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STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2014-0370

Jefferson City, Missouri
April 2, 2015

** **Denotes Highly Confidential Information** **

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I. Background of Kansas City Power & Light Company and Great Plains Energy Incorporated

Kansas City Power & Light Company ("KCPL" or the "Company") is a corporation duly organized and existing under the laws of the state of Missouri. KCPL is a regulated public utility operating in the states of Kansas and Missouri. It also provides wholesale electricity to several municipal customers under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). KCPL distributes and sells electric service to the public in its certificated areas in Kansas and Missouri, and is an "electrical corporation" and "public utility" subject to the jurisdiction, supervision, and control of the Missouri Public Service Commission ("Commission") under Chapters 386 and 393 of the Revised Statutes of Missouri. KCPL is wholly-owned by Great Plains Energy Incorporated ("Great Plains" or "GPE") and is an affiliate of KCP&L Greater Missouri Operations Company ("GMO," which was formerly known as Aquila, Inc. and before that UtiliCorp United, Inc.).[1] Like KCPL, GMO is an "electrical corporation" and "public utility" that is subject to the jurisdiction of the Commission. KCPL and GMO collectively operate and present themselves to the public under the brand and service mark "KCP&L." Great Plains is a public utility holding company regulated under the Public Utility Holding Company Act of 2005, which was enacted as part of the Energy Policy Act of 2005. Great Plains does not provide electric service to retail customers.

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1 KCPL and GMO became affiliates on July 14, 2008, when, after a Commission Order in Case No. EM-2007-0374 effective July 1, 2008, authorizing the acquisition; Great Plains acquired GMO, then known as Aquila, on July 14, 2008.

Approximate customer counts for total KCPL (Kansas and Missouri) from 2006 through 2014 follow:

Year	Total	Residential	Commercial	Industrial, Municipal and Other Electric Utilities
2014	520,700	459,000	59,600	2,100
2013	514,700	453,900	58,700	2,100
2012	511,800	451,500	58,200	2,100
2011	511,000	451,000	58,000	2,100
2010	510,000	450,000	58,000	2,000
2009	509,000	450,000	57,000	2,000
2008	509,000	449,000	58,000	2,000
2007	506,000	446,100	57,600	2,300
2006	505,000	446,000	57,000	2,200

Source: KCPL and Great Plains' 2006-2014 Annual Reports at page 9

KCPL's retail revenues make up approximately 87% of its total operating revenues over the last three years, with wholesale firm power, bulk power sales (non-firm off-system sales), and miscellaneous electric revenues making up the remainder of KCPL's total revenues.

To serve its current customers, KCPL owns total generating capacity of 4,493 megawatts—549 megawatts (MW) of nuclear capacity, 2,751 megawatts of coal capacity, 148 megawatts of wind capacity accredited at 46 megawatts, 772 megawatts of natural gas-fired combustion turbine capacity, 375 megawatts of oil-fired combustion turbine capacity, and it purchases additional megawatts of power [*Source*: Great Plains' 2014 Annual Report at page 23].

KCPL's actual 2013 fuel mix based on net megawatts generated and overall fuel costs, on a cents per net kilowatt-hour (kWh) generated basis, are:

Fuel Type	2014 Fuel Mix – Actual	2013 Fuel Mix – Actual	2015 Fuel cost in cents per net kWh generated--ESTIMATED	2014 Fuel cost in cents per net kWh generated--ACTUAL	2013 Fuel cost in cents per net kWh generated--ACTUAL
Coal	81%	85%	2.05	2.19	2.14
Nuclear	16	12	0.66	0.68	0.79
Natural gas and oil	1	1	7.75	10.79	9.41
Wind	2	2	----	----	----
Total	100%	100%	1.86	1.95	1.99

Source: 2013 Annual Shareholder Report—page 8 and 2014 Annual Shareholder Report—page 8

KCPL had 2,935 employees as of December 31, 2014. Those employees are responsible for all work for Great Plains and the GMO operations through an operating agreement. Of these, 1,838 employees are represented by three local labor unions of the International Brotherhood of Electrical Workers ("IBEW"). The local labor unions and when each labor agreement expires are:

Labor Union	Representing	Labor Agreements Expire
Local 1613	Clerical Workers	March 31, 2018
Local 1464	Transmission & Distribution Workers	January 31, 2016
Local 412	Power Plant Workers	February 28, 2018

S*ource*: KCPL and Great Plains' 2013 Annual Report at page 9

This rate case, Case No. ER-2014-0370, is KCPL's second general electric rate case after completing Iatan Unit 2 and is referred to in this report as KCPL's 2015 rate case. Iatan Unit 2 is an 850 megawatt total unit, coal-fired, generating unit KCPL built during, and as contemplated in, KCPL's Experimental Alternative Regulatory Plan (the "Regulatory Plan"), the Commission approved on July 28, 2005, in Case No. EO-2005-0329.

During the Regulatory Plan, as contemplated in the plan, KCPL filed four general rate increase cases to address the economic impacts on KCPL for the major environmental upgrades to its La Cygne Unit 1 and Iatan Unit 1 generating units, and the construction of Iatan Unit 2—its new baseload, 850 megawatt coal-fired, generating unit. KCPL invested in 100 megawatts of wind-generated capacity in September 2006 with phase one of its Spearville Wind Farm and later, after exploring the addition of a second 100 megawatts of wind-generated capacity, added another 48 megawatts (accredited 4 megawatts) of wind capacity—Spearville 2 Wind Energy Facility—in 2010. KCPL filed the four general rate increases relating to the Regulatory Plan on February 1, 2006 (Case No. ER-2006-0314 herein referred to as the "2006 rate case"), February 1, 2007 (Case No. ER-2007-0291, herein referred to as the "2007 rate case"), September 8, 2008 (Case No. ER-2009-0089, herein referred to as the "2009 rate case") and June 4, 2010 (Case No. ER-2010-0355, herein referred to as the "2010 rate case"), respectively. In the 2010 rate case the Commission found that as of August 26, 2010, Iatan Unit 2 was fully operational and used for service. In addition to the above rate cases filed under the Regulatory

Plan, KCPL also filed for a rate increase on February 27, 2012, (Case No. ER-2012-0174, herein referred to as the "2012 rate case").

On April 4, 2007, Great Plains, KCPL, and Aquila, filed a joint application with the Commission, designated as Case No. EM-2007-0374 requesting approval for a series of transactions which ultimately would result in Great Plains acquiring Aquila's Missouri electric and steam operations, as well as its merchant services operations. The Commission approved the request of Great Plains, KCPL, and Aquila in an Order effective July 1, 2008. Great Plains acquired Aquila on July 14, 2008, and later in 2008, Aquila changed its name to KCP&L Greater Missouri Operations Company.

