$ 560,054,370			$ 42,256,195
29	REVENUE REQUIREMENT	Sum of Ls. 9,13,20,27,28	$ 1,213,040,301			$ 139,666,779

ATTACHMENT O
RATE FORMULA FOR POINT TO POINT TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015

LG&E and KU
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN LG&E and KU RATES			
1	Total transmission plant	Pg 2 of 5, L.2, C.3		$ 1,189,651,345
2	Less transmission plant excluded from LG&E and KU rates	Note M		52,642,796
3	Less transmission plant included in OATT Ancillary Services	Note N		0
4	Transmission plant included in LG&E and KU rates	L. 1 - L.2 - L.3		$ 1,137,008,549
5	Percentage of transmission plant included in LG&E and KU Rates	L.4 ÷ L.1	TP=	0.95575
	TRANSMISSION EXPENSES			
6	Total transmission expenses	Pg 3 of 5, L.1, C.3		$ 46,190,355
7	Less transmission expenses included in OATT Ancillary Services	Note L		6,274,911
8	Included transmission expenses	L. 6 - L.7		$ 39,915,444
9	Percentage of transmission expenses after adjustment	L.8 ÷ L.6		0.86415
10	Percentage of transmission plant included in LG&E and KU Rates	L. 5	TP	0.95575
11	Percentage of transmission expenses included in LG&E and KU Rates	L.9 x L.10	TE=	0.82591

Line No.	WAGE & SALARY ALLOCATOR (W&S)	Form 1 Reference	Total W&S	TP		Allocated W&S			
12	Production	354.20.b	$ 79,373,567	0.00		$ 0			
13	Transmission	354.21.b	9,196,900	0.95575		8,789,937			
14	Distribution	354.23.b	26,803,734	0.00		0		W&S Allocator	
15	Other	354.24,25,26.b	18,031,188	0.00		0		(Allocated W&S ÷ Total W&S)	
16	Total Wages and Salaries	Sum of Ls. 12-15	$ 133,405,389			$ 8,789,937	=	0.06589	= W/S

Line No.	COMMON PLANT ALLOCATOR (CE)	Note O	Total Plant					
17	Electric	200.3.c	$ 10,981,269,334					
18	Gas	201.3.d	966,619,554					
19	Water	201.3.e	0					
20	Total Plant	Sum of Ls. 17-19	$ 11,947,888,888					
21	Electric Plant Ratio	L. 17 ÷ L. 20		0.91910	times W/S (L. 16)	0.06589	0.06056	= CE

Line No.	DEVELOPMENT OF RATE OF RETURN (R)		Total per Form 1
22	Long Term Interest	117.62-67.c; Note W	$ 133,811,886
23	Preferred Dividends	118.29.c	0
	Development of Common Stock:		
24	Proprietary Capital	112.16.c	$ 4,619,623,241
25	Less Preferred Stock (enter negative)	L.29	0

Line	Description	Source		Total Company	%	Cost Rate (Note P)		Weighted	
26	Less Accounts 216.1 & 219 (enter negative)	112.12.c; 112.15.c		(1,627,215)					
27	Total Common Stock	Sum of Ls. 24-26	$	4,617,996,026					
	Weighted Average Cost of Capital:			Total Company	%	Cost Rate (Note P)		Weighted	
28	Long Term Debt	112.18-23.c; Note W	$	3,995,860,070	46.39%	0.0335		0.0155	= WCLTD
29	Preferred Stock	112.3.c		0	0.00%	0.0000		0.0000	
30	Common Stock	L.27		4,617,996,026	53.61%	0.1088		0.0583	
31	Total	Sum of Ls. 28-30	$	8,613,856,096				0.0738	= R

Line	Description		Source		Load
	REVENUE CREDITS				
	ACCOUNT 447 (SALES FOR RESALE)				Load
32	a. Bundled Non-RQ Sales for Resale (kW)		310-311, Note Q		0
33	b. Bundled Sales for Resale included in Divisor on page 1 (kW)		311.x.h; Note Z		0
34	Total (kW)		L. 32-L.33		0
35	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)		Note R	$	0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)	Notes U & Z		
36	a. Transmission charges for all transmission transactions			$	27,354,398
37	b. Transmission charges for all transmission transactions included in Divisor on Page 1				25,213,757
38	Total		L. 36-L.37	$	2,140,641

ATTACHMENT O
RATE FORMULA FOR NETWORK INTEGRATION TRANSMISSION SERVICE
RATE FORMULA FOR POINT TO POINT TRANSMISSION SERVICE

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2015

LG&E and KU

General Note: References to pages in this formula rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Average of monthly peak amounts reported on Page 400, column e of Form 1.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1 at the time of the LG&E and KU coincident monthly peaks.
C	Average of monthly peak amounts reported on Page 400, column f + column h.
D	Labeled LF on page 328 of Form 1 at the time of the LG&E and KU coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to ASC 715 and ASC 740. Balance of Account 255 is reduced by prior flow throughs and excluded if LG&E and KU chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 9, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 6 - Regulatory Commission Expenses directly related to transmission service, LG&E and KU filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Taxes related to income are excluded.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If LG&E and KU is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, if LG&E and KU elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, LG&E and KU must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f; transmission related only) multiplied by (1/1-T) (page 3, line 26). (LG&E elected to amortize tax credits against taxable income; KU elected to amortize tax credits below the line and reduce rate base. Current income tax credit balances for LG&E and KU are related 100% to production investment and are not included in the Attachment O.)

Inputs Required:	FIT =	35.00%	
	SIT=	6.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. LG&E and KU generator step-up facilities are included in production plant accounts and are not included in this Attachment O.

O Enter dollar amounts. Common Plant Allocator (CE) = ratio of electric only plant to total plant, multiplied by W/S (wages and salaries allocator).

P Debt cost rate = long-term interest (line 22) ÷ long term debt (line 28). Preferred cost rate = preferred dividends (line 23) ÷ preferred outstanding (line 29). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q Line 34 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S [Reserved]

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from LG&E and KU (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

V This Attachment O reflects a pass-through of the costs associated with the ITO and the Reliability Coordinator and excludes amortization of regulatory assets when such amortization is charged to transmission O&M and recovered entirely from retail customers.

W The amounts included in this Attachment O are net of purchase accounting adjustments resulting from the 2010 acquisition of LG&E and KU by PPL Corp. These adjustments are necessary to insulate customers from costs related to the acquisition.

X Entry on Page 2, Line 24 shall include the Network Upgrade value included in Line 2 and any accumulated depreciation included in Line 8. Entry on Page 2, Line 25 shall include the Load Serving Entity direct assigned value included in Line 2 and any accumulated depreciation in Line 8.

Y Depreciation rates and accumulated depreciation balances used in this formula include adjustments to reflect depreciation rates on file with the FERC.

Z FERC Form 1 pages do not specify line numbers, which are subject to change from year to year and between LG&E and KU. Please see the line item descriptions for identification of amounts from FERC Form 1 included in this rate formula.

Depreciation Rates Used in Attachment O

For Kentucky Utilities Company:

Property Group	Current Rates ASL
Transmission Plant	
350.1 Land Rights	0.98%
350.2 Land	0.00%
352.1 Struct. and Impr. Non Sys Control	1.54%
352.2 Struct. and Impr. Sys Control	1.43%
353.1 Station Equipment	1.98%
353.2 Syst Control/Microwave Equip	0.46%
354 Towers & Fixtures	1.21%
355 Poles & Fixtures	2.28%
356 Overhead Conductors and Devices	1.79%
357 Underground Conduit	2.60%
358 Underground Conductors & Devices	1.26%
359 Asset Retirement Obligations - Transmission *	
Total Transmission Plant	

For Louisville Gas and Electric Company:

Property Group	Current Rates ASL
ELECTRIC PLANT	
Electric Transmission Plant	

350.2 Transmission Lines Land	0.00%
350.1 Land Rights	3.92%
352.1 Structures & Improvements	1.17%
353.1 Station Equipment	1.32%
354 Towers & Fixtures	1.38%
355 Poles & Fixtures	2.95%
356 Overhead Conductors & Devices	2.52%
357 Underground Conduit	1.85%
358 Underground Conductors & Devices	3.65%
359 Asset Retirement Obligations - Transmission *	
Total Transmission Plant	

* Asset retirement obligations do not have specific depreciation rates; AROs are depreciated at the same rates as the underlying physical assets.