Staff Expert/Witness: Cary G. Featherstone

II. Executive Summary

In response to KCPL's October 30, 2014, application to increase its retail rates to recover an additional approximately $120.9 million per year from its Missouri retail customers—an expected 15.75% increase in rates -- Staff reviewed all of the revenue requirement cost of service components (capital structure and return on investment; rate base investment and income statement results, including revenues; operating and maintenance expenses; depreciation expense; and related taxes, including income taxes) which comprise KCPL's revenue requirement. The results of that review are presented in this Report, including Staff's separately filed Schedules and Accounting Schedules. The members of Staff who participated in that review are identified in the sections of the Report where their narrative testimony explains what they did, opinions and their results. In the contemporaneously filed separate question and answer formatted testimony of Cary G. Featherstone of the Utilities Services Department, Staff presents its recommended revenue requirement resulting from the analysis and recommendations described in this Report, as well as an overview of this Report.

Staff recommends a return on equity (ROE) range of 9.00% to 9.50%, with a mid-point of 9.25%, which yields the rate of return range of 7.28% to 7.53%. Staff's KCPL revenue requirement calculation, which is based on KCPL's actual costs through December 31, 2014, indicates a shortfall of between $17.4 to $26.3 million based on current KPCL rates, which generate approximately $762.6 million of revenue for KCPL annually. With the increase of between $17.4 to $26.3 million (2.28% to 3.4%), Staff's total KCPL revenue requirement recommendation is approximately $780 to $788.9 million (per year). Because of changes expected for the true-up items through May 31, 2015, that are not known and measurable at this time, the Staff's revenue requirement for KCPL will change when the true-up process is completed in this case.

As part of its review of KCPL's proposed change in rates, Staff also examined the Additional Amortizations from the Regulatory Plan, and their treatment in this rate case based on the agreement reached in KCPL's 2010 case, Case No. ER-2010-0355.

Staff anticipates there will be significant additional plant cost for La Cygne Unit 1 and Unit 2 environmental upgrades and for the replacement of Wolf Creek's essential water supply through the May 31, 2015, true-up cut-off in this case, as well as cost increases in payroll and payroll-related benefits such as pensions and medical costs. Fuel prices will also be examined for any changes as part of the true-up process.

The following is a non-exhaustive list of cost drivers affecting KCPL's revenue requirements that are discussed in this report:

- Rate of Return;
- KCPL's ownership share of costs for new environmental equipment installed at La Cygne Units 1 and 2 expected to be completed in the 2nd quarter 2015, and included in the May 31, 2015 true-up;
- KCPL's ownership share of costs for upgrades at Wolf Creek relating to the essential water supply expected to be completed in 2nd quarter 2015, and included in the May 31, 2015 true-up;
- KCPL's fuel costs, including freight rate changes and purchased power costs;
- KCPL's transmission costs;
- KCPL's cost increases for payroll;
- KCPL's off-system sales margins from the firm and non-firm bulk power markets;
- KCPL's pension and other post-employment benefits (OPEBs) costs; and
- KCPL's cost increases for property taxes.

Staff Expert/Witness: Cary G. Featherstone

III. Kansas City Power & Light Company's Rate Case Filing

KCPL filed its general rate increase case on October 30, 2014, reflecting an annual increase in Missouri retail rate revenues of $120.9 million, a 15.75% increase. The Commission designated this rate case as Case No. ER-2014-0370. KCPL requested a rate of return on equity of 10.3% applied to a capital structure with 50.36% equity based on Great Plains' overall capital structure [paragraphs 7 and 8 KCPL's Application- Minimum Filing Requirements page 3].

Unlike the last three previous KCPL rate cases, dating back to when Great Plains acquired GMO, GMO did not at the same time file a rate increase case for its electric operations. GMO charges different customer rates in two different geographical areas – one in and about Kansas City, which was formerly served under the d/b/a Aquila Networks - MPS and one about St. Joseph, Missouri, which was formerly served under the d/b/a Aquila Networks – L&P. For ease, the areas with differing rates are referenced as "MPS" and "L&P," regardless of the entity serving them.

On January 2, 2015, KCPL filed for an increase in its Kansas rates. That case is designated as Docket No. 15-KCPE-116-RTS, and KCPL is requesting a $67.3 million increase based on a test year of June 30, 2014, adjusted for known and measurable changes. This is a 12.53% increase over the current level of Kansas revenues of $536.7 million. KCPL's request in Kansas is based on a ROE of 10.3% and a 50.48% equity capital structure, which result in a 7.94% total return on investment [paragraphs 3 and 11 KCPL's Kansas Application pages 2 and 5—Docket No. 15-KCPE-116-RTS].

Staff Expert/Witness: Cary G. Featherstone

A. Test Year

As the Commission ordered on December 12, 2014, the test year in this case is the 12-month period ending March 31, 2014, updated for known and measurable changes through December 31, 2014, and trued-up through May 31, 2015. Staff's revenue requirement presented in its Accounting Schedules filed with this report is the test year as updated and includes preliminary estimates for expected changes as of the true-up cut-off date of May 31, 2015, based on currently available information.

Staff Expert/Witness: Cary G. Featherstone

B. True-up Case

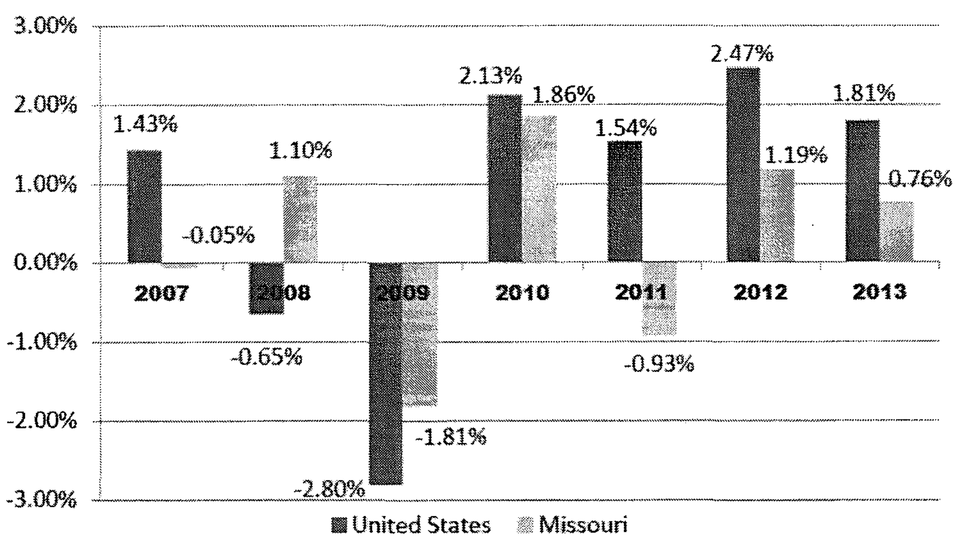
Because of anticipated cost increases, including the cost of plant additions relating to the environmental upgrades being installed at La Cygne Units 1 and 2, and the essential water system at Wolf Creek, at KCPL's request the Commission established a true-up through the May 31, 2015.