LG&E and KU
SCHEDULE 1 FORMULA DEVELOPMENT

Line No	Description	Reference	Total
Expense		Form 1 Page	
1	Load Dispatching		
2	Load Dispatch-Reliability	321.85.b	775,075
3	Load Dispatch-Monitor & Operate Transmission System	321.86.b	3,038,365
4	Load Dispatch-Transmission Service and Scheduling	321.87.b	1,074,136
5	Scheduling, System Control & Dispatch Services	321.88.b	-
6	Reliability, Planning & Standards Development	321.89.b	1,379,186
7	Transmission Service Studies	321.90.b	8,149
8	Generation Interconnection Studies	321.91.b	-
9	Reliability, Planning & Standards Development Services	321.92.b	-
10	Sum of O&M Expenses		6,274,911
Revenue			
11	Scheduling System Control & Dispatch	398	863,504
12	Revenue from Network & Long Term		(801,658)
13	Short-Term and Non-Firm Revenue	line 11 + line 12	61,846
14	Revenue Requirement	line 10 - line 13	6,213,065
15	Transmission System 12 CP	Att. O, pg 1, line 15	6,638,500
16	Annual Schedule 1 Rate	line 14 / line 15	0.9359
17	Monthly rate	line 16 / 12	0.0780

UTILITY VEGETATION MANAGEMENT AND BULK ELECTRIC RELIABILITY REPORT FROM THE FEDERAL ENERGY REGULATORY COMMISSION

SEPTEMBER 7, 2004

Executive Summary

Electric transmission owners and operators conduct vegetation management to prevent physical contact between transmission lines and nearby vegetation that could cause a transmission line to fail. On August 14, 2003, an electric power blackout affected large portions of the Northeast and Midwest United States and Ontario, Canada. President George W. Bush and Prime Minister Jean Chrétien established a joint U.S.-Canada Power System Outage Task Force (Task Force) to investigate the causes of the blackout and how to reduce the possibility of future outages. On April 5, 2004, the Task Force issued a Final Blackout Report[1] stating that one of the four primary causes of the blackout was inadequate vegetation management (tree pruning and removal).

In response to the Final Blackout Report, the Federal Energy Regulatory Commission (Commission) directed all designated transmission owners to file reports with the Commission by June 17, 2004, explaining their vegetation management practices for designated transmission facilities and rights-of-way.[2] The Commission staff worked with the leadership of the National Association of Regulatory Utility Commissioners' (NARUC) ad-hoc Committee on Critical Infrastructure to analyze these reports to look for significant patterns and potential problems in the vegetation management practices of the electric industry. This report to Congress summarizes the Commission's findings and recommendations. In this report, the Commission also recommends that Congress enact legislation providing for mandatory, enforceable reliability rules.

Key Observations

The transmission owners were asked to report on the results of their most recent transmission line vegetation management inspections, necessary remedial actions identified, and whether such actions had been completed before the summer 2004 peak

[1] U.S.-Canada Power System Outage Task Force, Final Report on the August 14th Blackout in the United States and Canada: Causes and Recommendations (April 2004) (Final Blackout Report).

[2] Order Requiring Reporting on Vegetation Management Practices Related to Designated Transmission Facilities, 107 FERC ¶ 61,053 (2004) (Vegetation Management Order). "Designated transmission facilities" are defined, for the purposes of the Vegetation Management Order only, as transmission lines with a rating of 230 kV or higher as well as tie-line interconnection facilities between control areas or balancing authority areas (regardless of kV rating) and "critical" lines as designated by the regional reliability council. *See* NERC, August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts at 9 n.3 (Feb. 10, 2004).

load season. Review of the vegetation management filings found that it appears transmission owners and operators have performed extensive vegetation management along the nation's high-voltage transmission network, which should produce better grid reliability during the summer. However, there is a wide range of vegetation management practices and procedures among the reporting transmission owners. There is very little uniformity in regard to right-of-way width,[3] vertical line clearance,[4] inspection frequency,[5] and vegetation management guidelines[6] used. The lack of uniformity may be understandable in part, as transmission owners must design their vegetation management practices based on factors such as the demands of the terrain, location, climate, vegetation species, and local laws and regulations.

The Commission recognizes that, while the data filed in response to the Vegetation Management Order reveals each transmission owner's practice, it does not directly address how effective the practice has been in limiting preventable transmission line outages. The Commission did not ask for such data in the April request, because similar data are now being reported to the Western Electricity Coordinating Council and to the North American Electric Reliability Council (NERC). Such a review is beyond the scope of this report.

Transmission owners report that they are not able to acquire all necessary permits to maintain their rights-of-way from various federal and state agencies. However, this problem could be alleviated, at least in part, if the acquisition of these permits is made a higher priority on the part of transmission owners. For instance, transmission owners could allow additional lead time to acquire many needed permits. The agencies responsible for issuing permits, however, should ensure that they have clear rules and procedures for issuing permits in a timely manner.

With respect to any jurisdiction issues that may arise involving vegetation management, it is important that state and federal regulators continue to coordinate so that jurisdictional considerations do not impede effective vegetation management.

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[3] A right-of-way is a segment of land used for the route of a transmission line. A right-of-way should be devoid of vegetation that can interfere with a transmission line. The right-of-way width is the distance between the outer bounds of a right-of-way.

[4] The vertical distance between a tree or vegetation and an electric transmission wire.

[5] The time between complete inspections of a utility's transmission system, *e.g.*, semiannual, annual, etc.

[6] The guidelines that utilities report they adhere to in regards to the management of vegetation along transmission lines.

The Commission believes that better coordination among federal agencies and between the federal and state governments to develop clear, consistent policies and procedures for timely and effective vegetation management by transmission owners could help to alleviate many real and perceived obstacles to proper vegetation management.

The transmission owners reported that vegetation management approvals on federally managed rights-of-way are particularly problematic in the Western United States. The Council on Environmental Quality (CEQ) coordinates federal environmental efforts and helps resolve inter-agency differences over environmental issues. The Commission believes federal agencies and the CEQ should work together on vegetation management on federal rights-of-way. In addition, the CEQ could facilitate coordination with Native American tribes for vegetation management on Native American tribal lands. We understand that vegetation management practices affect the environment and look forward to working with other agencies to coordinate efforts to assure that neither the environmental quality of federal lands nor regional electric reliability are put at risk.

Summary of Recommendations

1) The United States Congress should enact legislation to make reliability standards mandatory and enforceable under federal oversight.

2) Effective transmission vegetation management requires clear, unambiguous, enforceable standards that adequately describe actions necessary by each responsible party.

3) With respect to any jurisdiction issues that may arise involving vegetation management, it is important that state and federal regulators continue to coordinate so that jurisdictional considerations do not impede effective vegetation management.

4) Federal and state regulators should allow reasonable recovery for the costs of vegetation management expenses.

5) While permitting and environmental requirements properly protect public lands, the procedures implementing those protections may be inconsistent and time-consuming and have the potential to significantly hinder transmission vegetation management. The Commission should work with the CEQ and land management agencies to better coordinate these requirements.