Staff Expert/Witness: Cary G. Featherstone

IV. Economic Considerations

Missouri's general economic condition, specifically of the counties[2] that compose the service area of KCPL, continues to experience challenges in the wake of the recession from December 2007 to June 2009. Figure 1 below shows that the real gross domestic product ("GDP") growth of Missouri has been smaller than the United States as a whole since the recession ended (2009), and was even negative for Missouri in the year 2011. GDP data for 2014 will not be available until June, but preliminary national data indicates that the national GDP grew 2.4% on an annual basis.

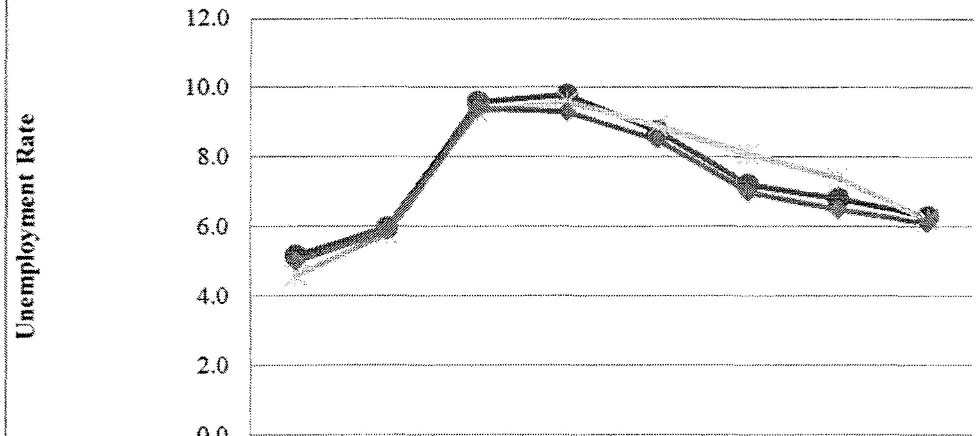
Figure 1: Real GDP Growth 2007-2013 (Percent)



[2] According to Appendix 3 of KCPL's application, which includes the minimum filing requirements, and KCPL's current tariff, KCPL serves a total of 13 counties.

As seen in Figure 2 below, the annual unemployment levels are still above the pre-recession levels. The unemployment rates for 2014 appear to show the Missouri unemployment rate leveling-off near six percent and the national trend continuing a downward trajectory. The combined unemployment rate for all of the counties that KCPL serves tends to be 0.2 to 0.3 percent less than Missouri's unemployment rate.[3]

Chart 2: Comparison of Unemployment Rates For KCPL Service Area



	2007	2008	2009	2010	2011	2012	2013	2014
KCPL	5.2	6.0	9.6	9.8	8.8	7.2	6.8	6.3
United States	4.6	5.8	9.3	9.6	8.9	8.1	7.4	6.2
Missouri	5.0	5.9	9.4	9.3	8.5	7.0	6.5	6.1

The employment numbers from the Bureau of Labor and Statistics show that the number of jobs in KCPL's service territory, which peaked in 2008, is still below 2004 levels, but has increased every year since 2010 (Figure 3). Information for 2014 is not expected to be released until June 2015.

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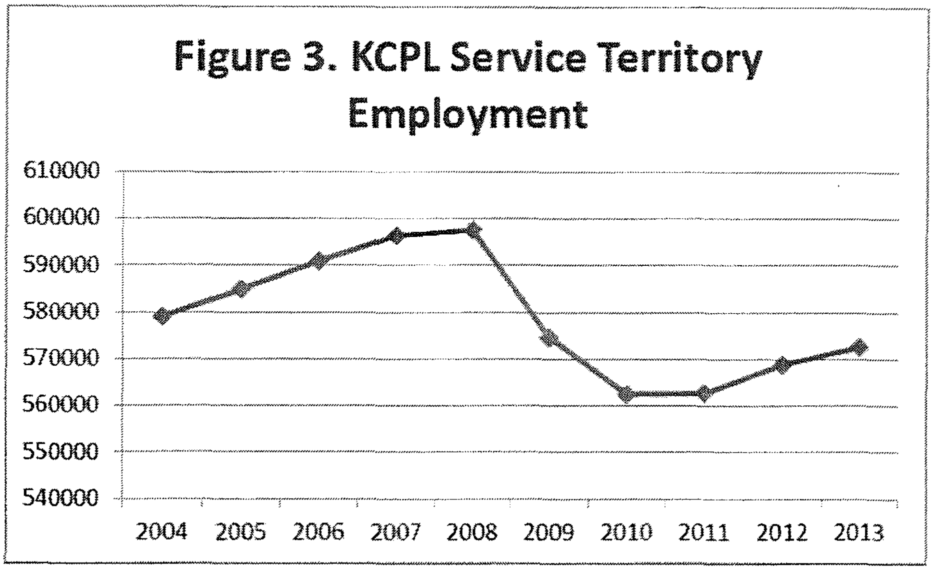
[3] The county level unemployment data is unavailable for 2014. KCPL's unemployment rate for 2014 is estimated from the trend with the unemployment rate of Missouri.



The current economic outlook from a variety of economic forecasters suggests that employment, household income, and GDP will continue to improve for the short term. Specifically, the most recent version of Business Cycle Conditions from the American Institute for Economic Research ("AIER")[4] rated the majority of leading indicators,[5] all coincident indicators, and a majority of lagging indicators[6] as expanding or probably expanding, which suggests a recession is unlikely in the next six to twelve months.[7] The leading indicators have weakened over the last couple of months but remain above 50 percent which indicates economic expansion is likely over the next couple of quarters.[8] One leading indicator in particular, the spread between the interest rates of the 3-Month and 10-Year Treasury bills, has correctly anticipated the last four recessions when the interest rate of the 3-Month Treasury bill was greater than the interest rate of the 10-Year Treasury bill. Currently the 10-Year Treasury bill rate is greater than the 3-Month Treasury bill

[4] American Institute for Economic Research. (24FEB15). "Business Conditions Monthly." https://www.aier.org/bcmoverviewfeb2015 (11MAR15).

[5] AIER uses twelve leading indicators, which are a measurable economic factor that tend to change before the economy starts to follow a particular pattern or trend, including M1 money supply, new housing permits, initial claims for unemployment insurance, an index of common stock prices, and a three-month percent change in consumer debt.

[6] AIER uses six coincident indicators, including nonagricultural employment, real GDP, and personal income less transfer payments; and six lagging indicators, including the average duration of unemployment, a composite of short-term interest rates, and manufacturing and trade inventories. Coincident indicators are measurable economic factors that tend to change at the same time as a change in the economy and lagging indicators tend to change after the economy has change.

[7] This outlook is for the broad U.S. economy in general and may not reflect the outlook in any specific sector.

[8] American Institute for Economic Research. (24FEB15). "Business Conditions Monthly." https://www.aier.org/bcmoverviewfeb2015 (11MAR15), p. 3.

rate. The rate of the 10-Year Treasury bill has recovered from a low of 1.68 percent at the beginning of February and is now fluctuating around two percent while the 3-Month Treasury bill rate continues to remain around a few hundredths of a percent from zero.

Figure 4, below, provides a comparison of the increase in average weekly wages for the counties in the KCPL service area, Consumer Price Index ("CPI"), Producer Price Index ("PPI")[9], and KCPL's electric rates. From 2007 to 2013, the counties in the KCPL service area collectively experienced an 11.47% increase in average weekly wages. This was slightly lower than the overall Missouri compounded increase in average weekly wages of 11.56% and about 1% below the CPI increase. During that same time period, electric rates for residential customers served by KCPL increased, in Case Nos. ER-2006-0314, ER-2007-0291, ER-2009-0089, ER-2010-0355, and ER-2012-0174, a cumulative total of 57.69% which accumulated to a total increase of approximately $283.1 million per year, shown in Table 1. However, KCPL has also experienced inflationary pressure illustrated by a 17.84% increase in the PPI for Industrial Commodities from 2007 to 2013.[10] KCPL is currently requesting an additional $120.9 million per year or a 15.75% increase in rates. From 2007 to 2013, the increase in average weekly wages for counties in the KCPL service area is less than one-fifth of the increase in electric rates for KCPL customers. If KCPL receives its requested 15.75% increase, the increase in average weekly wages would be less than one-seventh of the increase in electric rates, but this does not include any increase in average weekly wages for 2014 and 2015 which are currently unavailable.

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[9] The PPI represents the Producer Price Index for Industrial Commodities which includes textile products and apparel, hides, skins, leather and related products, fuels and related products and power, chemicals and allied products, rubber and plastic products, lumber and wood products, pulp, paper and allied products, metals and metal products, machinery and equipment, furniture and household durables, nonmetallic mineral products and transportation equipment.

[10] Detailed information on KCPL's expenditures and revenues can be found later in this Report.

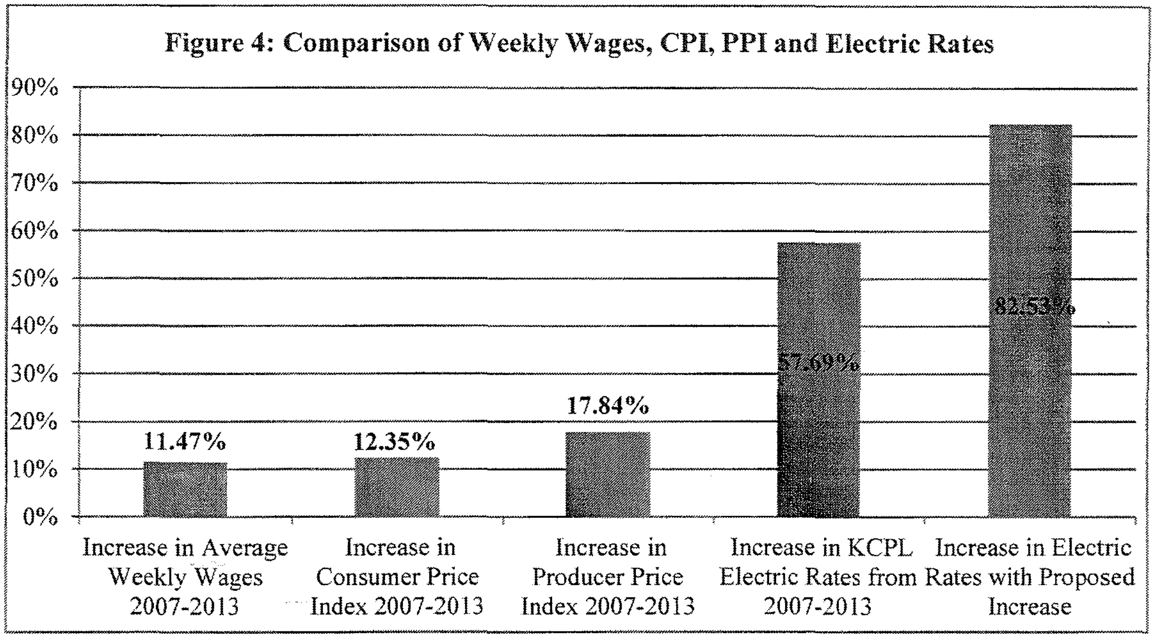

Table 1: KCPL Rate Case History 2007 - 2015

Case Number	Effective Date	Dollar Value	Percent Increase
ER-2006-0314	1-Jan-07	$50,616,638	10.46%
ER-2007-0291	1-Jan-08	$35,308,914	6.50%
ER-2009-0089	1-Sep-09	$95,000,000	16.16%
ER-2010-0355	4-May-11	$34,817,199	5.25%
ER-2012-0174	26-Jan-13	$67,390,893	9.64%
Total Dollars		$283,133,644	
Total Compounded Increase			57.69%
ER-2014-0370	(Proposed)	$120,900,000	15.75%
Total with Proposed		*$404,033,644*	*82.53%*

Lastly, according to the 2009 Residential Energy Consumption Survey, the most recent survey available by the U.S. Department of Energy- Energy Information Administration, Missouri households consume about 12% more energy than the U.S. average. However, the historically lower residential electricity prices result in the average Missouri household paying slightly less for energy than the national average. Overall, the median Missouri household spends about 2.37% of its income on electricity. For households that were identified as being at or below the 150% poverty line, the median increased to 7.68%.