6) Federal, state and local land managers should develop “rush” procedures and emergency exemptions to allow utilities to correct “danger” trees[7] that threaten transmission lines, from both on and off documented rights-of-way.

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[7] A danger tree is a tree that is dead or dying and has the potential to fall into a

7) Five-year vegetation management cycles should be shortened, and the Commission and states should look at the cost-effectiveness of more aggressive vegetation management practices.

8) Transmission owners should fully exercise their easement rights for vegetation management and better anticipate and manage the permitting process for scheduled vegetation management.

9) Variances in vegetation management practices may be resolved in the NERC vegetation management standard development process; if they are not, the Commission may seek to convene the industry, states and other stakeholders to address the remaining issues.

10) State regulators and the utility industry should work through NARUC, the National Conference of State Legislators, and other organizations to help state and local officials better understand and address transmission vegetation management.

Introduction

On August 14, 2003, an electric power blackout occurred over large portions of the Northeast and Midwest United States and Ontario, Canada. The blackout lasted up to two days in some areas of the United States and longer in some areas of Canada. It affected an area with over 50 million people and 61,800 megawatts of electric load. In the wake of the blackout, a joint U.S.-Canada Task Force (Task Force) undertook a study of the causes of that blackout and possible solutions to avoid future such blackouts. The Task Force's Final Report was issued on April 5, 2004.

The Task Force identified FirstEnergy Corporation's (FirstEnergy) failure to adequately prune trees and manage vegetation in its transmission rights-of-way as one of the four primary causes of the August 14, 2003 blackout.[8] The blackout investigation explained that, during the hour before the cascading blackout occurred, three FirstEnergy 345 kV transmission lines failed as a result of contact between the lines and overgrown vegetation that encroached into the required clearance zone for the lines.[9] It stated that "because the trees were so tall . . . each of these [three] lines faulted under system conditions well within specified operating parameters."[10]

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right-of-way close to a line.

[8] Final Blackout Report at 20.

[9] *Id.* at 57-67.

[10] *Id.* at 58.

The Final Blackout Report also compared the August 2003 blackout with seven previous major outages and concluded that conductor contact with trees was a common factor among the outages.[11] The Task Force emphasized that vegetation management is critical, and that many outages can be prevented by managing vegetation before it becomes a problem.[12] It also noted that investigation reports from previous major outages recommended paying special attention to the condition of vegetation on rights-of-way and the need for preventative maintenance in this area.

In March 2004, the Commission made available to the public a 128-page vegetation management report, prepared to support the blackout investigation.[13] The report details problems with vegetation management relating to the August 2003 blackout, and the impact of vegetation management on electric reliability. The report concludes that the August 2003 blackout likely would not have occurred had the rights-of-way been maintained for three 345 kV transmission lines that tripped due to tree-line contacts.[14] It also concludes that utilities responsible for the right-of-way maintenance had in place vegetation management programs that were in line with current industry norms. Further, it concludes that current industry "standards" are inadequate and must be improved. The CNUC Final Vegetation Report recommends specific practices that would reduce the likelihood of tree and power line contacts and provides recommendations for the oversight and enforcement of utility vegetation management activities.

On April 19, 2004, the Commission issued the Vegetation Management Order requiring all entities that own, control or operate designated electric transmission facilities in the lower 48 states to provide information on their vegetation management practices. This order was issued pursuant to section 311 of the Federal Power Act, 16 U.S.C. § 825j (2000) which authorizes the Commission to conduct investigations in order to secure information necessary or appropriate as a basis for recommending legislation.

The Commission ordered that designated transmission owners describe in detail the practices and standards that the transmission owner uses for control of vegetation near designated transmission facilities, and indicate the source of any standard utilized (*e.g.* state law or regulation, historical practice). In addition, transmission owners were asked

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[11] *Id.* at 107.

[12] *Id*. at 59.

[13] CN Utility Consulting, Utility Vegetation Management Final Report, (March 2004) (CNUC Final Vegetation Report). The CNUC Final Vegetation Report is available on the Internet at www.ferc.gov/cust-protect/moi/blackout.asp.

[14] *Id*. at 26-27.

to describe the clearance assumptions or definition used for the appropriate distance between vegetation and the facilities, how often the transmission provider inspects that facility for vegetation management purposes, whether identified remediation has been completed as of June 14, 2004, and any factors that the respondent believes prevents, or unduly delays, the performance of adequate vegetation management.[15]

This report analyzes the information gathered pursuant to the Vegetation Management Order, provides relevant additional information regarding the current status of vegetation management practices, and offers a recommendation for Congressional consideration.

Review and Analysis Method

The Commission received 161 responses from transmission owners.[16] On June 21-22, 2004, Commission staff, along with three state commissioners, Connie Hughes of New Jersey, Don Mason of Ohio, and Judith Ripley of Indiana, representing the leadership of the NARUC ad-hoc Committee on Critical Infrastructure, performed an initial review of the vegetation management responses.[17] This initial two-day review was intended to identify any immediate issues that could potentially impact electric grid reliability requiring rapid follow up by state or federal regulators. In addition, it looked for progress made since the blackout of the previous year, fact patterns suggesting additional inquiry is required, and a general overview of current vegetation management practices. The initial review was followed up by a more intensive Commission staff data analysis. This analysis included the creation of a database that tracked:

- all respondents' right-of-way width maintained in feet by voltage,
- vertical line clearance in feet by voltage,
- ground and aerial inspection frequency,
- vegetation management cycle,[18] and
- vegetation management guidelines utilized, if any.

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[15] Vegetation Management Order at P 12.

[16] Some respondents provided responses on behalf of multiple operating companies or multiple transmission owners.

[17] Edison Electric Institute (EEI) prepared templates for its members to use in filing the requested data. Many EEI members used these templates. The templates made it easier for Commission staff to review the filings.

[18] The period of time required for a utility to perform maintenance including the pruning of all vegetation and the removal of all vegetation of concern on its entire transmission system.

Commission staff reviewed the data in the five categories above and looked for patterns in vegetation management practices.[19]

Findings

The majority of respondents have completed necessary vegetation management remediation measures identified during the most recent inspection of their transmission lines. While this does not guarantee that there will not be adverse impact to grid reliability caused by vegetation interfering with transmission lines, it is a positive indication of reduced risk to reliability. However, 29 percent of respondents identified some line vegetation management remediation that was not completed by the June 17 filing date and may not be performed this summer.[20] A list of these respondents is provided in Attachment A. The results suggest that a significant amount of the remediation occurred between April 19, 2004 and June 14, 2004.

Utility vegetation management practices vary significantly. While some variation is expected because vegetation management practices are affected by climate, terrain, vegetation species, local laws, and regulations, other variations are unexplained. Below is a discussion of reported data on right-of-way width, vertical clearances, inspection frequency, vegetation management cycles, and vegetation management guidelines followed. Some of these variations may be resolved in the NERC vegetation management standard development process;[21] if they are not, the Commission may seek to convene the industry, states and other stakeholders to address the remaining issues.

1. Right-of-way Width

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[19] In their filings, certain respondents asked for and were granted protection regarding specific transmission line information under the Commission's Critical Energy Infrastructure Information (CEII) policy. CEII is information concerning proposed or existing critical infrastructure (physical or virtual) that relates to the production, generation, transmission or distribution of energy. While this report does not disclose any specific CEII data, the Commission's conclusions reflect its review of such data.

[20] In some instances, the transmission owner/operator reported that remediation before the summer was not needed and would be completed as part of the regular vegetation management cycles later in the year. In other instances, the respondent states that there is no immediate threat to the line. Some stated that the work would be completed shortly after June 17 or as soon as possible. In at least one case, the required work was pending reaching agreement with a landowner.

[21] NERC recently initiated a vegetation management standard development process. *See* ftp://www.nerc.com/pub/sys/all_updl/docs/bot/Agenda-Items-0604/Item12e.pdf.

Right-of-way widths vary significantly among the reporting transmission owners. Generally, right-of-way width increases as line voltage increases. Higher voltage lines require wider rights-of-way because greater separation is needed between conductors. Wider right-of-way widths are also necessary to accommodate multiple lines and in some cases more than one tower. Since right-of-way width depends on many factors, and since some respondents provided ranges that depend on such factors as the number of circuits on a right-of-way, no pattern was identified from the data on the range of right-of-way widths. Table 1 shows the range of responses by voltage class.

Table 1. Right-of-Way Width

Right-of-Way Width							
500 kV		345 kV		230 kV		Less than 230 kV	
Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies
Less than 125	4	Less than 75	6	Less than 75	40	Less than 50	51
126-175	21	76-125	36	76-125	36	51-125	41
176 >	13	126 >	30	126 >	30	126 >	7

In general, if a utility has a wider right-of-way, well documented right-of-way easement rights, and exercises those rights fully, it will be more successful in avoiding vegetation-line contact than a utility that maintains narrower rights-of-way. A narrow right-of-way increases the risk of contact with vegetation that is outside of the right-of-way and adjacent to the transmission line. Expert commentary included in the CNUC Final Vegetation Report stated, "[m]ost tree/power line contacts occur when trees fall onto lines from outside the rights-of-ways or corridors. Many utilities are slow to act to address this issue due to the perception of increased costs and the pressure from landowners etc. to leave trees standing."[22]

2. Inspection Frequency

Vegetation management inspections are performed to inspect the status of vegetation and the rights-of-way surrounding electric transmission facilities. During these inspections, vegetation of concern is noted and scheduled for remediation. Typically, a utility will utilize a combination of aerial and ground inspections. Ground inspections are performed by walking or driving the length of transmission lines to inspect the condition of vegetation. While slow, ground inspections may be more effective because they enable an inspector to more thoroughly view vegetation conditions and the relationship between vegetation and the wire. Aerial inspections are performed using aircraft (a helicopter or a small plane flying at low altitude) to visually inspect the

[22] CNUC Final Vegetation Report at 115.

condition of vegetation. Given the greater distance from the vegetation and the speed of aerial inspection, it is considered to be less reliable and thorough than ground inspection.

Annual, semi-annual, or more frequent aerial patrols are part of the transmission inspection practice of 105 utilities, twenty-five of which conduct aerial inspections more frequently than twice a year. Table 2 summarizes the responses.

Table 2. Aerial Inspection Frequency

Aerial Inspection	
Frequency	# of Companies
More than twice a year	25
Semi-annual	34
Annual	46
Biennial	6
Every 3 years	1
> than 3 Years	3
As Needed	8
Did Not Report	38

Most transmission owners use aerial patrols to identify areas that need remediation or areas that will need remediation soon. Aerial inspections are followed by additional ground inspection or remediation.

Over 100 respondents indicate that they conduct annual or more frequent ground inspections of their entire system. Ground patrols are more effective in identifying vegetation-related problems.[23] Table 3 summarizes the responses.

[23] CNUC Final Vegetation Report at 49.

Table 3. Ground Inspection Frequency

Ground Inspection	
Frequency	# of Companies
More than twice a year	7
Semi-annual	22
Annual	76
Biennial	6
Every 3 years	6
> than 3 Years	25
As Needed	12
Did Not Report	7

As with right-of-way width, patrol frequency and method varies significantly among reporting utilities. This could be due to the variation in the number of transmission circuit miles owned or operated by the utility, terrain, and vegetation characteristics.

3. Vertical Clearance

Vertical clearance is the distance between a wire and the vegetation directly below it.[24] The minimum vertical clearance requirement increases by line voltage (although some transmission owners reported the same vertical clearance for all voltage classes). The maintenance of sufficient vertical distance between the conductor and vegetation is essential because direct physical contact is not necessary for a line outage to occur. An electric arc can occur between a part of a tree and a nearby high-voltage conductor without sufficient clearance.[25] These electric arcs can cause fires and line outages. Vegetation management practices should maintain a minimum vertical clearance between a line and a tree. The pruning should create clearances with a healthy safety margin beyond the minimum required clearance that will last until the next scheduled pruning or treatment. Table 4 shows vertical clearances used by reporting utilities.

[24] Vegetation can interfere with power lines from below, sides, and above and appropriate clearance must be maintained all around the wire. This section discusses vertical line clearance as an example of the variation among utilities in maintaining line clearances.

[25] In effect, electricity on a transmission wire can "jump" a very short distance from the wire to tree limbs without direct contact, creating a short circuit that can lead to a line outage.

Table 4. Vertical Clearances Reported

Vertical Clearance Table							
500 kV		345 kV		230 kV		Less than 230 kV	
Clearance (ft)	# of Companies	Clearance (ft)	# of Companies	Clearance (ft)	# of Companies	Clearance (ft)	# of Companies
0-15	11	0-15	17	0-10	23	0-10	16
16-20	11	16-20	17	11-15	17	11-15	20
21-25	9	21-25	12	16-20	24	16-20	14
26>	8	26 >	14	21-25	16	21-25	3
				26 >	13	26 >	5

There is no apparent rationale for the wide variance in vertical clearance requirements.[26] The current industry effort through NERC to develop a vegetation management standard should resolve this issue.

4. Vegetation Management Cycle

A vegetation management cycle is loosely defined as the time it takes to complete the pruning and removal of trees or other vegetation on a utility's entire transmission system. In most cases, a utility prunes or treats a portion of its total circuit-miles of right-of-way in each year; once the circuit is completed, the company starts the cycle over. The Vegetation Management Order did not formally request this information, but the CNUC Final Vegetation Report found that a five-year cycle is the industry norm. Furthermore, the report found that the five-year cycle is insufficient to maintain reliability.

Of the 70 respondents that volunteered their vegetation management cycles, many indicate that they prune and remove vegetation along their lines within a five-year or longer interval.[27] Table 5 summarizes the responses.

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[26] There could have been varying interpretations of the reporting requirement (*e.g.*, clearance achieved at the time of pruning vs. minimum clearance maintained). However, the EEI templates used by a large number of respondents instructed that "minimum clearance maintained between conductor and vegetation" be reported.

[27] A five-year cycle is consistent with the industry practice; however, common or average industry practices need improvement. Final Blackout Report at 59.

Table 5. Pruning Cycle

Pruning Cycle	
Frequency	# of Companies
0-2 years	11
3-4 years	35
5 or More years	24

In the future, the Commission and the industry should work to identify the correlation between vegetation management practices and actual vegetation-caused transmission line outages.

When managing vegetation, 93 companies employ herbicides to limit vegetation growth; others use mechanical techniques to cut vegetation on rights-of-way; and some use a combination of both.[28]

5. Current Vegetation Management Guidelines

Establishing clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in rights-of-way was one of the recommendations of the Final Blackout Report.[29] The vast majority of transmission owners report that they follow the National Electrical Safety Code (NESC) rules or American National Standards Institute (ANSI) guidelines, or both when managing vegetation around transmission lines. The NESC deals with electric safety rules, including transmission wire clearance standards, while the applicable ANSI code deals with the practice of pruning and removal of vegetation. However, these rules and guidelines are not specific with regard to clearances between transmission lines and vegetation and are subject to interpretation. Nor do these rules provide a performance target for keeping vegetation from conflicting with transmission lines. Furthermore, these standards are not enforceable upon transmission owners, but have been adopted by NESC and ANSI as guidelines for appropriate practice.

- 104 utilities indicate that they adhere to NESC standards for transmission system maintenance.
- 92 of these specifically adhere to NESC Rule 218, which only provides that

[28] Mechanical and chemical techniques are not mutually exclusive in general. Rather, mechanically clearing, *e.g.* with a bushhog, might take place followed by treatment with herbicide to retard regrowth.