Staff Expert/Witness: Michael L. Stahlman

V. Kansas City Power & Light Company Electric Rates

KCPL has filed for the following rate increases under the Regulatory Plan for the period from 2006 to 2010 and a rate increase in 2012:

Case No.	Date Filed	Amount Requested	Amount Authorized	Effective Date of Rates
ER-2006-0314	February 1, 2006	$57 million 11.5% increase	$50.6 million	January 1, 2007
ER-2007-0291	February 1, 2007	$45 million 8.3% increase	$35.3 million	January 1, 2008
ER-2009-0089	September 5, 2008	$101 million 17.5% increase	$95 million 16.2% increase	September 1, 2009
ER-2010-0355	June 4, 2010	$92.1 million 13.8% increase	$34.8 million 5.23% increase	May 4, 2011
ER-2012-0174	February 27, 2012	$105.7 million 15.1% increase	$67.4 million	January 26, 2013
ER-2014-0370	October 30, 2014	$120.9 million 15.75% increase	Pending	September 2015 expected

KCPL had not had a general rate increase case prior to the 2006 rate case since the Wolf Creek rate case filed as Case No. EO-85-185. Since the 1985 Wolf Creek rate case, and the phase-in of rates relating to this nuclear generating unit, there have been several rate reductions as result of Staff earnings reviews. The following table identifies the rate activity for KCPL after Wolf Creek was placed in rates in April 1986 through the 2006 rate case filing:

Order Date	Case Number	Original Rate Request	Commission Decision
April 23, 1986	EO-85-185	$194.7 million	$78.3 million
April 1, 1987	EO-85-185	Not Applicable	$7.7 million
May 5, 1988	EO-85-185	Not Applicable	$8.5 million
December 29, 1993	ER-94-197	Not Applicable	($12.5 million)
July 3, 1996	EO-94-199	Not Applicable	($9.0 million)
October 7, 1997	EO-94-199	Not Applicable	($11.0 million)
April 13, 1999	ER-99-313	Not Applicable	($15.0 million)

Staff did a comparison of KCPL's electric rates in Missouri with other electric utilities in Missouri and Kansas. Based on information supplied by KCPL to the Edison Electric Institute ("EEI") that KCPL in turn provided in response to Staff data request, the composite average rates KCPL charges its Missouri customers overall are below the national average, and generally below those of other Kansas utilities and other mid-western utilities, but above the Missouri average. KCPL is in the region known as the West North Central in the EEI comparison. Besides Missouri and Kansas utilities, the West North Central region also includes Iowa, Minnesota, North Dakota and South Dakota utilities. On average, since KCPL started filing rate cases in 2006, its overall rates are above the average for the West North Central region beginning in 2010—prior to 2010 KCPL's overall rates were below the West North Central region:

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MISSOURI AND KANSAS TOTAL RATES – in cents per kWh hour									
Utility Company	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**
MISSOURI RETAIL AVERAGE RATES									
KCPL-Missouri	**8.78 cents/kWh** Jan 26, 2013 ER-2012-0174	**8.23**	**8.01** May 4, 2011 ER-2010-0355	**7.69**	**6.88** Sept 1 ER-2009-0089	**6.51** Feb 1 ER-2007-0291	**6.14** Feb 1 ER-2006-0314	**5.66**	**5.65**
MPS	9.51	9.48	9.31	9.09	8.36	7.79	7.33	6.85	6.45
L&P	9.10	8.49	7.34	6.75	6.34	5.93	5.63	5.30	5.20
Ameren Missouri	8.12	7.36	7.16	6.48	5.95	5.43	5.46	5.43	5.49
Empire-Missouri	10.65	10.35	10.07	8.96	8.45	8.18	8.03	7.33	7.09
Missouri Average	**8.58**	**7.96**	**7.72**	**7.11**	**6.55**	**6.04**	**5.93**	**5.74**	**5.71**
West North Central	8.56	8.06	7.82	7.53	7.14	6.81	6.51	6.38	6.17
United States Average	**10.37**	**10.09**	**10.09**	**9.97**	**9.83**	**9.77**	**9.20**	**8.89**	**8.22**
KANSAS RETAIL AVERAGE RATES									
KCPL-Kansas	10.42	9.87	9.43	8.57	8.06	7.46	6.73	6.35	6.32
Empire - Kansas	10.15	10.48	10.11	9.25	8.41	8.69	8.61	8.06	6.54
Westar Energy -- KGE	8.87	8.42	7.90	7.46	7.13	6.32	5.73	6.04	6.03
Westar Energy -- KPL	9.42	8.99	8.28	8.15	7.82	6.92	6.06	6.25	5.58
Kansas Average	9.46	9.00	8.43	8.00	7.62	6.84	6.12	6.35	6.14

Source: EEI Winter 2010 Report, page 180 provided in KCPL's response to Staff Data Request No. 0380- ER-2010-0355.
EEI Winter 2012 Report, page 180 provided in KCPL's response to Staff Data Request No. 0241- ER-2012-0174.
EEI Winter 2014 Report, page 179.

Based on information supplied by KCPL to EEI that KCPL in turn provided in response to Staff data requests, the rates KCPL charges its Missouri residential customers are below the national average and generally below those of the mid-western utilities, but above the Missouri average residential rate. KCPL's Missouri residential rates are higher than the L&P residential rates, but lower than the MPS residential rates.

The following table shows such a comparison of KCPL's actual residential customer rates as of January 1, 2014:

MISSOURI AND KANSAS RESIDENTIAL RATES – in cents per kWh hour									
Utility Company	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**
MISSOURI RESIDENTIAL RATES									
KCPL-Missouri	**10.82 cents/kWh**	**10.30**	**9.90**	**9.53**	**8.51**	**8.14**	**7.61**	**6.90**	**6.88**
MPS	11.17	11.21	10.81	10.52	9.67	9.10	8.64	8.08	7.45
L&P	10.81	10.24	8.64	7.97	7.43	7.03	6.78	6.31	5.97
Ameren Missouri	10.11	9.30	8.80	7.82	7.03	6.53	6.60	6.60	6.52
Empire-Missouri	11.90	11.74	11.22	9.95	9.75	9.19	9.10	8.35	7.98
Missouri Average	**10.50**	**9.89**	**9.39**	**8.54**	7.77	**7.27**	**7.18**	**6.96**	**6.77**
West North Central	10.82	10.35	9.91	9.40	8.79	8.37	8.13	7.99	7.70
United States Average	**12.43**	**12.20**	**12.07**	**12.01**	**11.72**	**11.53**	**10.95**	**10.62**	**9.60**
KANSAS RESIDENTIAL RATES									
KCPL- Kansas	11.57	11.09	10.58	9.67	9.07	8.43	7.43	6.92	6.88
Empire - Kansas	10.72	11.03	10.53	9.65	8.97	9.26	9.20	8.69	7.11
Westar Energy -- KGE	11.16	10.68	9.92	9.46	8.84	7.84	7.29	7.72	7.74
Westar Energy -- KPL	11.18	10.70	9.93	9.55	9.17	8.07	7.16	7.36	6.69
Kansas Average	11.29	10.81	10.12	9.56	9.03	8.12	7.31	7.51	7.27

Source: EEI Winter 2010 Report, page 212 provided in KCPL's response to Staff Data Request No. 0380- ER-2010-0355.
EEI Winter 2012 Report, page 212 provided in KCPL's response to Staff Data Request No. 0241- ER-2012-0174.
EEI Winter 2014 Report, page 212.

As shown in the table below, KCPL's Missouri commercial rates are below the national average and below those of other mid-western utilities, but higher than the Missouri average commercial rate.

KCPL's commercial rates in Missouri are now below the MPS and L&P commercial rates, but for several years they were higher than the L&P commercial rates, but lower than the MPS commercial rates:

MISSOURI and KANSAS COMMERCIAL RATES – in cents per kWh hour									
Utility Company	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**
MISSOURI COMMERCIAL RATES									
KCPL-Missouri	**8.37 cents/kWh**	**7.79**	**7.62**	**7.31**	**6.56**	**6.22**	**5.92**	**5.49**	**5.48**
MPS	8.57	8.49	8.45	8.25	7.62	7.08	6.59	6.16	5.94
L&P	9.12	8.46	7.36	6.69	6.26	5.86	5.51	5.26	5.37
Ameren Missouri	7.81	7.02	6.92	6.29	5.71	5.34	5.34	5.32	5.29
Empire- Missouri	10.58	10.25	9.94	8.82	8.60	8.13	7.96	7.32	7.08
Missouri Average	**8.20**	**7.55**	**7.40**	**6.85**	**6.26**	**5.87**	**5.74**	**5.56**	**5.50**
West North Central	8.60	8.07	7.83	7.50	7.01	6.75	6.51	6.38	6.17
United States Average	**10.52**	**10.19**	**10.20**	**10.21**	**10.03**	**10.05**	**9.53**	**9.33**	**8.54**
KANSAS COMMERCIAL RATES									
KCPL- Kansas	9.44	8.93	8.38	7.57	7.20	6.62	6.13	5.90	5.87
Empire - Kansas	11.18	11.59	11.21	10.27	9.48	9.62	9.61	9.19	7.64
Westar Energy -- KGE	8.95	8.46	7.97	7.57	7.31	6.66	6.03	6.38	6.29
Westar Energy -- KPL	8.90	8.45	7.99	7.64	7.33	6.54	5.68	5.89	5.22
Kansas Average	9.08	8.61	8.12	7.61	7.30	6.61	5.93	6.24	5.96

Source: EEI Winter 2010 Report, page 246 provided in KCPL's response to Staff Data Request No. 0380- ER-2010-0355.
EEI Winter 2012 Report, page 244 provided in KCPL's response to Staff Data Request No. 0241- ER-2012-0174.
EEI Winter 2014 Report, page 245.

The table below shows KCPL's Missouri industrial rates are now higher than the L&P industrial rates, but lower than the MPS industrial rates, KCPL's Missouri industrial rates are above the Missouri average and, since 2010 they are higher than those of other mid-western utilities. KCPL's Missouri industrial rates are still below the United States national average as of January 1, 2014.

MISSOURI AND KANSAS INDUSTRIAL-in cents per kWh hour									
Utility Company	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**
MISSOURI INDUSTRIAL RATES									
KCPL-Missouri	**6.46 cents/kWh**	**5.99**	**5.83**	**5.57**	**5.13**	**4.77**	**4.47**	**4.21**	**4.23**
MPS	6.40	6.27	6.28	6.26	5.82	5.34	4.89	4.58	4.49
L&P	6.96	6.47	5.61	5.16	4.96	4.60	4.26	3.98	3.97
Ameren Missouri	5.45	4.85	4.87	4.46	4.30	3.87	3.89	3.96	4.05
Empire-Missouri	8.07	7.72	7.72	6.89	6.60	6.19	6.08	5.51	5.41
Missouri Average	**5.88**	**5.35**	**5.30**	**4.90**	**4.73**	**4.26**	**4.18**	**4.14**	**4.61**
West North Central	6.10	5.68	5.62	5.48	5.38	5.21	4.83	4.76	4.52
United States Average	**6.91**	**6.60**	**6.64**	**6.71**	**6.63**	**6.66**	**6.15**	**6.00**	**5.62**
KANSAS INDUSTRIAL RATES									
KCPL- Kansas	8.16	6.65	7.95	7.06	6.73	6.15	5.50	5.15	5.15
Empire - Kansas	7.92	8.25	8.26	7.42	7.01	6.97	6.94	6.32	5.02
Westar Energy -- KGE	6.63	6.30	5.89	5.47	5.34	4.78	4.17	4.36	4.32
Westar Energy -- KPL	7.45	7.14	6.84	6.50	6.31	5.62	4.83	5.01	4.40
Kansas Average	7.00	6.62	6.34	5.91	5.75	5.15	4.49	4.77	4.65

Source: EEI Winter 2010 Report, page 278 provided in KCPL's response to Staff Data Request No. 0380- ER-2010-0355.
EEI Winter 2012 Report, page 276 provided in KCPL's response to Staff Data Request No. 0241- ER-2012-0174.
EEI Winter 2014 Report, page 278.

The above rates represent information supplied to Edison Electric Institute by electric utilities for publication entitled *EEI Typical Bills and Average Rate Report – Winter 2014*. Each utility who participates in the survey supplies information on its rates to EEI. The above rates relate to actual composite rates determined using actual revenue and kilowatt hour usage as of December 31 of a given year. As a cautionary note, these actual composite rates should not be confused with rates appearing in the tariff sheets of a utility. Also, while the commercial and industrial classes are used in federal filings, such as with the Securities Exchange Commission and FERC annual reports, these classifications do not reflect the categories of customer classes found in the tariffs of the Missouri companies. On KCPL's tariffs, industrial customers are large electric users.

Staff Expert/Witness: Cary G. Featherstone

VI. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula is the rate of return (ROR), which is usually premised on the goal of allowing a utility the opportunity to recover the costs required to secure debt and equity financing. If the allowed ROR is based on the costs to acquire capital, then it is synonymous with the utility's weighted average cost of capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis.