[29] Final Blackout Report at 154.

trees that may interfere with conductors should be trimmed or removed. NESC Rule 218 does not prescribe clearances.

- 12 reported that they specifically follow NESC Rule 232, 233 or 234 which prescribes clearances of wires from ground, structures, and other installations.
- 34 respondents follow ANSI A300, which deals with proper tree pruning techniques to maintain the health of the tree, and does not contain any clearance requirements.
- ANSI Z133, used by 22 transmission owners, provides guidelines for utilities related to worker and public safety during tree pruning and removal operations.
- A large number of respondents adhere to NESC standards in conjunction with ANSI standards such as A300.
- 96 transmission owners report that they use internally-developed, state, or other guidelines.

Respondents did not explain why they follow a particular standard. As stated earlier, NERC is in the process of developing a vegetation management standard that may resolve the current lack of a clear, unambiguous standard.

Good Practices

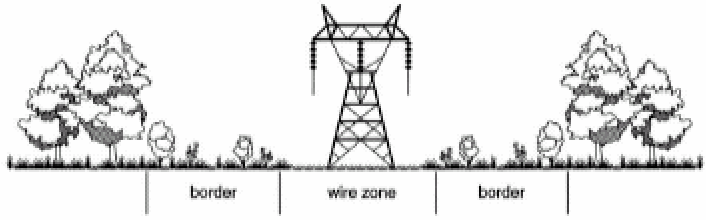
The CNUC Final Vegetation Report identified a number of good utility vegetation management practices. Among these good practices for existing rights-of-way are:

- Application of wire zone – border zone concepts (described below)
- Proper consideration of line sag and sway
- Frequent field inspection of vegetation conditions
- Comprehensive public education programs

In reviewing the filings, Commission identified a number of utilities that report practices consistent with the best practices identified in the CNUC Final Vegetation Report. Some examples follow.

One good practice relates to customer education. For example, some utilities have public outreach programs that educate the public about tree types and line clearances so that citizens will have the knowledge to report vegetation that is dangerous to transmission wires.

Several transmission owners employ a wire zone – border zone approach which is both environmentally friendly and effective in ensuring reliability. This method involves creating a low-growing vegetation environment directly under transmission lines, which physically prevents dangerous vegetation from encroaching into energized transmission facilities. The CNUC Final Vegetation Report stated that the wire zone-border zone has "been proven to be effective in reducing and/or eliminating outages related to vegetation on transmission ROW [rights of way]."[30] The wire zone-border zone concept is depicted in the graphic below.



Several companies have taken measures to improve vegetation management-related reliability. Certain utilities, for example, conduct frequent ground and aerial patrols, as well as an inspection of all of its power lines after every major storm.

Reported Obstacles to Effective Vegetation Management

In trying to understand the state of the industry's vegetation management programs, the Vegetation Management Order sought information on factors that the utilities believe prevent or unduly delay their performance of adequate vegetation management. Sixty-six utilities report that their efforts to properly maintain their transmission lines are impeded by a variety of federal and state regulations that legally or practically prevent them from performing effective vegetation management. While such ordinances can be problematic and hinder the vegetation management process, proper planning and foresight on the part of the utilities, including allowances for additional lead time, would likely reduce the threat to vegetation management caused by some ordinances.

[30] CNUC Final Vegetation Report at 21.

List of Reported Obstacles	
Reported Obstacles	**Responses**
U.S. Forest Service	22
U.S. Fish and Wildlife Service	12
National Park Service	6
Departments of Transportation	6
Other Federal/State/Local Governments	35
Private Landowners	20
Other	10

No transmission owners complained of the financial costs of vegetation management.

In many instances, a situation may arise in which a transmission owner is not able to plan for vegetation management. For example, trees can become hazardous to a line suddenly, as when a tree is dead or dying and has the potential to fall into a right-of-way and impact a line. These are a risk to reliability as long as the situation is not corrected, and so must be dealt with on a priority basis. Many transmission owners reported that the permitting processes can impede action necessary to properly manage situations such as this.

The conflicting goals and requirements for environmental protection and electric reliability create practical problems for vegetation management. Transmission owners cite federal regulations and their enforcement programs most frequently as impeding their ability to properly manage the vegetation within transmission line rights-of-way.[31] Twenty-two transmission owners cited U.S. Forest Service (Forest Service) restrictions on transmission owners across the country. They state that the Forest Service requires impact studies on wildlife and habitat impacts, requires environmental impact assessments, and limits the use of access roads to transmission rights-of-way and has inconsistent permitting procedures across the National Forests. In addition, twelve utilities claim that the U.S. Fish and Wildlife Service restricts the times at which trees can be pruned and limits herbicide use in order to maintain endangered species habitats. If

[31] Some of the land management agencies have already begun streamlining their permitting processes. For example, the Forest Service began overhauling its permitting and environmental review process over a year ago. These changes should reduce the impact of permitting on vegetation management.

herbicide use is limited, many manually or mechanically removed trees can re-sprout and quickly grow back into power lines. Utilities also report that the various state Departments of Transportation had restricted tree pruning and removal in the name of "beautification" efforts. Otter Tail Power reports that the U.S. Department of Transportation, the U.S. Fish and Wildlife Service, and the Department of Natural Resources have repeatedly planted trees in its rights-of-way.

Several companies stated that state government organizations had taken action that they believed hindered their reliability programs as well. For instance, PacifiCorp reports that the Utah Department of Transportation had planted trees directly under several of its 345 kV transmission lines and would not allow them to be pruned. The New York State Department of Environmental Conservation requires transmission owners to file "Temporary Revocable Permits" that take up to two years to process for transmission owners to get access to trees that need to be managed.

Respondents also claim that a variety of local regulations and property owners prevent effective vegetation management. One of the most frequent claims is local and private entities limit the use of herbicides and the removal of trees. Some local park restrictions hinder trucks from accessing power lines. Native American tribes are sovereign and can restrict transmission owners in numerous ways when transmission rights-of-way pass through tribal land. For many utilities, attempting to manage numerous local and private restrictions can be extremely burdensome and can result in failure to conduct effective vegetation management. For example, the outage that occurred on Cinergy's 345 kV Columbus – Bedford line on August 14, 2003 was due to a property owner's refusal to allow Cinergy to complete the required work.[32] Cinergy had documented rights at the location but work was halted due to a court-granted temporary injunction obtained by the property owner.

Need For Legislation

Ineffective vegetation management was a major cause of the August 14, 2003 blackout and a contributing factor to other large-scale blackouts. The U.S.-Canada Task Force found that clear, unambiguous, and enforceable standards are needed to reduce the potential for reoccurrence of vegetation related transmission line outages and recommended that NERC, in cooperation with the industry and the appropriate governmental agencies, develop such a standard.[33] The Commission's review of the responses submitted confirms a lack of common standards and significant variations among utilities in their vegetation management practices.

[32] CNUC Final Vegetation Report at 36.

[33] Final Blackout Report at 154.

NERC recently initiated a vegetation management standard development process. The Commission supports NERC's initiative to develop a clear, unambiguous vegetation management standard. However, adherence to NERC standards will be voluntary unless Congress enacts legislation with a clear federal framework for mandating development and enforcement of this and other reliability rules.

Recommendations

The following recommendations are based on the information received in response to the Vegetation Management Order. The Commission has also drawn from the Blackout Report and the CNUC Final Vegetation Report. These recommendations were developed in collaborative discussions between the Commission staff and the state commissioners who participated in the initial review.

1) The United States Congress should enact legislation to establish an Electric Reliability Organization and make its standards mandatory and enforceable, under federal oversight. Under such legislation, if the Commission were to approve a NERC standard, then it would be mandatory and enforceable for all transmission owners and operators. Mandatory, enforceable standards will result in greater compliance and, therefore reduce the likelihood of individual transmission line outages due to tree contacts, electric arcing, and fires, and thus improve local and regional grid reliability.

2) Effective transmission vegetation management requires clear, unambiguous, enforceable standards that adequately describe the actions necessary by each responsible party. The NERC standard now being developed should serve this purpose. We recognize that the details of such standards must respect differing vegetative, climate, terrain, and other considerations, and thus may need to balance between results required and detailed prescriptions for how to manage vegetation, so it will be challenging to develop a clear, effective standard. But it must be done, and done as quickly as possible to assure that the nation's customers and economy do not remain at risk to this known reliability threat.

3) With respect to any jurisdiction issues that may arise involving vegetation management, it is important that state and federal regulators continue to coordinate so that jurisdictional considerations do not impede effective vegetation management.

4) As noted above, no reporting utility suggests that lack of financial resources or recovery of vegetation management expenses is an obstacle to the achievement of vegetation management goals. Nevertheless, both federal and state regulators should be sensitive to requests for rate adjustments in order to recover reasonable reliability and security related expenses such as those for vegetation management.[34]

[34] *See, e.g.*, Policy Statement on Matters Related to Bulk System Reliability, 107

5) The Commission should work with the CEQ and the federal land management agencies to streamline and better coordinate permitting and environmental requirements to facilitate better vegetation management without compromising environmental quality. While it is entirely appropriate that federal and state land managers protect the lands for which they have responsibility, the costs and consequences of vegetation-caused outages or blackouts are so high that agencies should reexamine these processes and requirements to see whether they need to be reformed. The Commission commits to work with the CEQ and other federal land management agencies on such an effort. Additionally, the CEQ could facilitate coordination with Native American Tribes for vegetation management on Native American tribal lands.

6) Outages are often caused by trees that become hazardous to a line, as when a tree is dead or dying and has the potential to fall into a right-of-way and impact a line. These are a risk to reliability as long as the situation is not corrected, and so must be dealt with on a priority basis. State, local and federal land managers should recognize the importance of this situation and should develop priority or rush procedures to allow the utility to take prompt corrective action to mitigate these “danger” trees.

7) Since numerous recent major blackouts have been caused by tree contacts with transmission lines, and the August 14, 2003 blackout was caused by trees that were managed on a five-year vegetation management cycle, the CNUC Final Vegetation Report concluded that a five-year cycle, while the industry norm, is not effective nor adequate for assuring transmission reliability across much of North America. For that reason, a shorter cycle should be used. While this and other enhanced vegetation management requirements suggested herein may increase utility costs, given the substantial and perhaps growing costs of reliability failures of the modern grid, the Commission and the states should encourage cost-benefit studies to examine the relative costs and benefits of current and more aggressive vegetation management practices.

8) Transmission owners should work to remove the obstacles to effective vegetation management along transmission rights-of-way. This should include, at minimum:

- Whenever possible, renegotiation of easement provisions where they do not grant adequate clearance and vegetation management rights.
- Full exercise of all existing easement provisions and rights to assure adequate tree-pruning and clearing.
- Where landowners or land managers have established lengthy permitting requirements or time-limited vegetation management operational windows, planning ahead to assure that the transmission owner or operator secures the

FERC ¶ 61,052 at P 27-28 (2004).

needed permissions in a timely and predictable fashion.

9) Variances in vegetation management practices may be resolved in the North American Electric Reliability Council (NERC) vegetation management standard development process; if they are not, the Commission may seek to convene the industry, states and other stakeholders to address the remaining.

10) State regulators and the utility industry should approach NARUC, National Conference of State Legislators, and similar organizations to develop model guidelines and educational materials that can be used to help state and local officials understand the importance of this issue and how to manage it more effectively, through measures such as tree-pruning and tree-planting ordinances. If state legislation or changed agency rules are needed, utilities and state utility regulators should take the lead within each state to initiate the communications and cooperative discussions required. The Commission would support this effort, if requested.

Attachment A

Companies that did not perform all identified vegetation management remediation by the June 14, 2004 reporting date

- American Transmission Co.
- Aquila, Inc.
- Austin Energy
- Basin Electric Power Cooperative
- Black Hills Power, Inc.
- Carolina Power and Light Co.
- Central Hudson Gas and Electric Corp.
- Central Louisiana Electric Company, Inc.
- City of Tallahassee Electric Utility
- Consolidated Edison Company of New York, Inc.
- Dairyland Power Cooperative
- Entergy Corp.
- Georgia Transmission Corp.
- Indiana-Kentucky Electric Corporation
- International Transmission Co.
- Lakeland Electric
- Louisville Gas & Electric Co.
- Lower Colorado River Authority Transmission Services Corp.
- Montana-Dakota Utilities Co.
- Municipal Electric Authority of Georgia
- Nebraska Public Power District
- New York Power Authority
- NorthWestern Energy
- Nstar Electric and Gas Corp.
- Ohio Valley Electric Corp.
- Oklahoma Gas & Electric Co.
- PacifiCorp
- PPL Electric Utility Corp.
- Public Utility District No.1 of Chelan County
- Puget Sound Energy, Inc.
- Rappahannock Electric Cooperative
- Santee Cooper Power
- Seattle City Light
- Sierra Pacific Power Co.
- South Carolina Gas & Electric Co.
- South Texas Electric Cooperative, Inc.
- Texas Municipal Power Agency
- Tucson Electric Power Co.
- TXU Electric Delivery
- Western Area Power Administration
- Xcel Energy

In some instances, the transmission owner/operator reported that remediation before the summer was not needed and would be completed as part of the regular vegetation management cycles later in the year. In other instances, the respondent states that there is no immediate threat to the line. Some stated that the work would be completed shortly after June 17 or as soon as possible. In at least one case, the required work was pending reaching agreement with a landowner. On August 26, 2004, Dairyland Power Cooperative filed an update with the Commission stating that all remediation has been completed.

Attachment B

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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 441

Responding Witness: Lonnie E. Bellar

Q-441. Provide a copy of the latest study LG&E- KU conducted regarding the feasibility and cost effectiveness of joining a Regional Transmission Organization.

A-441. See attached.

RTO Membership Analysis

1 Executive Summary

A cross-functional team was assembled to conduct a high level analysis of the estimated costs and benefits of LG&E-KU ("LKE" or "the Companies") regional transmission organization (RTO) membership, specifically for Midwest Independent Transmission System Operator (MISO) and PJM Interconnection (PJM). The analysis of joining MISO and PJM covered a ten year study period from 2013 through 2022. The analysis was modeled after a similar study, EKPC RTO Membership Assessment[1], performed by Charles River Associates (CRA) for East Kentucky Power Corporation in their consideration of joining PJM.

- **RTO membership is unfavorable.** LKE's RTO Membership Analysis shows an unfavorable ten-year present value for RTO membership ranging from ($103) M for PJM to ($216) M for MISO.
- **Key driver is "backbone" transmission costs.** Allocation of large transmission expansion projects costs across RTO members is the primary cost driver of RTO membership.

2 Methodology

LKE Transmission Strategy and Planning assembled a cross–functional team for the RTO Membership Analysis.[2] The team was comprised of representatives from Transmission Policy & Tariffs, Federal Regulation & Policy, Regulated Trading and Dispatch, and Economic Analysis. The CRA EKPC RTO Membership Assessment was used as a general guideline for this analysis.

- The methodology for the LKE analysis was consistent with the methodology and testimony from the 2006 MISO exit proceedings.
- The methodology took into consideration changes to the tariff structures and business practices of the RTOs since the exit proceedings.

The intent of the analysis was to incorporate updated data and information to assess the costs and benefits of RTO membership at a high level, as opposed to an exhaustive

[1] March 2012 http://psc.ky.gov/pscscf/2012%20cases/2012-00169/20120503_ekpc_application_volume%201.pdf, Exhibit RLL-2
[2] The Compliance Department was apprised of all meetings to ensure maintenance of Standards of Conduct between Transmission function and Trading function employees.

RTO Membership Analysis

analysis. These results were viewed as a threshold to determine if further in-depth study is warranted.

3 Key Assumptions

This analysis was conducted for a ten year horizon, 2013 through 2022, a period identical to the CRA study conducted for EKPC. The following key simplifying assumptions were incorporated into the analysis:

- LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes.
- No changes in locational marginal prices (LMP) due to planned RTO transmission expansions
- No impact from Firm Transmission Rights/Auction Revenue Rights (FTR/ARR) and congestion cost
- No impact from allocation of over collection of marginal losses[3]
- No impact from uplifts or make whole payments other than those identified
- No impact from potential transmission cost sharing within alternative, non-RTO Order 1000 regional planning region

4 Cost / Benefit Components

4.1 Allocation of "Backbone" Transmission Expansion Costs

The key driver of the outcome of this analysis was the allocation of "backbone" transmission expansion costs.

- For PJM, transmission expansion costs of $176 million (present value) represent more than half of the estimated absolute cost of RTO membership (excluding the benefits).
- For MISO these costs are $241 million (present value), approximately 60% of the estimated absolute cost of membership (excluding the benefits).

4.1.1 MISO Multi-Value Projects

Under current MISO policy, the cost of new transmission projects that address energy policy and/or provide widespread benefits across the footprint are considered "multi-value projects" (MVP). The cost of MVP are allocated 100% "postage stamp" to load,

[3] MISO collects incremental value of financial losses through the locational marginal price (LMP), which can result in over–collection. MISO has a process to allocate any over–collection back to the load serving entities.

i.e., all load pays the same rate for MVP irrespective of where located in the footprint, and are recovered under Schedule 26A of the MISO Tariff. LKE's share of the $5.4 billion in MVP projects currently identified in the Midwest ISO Transmission Expansion Planning (MTEP) process is based on the "indicative annual charges for approved MVP" published on the MISO website[4], applied to LKE loads projected per the 2013 Business Plan. As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period.[5]

4.1.2 PJM Regional Transmission Expansion Planning

Under current PJM policy, the cost of new "backbone" high voltage transmission projects approved under its annual Regional Transmission Expansion Planning (RTEP) process is allocated on a uniform basis to all PJM loads based on the non-coincident annual peak of each PJM transmission zone. These charges are recovered under Schedule 12 of the PJM tariff. "Backbone" facilities comprise "Regional Facilities" that operate above 500 kV and "necessary lower voltage facilities" that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities.[6] As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period. The allocation to LKE for projects documented in the RTEP within this analysis period has been estimated using PJM's allocation methodology and is a key cost driver for the PJM case.

4.2 Modeled Components

Two components of the analysis, Operating Reserve and Trade Benefits, were estimated by Generation Planning (GP) using the Companies' planning models. Because the models were already developed for other planning purposes, only minimal changes were required to use the models to estimate these components.

4.2.1 Operating Reserve

The reduced operating reserve capacity benefits of joining MISO or PJM were estimated by reducing the Companies' "spinning reserve" requirement from 230 MW to 100 MW, for a present value benefit of $14 M. GP revised the operating reserve input in the Companies' reliability planning software, SERVM, which resulted in a target system planning reserve margin (RM) of 15% (1% lower than the existing target RM of 16%).[7]

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[4] https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=135589

[5] For discussion of the "unique circumstances" surrounding Entergy joining Midwest ISO that justify Energy's five year MVP exemption and eight year MVP cost phase-in, see 139 FERC¶ 61,056 at ¶¶ 70,181,213.

[6] CRA Study, p. 12.

[7] With the existing 16% RM target, GP would choose to purchase temporary capacity through a PPA in years with an annual RM between 14% and 15% and would choose permanent capacity in a year with a RM below 14%. With

RTO Membership Analysis

GP used this new RM to evaluate the impact to the Companies' expansion plan using a spreadsheet model to calculate the expected RM and using Strategist software.

The table below shows the expected RMs with no new capacity after Cane Run 7 in 2015 and the corresponding capacity additions needed with the existing and new target RMs.

	RM w/o New Capacity	Existing Expansion Plan (16% RM Target)	New Expansion Plan (15% RM Target)
2016	14.7%	165 MW PPA	NA
2017	14.1%	165 MW PPA	NA
2018	12.5%	605 MW CCCT	605 MW CCCT

With the new 15% target RM, the 165 MW Power Purchase Agreements (PPAs) in 2016 and 2017 in the existing expansion plan could be avoided, resulting in an estimated cost savings of $9.6 M each year. However, the absence of the PPAs results in higher expected system production costs of approximately $0.2 M in both 2016 and 2017, as estimated by GP using PROSYM software.

4.2.2 Trade Benefits

The trade benefits of joining MISO or PJM were estimated by GP using PROSYM as lower native load production costs and higher off-system sales (OSS) margins that resulted from the following:

- Reducing the spinning reserve requirement from 230 MW to 100 MW
- Eliminating RTO expenses for OSS and purchases
- Eliminating 3rd party transmission expenses for purchases
- Eliminating LG&E-KU transmission expenses for OSS and purchases
- Eliminating $2 "costless adder" for OSS and purchases

The eliminated LG&E-KU transmission and $2 costless adder expenses were deducted from the total savings because they do not represent actual savings to the Companies. The PJM and MISO analyses used electricity price forecasts specific to each RTO.

- The resulting net trade benefits total between $11 M and $15 M annually over the study period for each RTO
- The present value of trade benefits is approximately $90 M for both PJM and MISO.

the new 15% RM target, a PPA would be chosen for years with RMs between 13% and 14%; permanent capacity would be chosen below 13%.

4.3 Other Components

4.3.1 Administrative charges

Both MISO and PJM have various tariff schedules to recover the administration cost of operating the markets and providing services to their respective footprints. For MISO, these costs were estimated using $/MWh cost projections contained in the MISO 2011 Budget presentation published on their website[8]. Administrative costs for PJM were estimated based upon the costs noted in the CRA study.

4.3.2 Transmission Revenue

Both MISO and PJM allocate third-party transmission revenues to the transmission owners in their respective footprints. MISO uses a formula based on allocation of plant in service and transmission flows to allocate transmission revenue. This allocation was assumed to be approximately $1 M per year to LKE, loosely based upon prior experience in MISO. The projected allocation to LKE from PJM was estimated using the PJM transmission revenues shown in the CRA study, multiplied by LKE's estimated proportion of PJM's total transmission revenue requirement, which calculated to be approximately 2.7%.

4.3.3 Uplift Costs

Both MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, for both RTOs, these costs are the result of committing units in real-time that were not committed in the day-ahead market. In MISO these costs are referred to as "revenue sufficiency guarantee" (RSG) costs and, in the PJM market, as "operating and balancing reserve cost". Both RTOs also have other sources of these "revenue insufficient" costs. For MISO, RSG cost was assumed to be a net zero for LKE, but a load ratio share of the historic Revenue Neutrality Uplift cost of $100 million per year was assumed.[9] For this analysis, the PJM allocation of these costs to LKE was assumed to be negligible, which is consistent with the CRA study.

4.3.4 FERC Charges

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as LKE is assessed outside of an RTO. For this analysis, the

[8] https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/BOD/2011/20111208/20111208%20BOD%20Item%2006%20%20VI.A%202012%20Budget%20Public%20Final.pdf

[9] Load ratio share roughly estimated based on LKE peak load of 7200 and total MISO peak load of ~107,000 or 6.6%

current FERC assessment charges were escalated for inflation and applied to LKE Energy for load as given in the 2013 Business Plan.

4.3.5 Net Zero Components

Two components, congestion cost/ARR/FTR and ancillary services market, have been identified that would be considered of net zero benefit. It is expected that the value of the ARR/FTR may equal or exceed the congestion costs; however, the net cost or benefit will not be known with certainly until such rights are issued. A company may choose to self-supply ancillary services and be no worse off than before joining an RTO. While there could be some potential benefit in the RTO market, there is no means to estimate the value of such benefit.[10]

4.3.6 Eliminated Administration Charges

Membership in either PJM or MISO would result in a re-alignment of internal cost for the provision of certain services. For the purposes of this analysis, it was assumed that LKE would no longer need the current Independent Transmission Operator (ITO) or Reliability Coordinator (RC) services provided by TranServ and TVA, respectively. There also likely would be a reduction in cost in the balancing authority services provided by internal staffing. This reduction would be offset to some degree by increases in internal staffing to manage the day to day operations in the RTO, as well as for back office settlement of the RTO statements and invoices on a daily basis.

4.3.7 De-Pancaking

LKE currently pays "depancaking" cost to certain entities as a result of the 2006 MISO exit.[11] It is assumed that all of these payments would cease if LKE were to join either PJM or MISO.

[10] See Charles River Associates EKPC RTO Membership Assessment (March 2012)

[11] LKE pays costs for certain entities to keep them from having to pay more for transmission now than when the Companies were in MISO, known as depancaking costs.

RTO Membership Analysis

5 MISO Summary

												Present Value Rate
												6.75%
Cost		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
	MISO Admin Cost ($M)	-11.3	-11.0	-11.0	-11.4	-11.8	-12.2	-12.6	-13.1	-13.5	-14.1	-85.4
	MISO MVP XM Expansion Cost ($M)	-5.9	-12.1	-20.7	-33.0	-37.9	-43.6	-51.1	-56.8	-55.9	-55.3	-241.3
	LKE Internal Staffing/Equipment Cost ($M)	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-3.9
	MISO Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MISO Misc. Uplift Cost ($M) - Revenue Neutrality Uplift	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-46.9
	MISO Ancillary Services Market ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MISO FERC Fees (Incremental of Present) ($M)	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.3	-13.0
	LKE Lost XM Revenue from 3rd Parties	-3.0	-3.1	-3.2	-3.2	-3.3	-3.4	-3.5	-3.6	-3.7	-3.7	-23.6
	Sum of Cost	-28.8	-34.8	-43.6	-56.6	-62.0	-68.3	-76.3	-82.7	-82.6	-82.7	-414.0
Benefits		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
	MISO XM Revenue Allocation ($M)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	7.1
	MISO Trade Benefits (Production Costs) ($M)	11.1	12.3	12.3	11.6	12.1	12.4	13.2	12.7	14.9	15.6	89.7
	MISO Operating Reserve Margin Capacity Benefits ($M)	0.0	0.0	0.0	9.4	9.3	0.0	0.0	0.0	0.0	0.0	13.9
	LKE Elimination of TVA RC Cost ($M)	2	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	15.7
	LKE Elimination of ITO Cost ($M)	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	23.6
	LKE Elimination of De-Pancaking ($M)	6.8	7.1	6.2	6.1	6.2	6.4	6.5	6.7	6.9	7.1	46.8
	LKE Elimination of TEE Group Admin Charge ($M)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
	Sum of Benefits	24.0	25.6	24.8	33.6	34.3	25.6	26.6	26.5	29.0	30.0	197.5
	Net of Cost + Benefits	-4.8	-9.2	-18.8	-23.0	-27.7	-42.7	-49.7	-56.2	-53.6	-52.7	-216.5

RTO Membership Analysis

6 PJM Summary

Present Value Rate 6.75%

Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
PJM Admin Cost ($M)	-11.4	-11.4	-11.6	-12.0	-12.4	-12.8	-13.2	-13.8	-14.2	-14.8	-89.3
PJM Backbone XM Expansion Cost ($M)	0.0	-12.6	-27.0	-27.0	-27.0	-27.0	-27.0	-40.4	-40.4	-40.4	-176.3
LKE Internal Staffing/Equipment Cost ($M)	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-3.9
PJM Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM Misc. Uplift Cost ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM Ancillary Services Market ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM FERC Fees (Incremental of Present) ($M)	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.3	-13.0
LKE Lost XM Revenue from 3rd Parties	-3.0	-3.1	-3.2	-3.2	-3.3	-3.4	-3.5	-3.6	-3.7	-3.7	-23.6
Sum of Cost	-16.4	-29.1	-43.9	-44.5	-45.1	-45.7	-46.3	-60.4	-61.1	-61.9	-306.0

Benefits	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
PJM XM Revenue Allocation ($M)	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9	1.9	12.0
PJM Trade Benefits (Production Costs) ($M)	12.6	12.9	11.7	10.9	11.3	12.2	13.0	14.2	14.6	15.2	90.2
PJM Reduced Operating Reserve Margin Capacity Benefits ($M)	0.0	0.0	0.0	9.3	9.4	0.0	0.0	0.0	0.0	0.0	13.9
LKE Elimination of TVA RC Cost ($M)	2	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	15.7
LKE Elimination of ITO Cost ($M)	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	23.6
LKE Elimination of De-Pancaking ($M)	6.8	7.1	6.2	6.1	6.2	6.4	6.5	6.7	6.9	7.1	46.8
LKE Elimination of TEE Group Admin Charge ($M)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Sum of Benefits	26.0	26.8	24.9	33.4	34.2	26.1	27.2	28.8	29.5	30.5	203.0
Net of Cost + Benefits	9.6	-2.3	-19.0	-11.2	-10.9	-19.6	-19.0	-31.6	-31.6	-31.3	-103.0

7 Additional Considerations and Uncertainties

7.1 NERC Compliance Requirements

Since the companies own and operate certain facilities used in interstate commerce or that have the potential to impact the bulk electric system, the Companies are required to comply with Reliability Standards for planning and operating the bulk electric system, as developed by the North American Electric Reliability Corporation (NERC). Under current operations, LG&E/KU Transmission Owner (TO) are responsible for over 1,200 NERC compliance requirements falling under the Reliability Standards. It is estimated that slightly over 300 of these requirements would be performed by an RTO and no longer an internal function if the companies were to join and RTO. While this reduction is noted qualitatively, the study does not estimate a financial cost/benefit related to compliance.

7.2 Regulatory Environments – MISO, PJM

There has been considerable realignment of RTO memberships since 2006. Examples include the departure from MISO of First Energy and Duke-Ohio. Both entities are now PJM transmission owning members. MISO has retained and, with the joining of Entergy, BREC, and Dairyland Power, gained members who operate in non-contestable load areas, while PJM has solidified membership of transmission owners operating in states that have retail access and unbundled utilities.[12] Given this realignment between MISO and PJM membership, it is likely that more of Kentucky's regulatory paradigm and LKE's traditional regulated utility business model would be accommodated in MISO versus PJM. For example, the entities within MISO that had been advocating for capacity markets are simply not as politically strong as they once may have been. Moreover, membership in PJM would almost certainly pit LKE interests against those of the traditional PPL companies on matters of significance to all concerned.

7.3 Future RTO Market/Program Implementation

The costs/benefits of "markets" or "programs" that each RTO may implement in the future are uncertain and so cannot be reflected in this analysis.

8 Conclusion

The results of this threshold analysis reveal that a more in depth study of the cost and benefits of RTO membership is not warranted at this time. Further, the study results confirm the prudency of LKE continuing with the establishment the Southeast Order 1000 Planning Region.

[12] Ameren-Illinois's continued membership in MISO being a notable exception.