Staff's expert financial analyst, Zephania Marevangepo, has estimated the cost of equity for KCPL, a subsidiary of Great Plains, by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies (proxy group). Staff then compared that cost of common equity to Staff's cost of common equity estimate in KCPL's last rate case to determine what, if any, changes should be made to KCPL's previously allowed return on common equity (ROE). To the extent Staff's comparison showed a relative change in the cost of equity since the Commission's last authorized ROE for KCPL, Staff recommends the Commission change the level of the allowed ROE by a similar amount.[11]

[11] The cost of common equity is the return required by investors, determined by expert analysis of market data relating to a carefully-constructed group of proxy companies. The allowed return on equity ("ROE"), on the other

Staff's analysis shows that KCPL's cost of equity, as measured by Staff's selected proxy group, has declined by at least 25 to 75 basis points. The cost of equity decline implies that an allowed ROE of 9.00% to 9.50% would be appropriate for KCPL. Consequently, Staff recommends the Commission set KCPL's allowed ROR based on an allowed ROE of 9.00% to 9.50%, mid-point 9.25% (as of the December 31, 2014 update period). The details of the capital structure and the return components are detailed in the following table:

			Allowed Rate of Return Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	9.00%	**9.25%**	9.50%
Common Stock Equity	50.31%	—	4.53%	**4.65%**	4.78%
Preferred Stock	0.55%	4.29%	0.02%	0.02%	0.02%
Long-Term Debt	49.14%	5.55%	2.73%	**2.73%**	2.73%
Total	**100%**		7.28%	**7.41%**	7.53%

The details of Staff's analysis and recommendations are presented in Schedules 1-18 in Appendix 2. Staff's workpapers will be provided to the parties at the time of filing Staff's Cost of Service Report. Staff will make any source documents of specific interest available upon the request of any party to this case or upon the Commission's request.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory and by certain minimum Constitutional standards. Investor-owned public utilities such as KCPL are private property that the state may not confiscate without appropriate compensation. The Constitution requires, therefore, that utility rates set by the government must allow a reasonable opportunity for the shareholders to earn a fair return on their investment. The United States Supreme Court has described the minimum characteristics

hand, is the value selected by the Commission for use in calculating a utility's forward-looking rates for implementation at the end of the rate case.

of a Constitutionally-acceptable rate of return in two frequently-cited cases.[12] In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:[13]

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co.*, the Court stated:[14]

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

From these two decisions, Staff derives and applies the following principles to guide it in recommending a fair and reasonable ROR:

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[12] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943); *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, ***43 S.Ct. 675, 67 L.Ed. 1176*** (1923).

[13] 262 U.S. at 692-693, 43 S.Ct. at 679, 67 L.Ed. at 1176, 1182-83.

[14] 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.

1. A return consistent with returns of investments of comparable risk;

2. A return sufficient to assure confidence in the utility's financial integrity; and

3. A return that allows the utility to attract capital.

Embodied in these three principles is the economic theory of the opportunity cost of investment. The opportunity cost of investment is the return that investors forego in order to invest in similar risk investment opportunities that vary depending on market and business conditions.

The methodologies of financial analysis have advanced greatly since the *Bluefield* and *Hope* decisions.[15] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return KCPL's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific Discounted Cash Flow (DCF) method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[16] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for KCPL.

In this case, Staff has applied this comparable company approach through the use of both the DCF method and the Capital Asset Pricing Model (CAPM). Properly used and applied in

[15] Neither the Discounted Cash Flow (DCF) nor the Capital Asset Pricing Model (CAPM) methods were in use when those decisions were issued.

[16] Because the DCF method uses stock prices to estimate the cost of equity, this theory not only compares the utility investment to other utilities, but it compares the utility investment to all available assets. Consequently, setting the allowed ROE based on a market-determined cost of equity is necessarily consistent with the principles of *Hope* and *Bluefield*.

appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity based on the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***. However, as Staff will discuss extensively throughout this section of the report, Staff believes it is common practice for commissions to allow returns on equity that are higher than the costs of equity for utilities. Consequently, Staff's recommended allowed ROE is higher than Staff's estimate of KCPL's cost of equity.

Because the Commission authorized an ROE in KCPL's last rate case that it deemed to be fair and reasonable, Staff believes it can best serve the Commission by providing it an estimate of the relative change in electric utilities' cost of equity in general, and KCPL's in particular, since KCPL's last rate case, Case No. ER-2012-0174. Staff believes the cost of equity has declined since KCPL's last rate case. Consequently, Staff recommends the Commission allow KCPL a ROE in a range of 9.00 to 9.50 percent with a point estimate of 9.25 percent.

C. Current Economic and Capital Market Conditions

Determining whether a cost of capital estimate is fair and reasonable requires a good understanding of the current economic and capital market conditions, with the former having a significant impact on the latter. With this in mind, Staff emphasizes that an estimate of a utility's cost of equity should pass the "common sense" test when considering the broader current economic and capital market conditions.

1. Economic Conditions

Although the economy contracted in the first quarter of 2014, it grew fairly rapidly in the second and third quarters, before it slowed slightly in the fourth quarter. Real Gross Domestic Product ("GDP") contracted by 2.1 percent in the first quarter, increased 4.6 percent in the second quarter, increased 5.0 percent in the third quarter and increased 2.6 percent in the fourth quarter.[17] Bureau of Economic Analysis (BEA) economists attributed the deceleration in the

[17] http://www.bea.gov/national/index.htm#gdp. "Real" GDP is adjusted to reflect inflation.

fourth quarter to a downturn in federal government spending, decelerations in both nonresidential fixed investment and net exports. As of December 2014, the Federal Reserve Board Members and the Federal Reserve Bank Presidents projected real GDP would grow between 2.6% and 3.0% in 2015, 2.5% to 3.0% in 2016, and 2.3% to 2.5% in 2017. The longer run projections for real GDP growth were between 2.0 to 2.3%. These projections were revised down at the March 18, 2015 meeting. The Federal Reserve Chairwoman, Janet Yellen, attributed the downward revision, in part, to the decline in export growth due to the strength of the U.S dollar. She also indicated that incoming data indicates that the current real economic growth rate has come down from levels that were experienced in the last several quarters. As of March 18, 2015, the Federal Reserve Board Members and the Federal Reserve Bank Presidents projected real GDP would grow between 2.3% and 2.7% in 2015, 2.3% to 2.7% in 2016 and 2.0% to 2.4% in 2017. The longer run projections for real GDP growth were between 2.0 to 2.3%.[18]

Information released from the recently held Federal Open Market Committee (FOMC) meeting held on March 18, 2015, shares the FOMC's intention regarding any future changes in the Federal Funds Rate. The following excerpt from the FOMC's press release provides direct comments from the FOMC regarding its views:

> Information received since the Federal Open Market Committee met in December suggests that economic activity has been expanding at a solid pace. Labor market conditions have improved further, with strong job gains and a lower unemployment rate... Inflation has declined further below the Committee's longer-run objective, largely reflecting declines in energy prices. Market-based measures of inflation compensation have declined substantially in recent months; survey-based measures of longer-term inflation expectations have remained stable.
>
> ... Inflation is anticipated to decline further in the near term, but the Committee expects inflation to rise gradually toward 2 percent over the medium term as the labor market improves further and the transitory effects of lower energy prices and other factors dissipate. The Committee continues to monitor inflation developments closely.
>
> To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will

[18] http://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20140917.pdf.

> assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. Consistent with its previous statement, the Committee judges that an increase in the target range for the federal funds rate remains unlikely at the April FOMC meeting. The Committee anticipates that it will be appropriate to raise the target range for the federal funds rate when it has seen further improvement in the labor market and is reasonably confident that inflation will move back to its 2 percent objective over the medium term. This change in the forward guidance does not indicate that the Committee has decided on the timing of the initial increase in the target range.
>
> The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.
>
> When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.[19]

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets indicate a lower cost-of-capital environment than that which existed in 2012. If one were to assume that the risk premium[20] required for investing in utility stocks rather than utility bonds was constant, then the current lower utility debt yields translate into a lower required return on equity than in 2012.

The average utility bond yields have generally declined since 2012. The 12 month averages for 2012, 2013 and 2014 were 4.80%, 4.70% and 4.47% respectively. And the 2015

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[19] http://www.federalreserve.gov/newsevents/press/monetary/20150318a.htm.

[20] Risk Premium in this context is the excess required return to invest in a company's equity rather than its debt.

average, based on January and February data, is 3.85%. Utility bond yields were at a historical low (3.80%) in January 2015, but did increase slightly (3.90%) in February 2015. The average utility bond yield for the first 6 months of 2012 (the general time frame in which capital market data was analyzed for the electric utility cases in which the Commission last made a determination on a fair and reasonable allowed ROE) was 4.94%. The average utility bond yield for the most recent 6 months (through February 2015) was 4.11%, a decline of 83 basis points. (*see* Schedules 4-1 and 4-3). For the most recent 6 months through February 2015, the average spread between 30-year T-bonds (2.87%) and average utility bond yields (4.11%) was 124 basis points. For the first 6 months in 2012, the average spread between 30-year T-bonds (3.04%) and the average utility bond yields (4.94%)[21] was 190 basis points. The decline in the spread is explained mainly by the decline in utility bond yields since 2012. (*see* Schedules 4-3 and 4-4).

b. Utility Equity Markets

For the twelve months ending February 28, 2014, the total return on the Dow Jones Industrial Average was 11.10%, the total return on the Standard & Poor's 500 ("S&P 500") was 13.18%, and the total return on the Edison Electric Institute (EEI) Index of electric utilities was 16.23%. Typically, over long holding periods utility indices tend to lag behind broader market indices that are increasing or decreasing. However, regulated utilities, with minimal non-regulated operations, are not expected to be as cyclical as the broader markets because of low demand elasticity. The equally weighted returns for the EEI's indices of electric utility companies since 2009 are as follows:

	2009	2010	2011	2012	2013	2014[22]
EEI Broad Index	14.1%	11.9%	21.4%	4.8%	17.3%	10.2%
Regulated	14.2%	15.8%	22.3%	4.7%	17.0%	9.6%
Mostly Regulated	15.6%	8.5%	19.5%	5.8%	16.0%	13.8%
Diversified	8.1%	-5.2%	21.4%	0.8%	47.5%	-0.9%

[21] For utility bond yields prior to September 2010, Staff used Mergent Bond Record. For utility bond yields subsequent to this period, Staff used data it receives from BondsOnline pursuant to a subscription agreement.

[22] For the first 9 months of 2014, because as of March, 2015, EEI had not updated the returns through December 31, 2014.

Chain linking[23] these returns provides the following total return performance for all of the categories provided by EEI: EEI Broad Index: 109.98%; EEI Regulated Index: 117.14%; EEI Mostly Regulated Index: 109.33%; and EEI Diversified Index: 83.31%.

Although the above returns are equally weighted returns and the S&P 500 is a market-weighted return, reviewing the performance of the S&P 500 over the same period is helpful in evaluating relative performance of utilities as they relate to the broader markets:

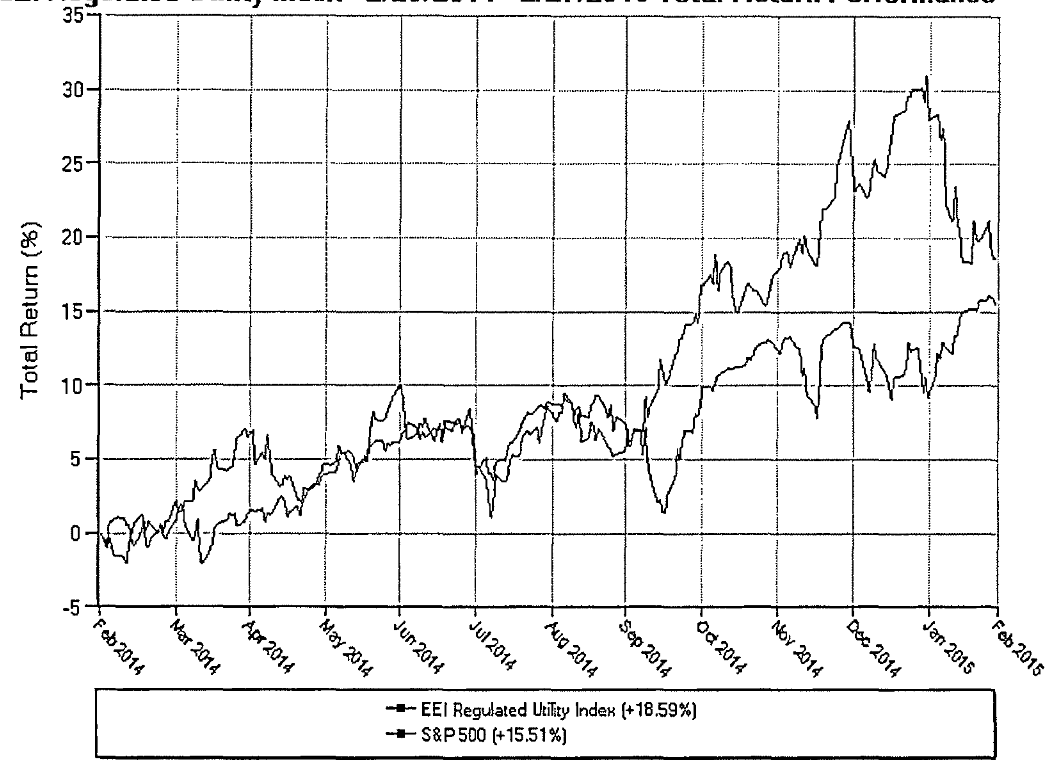
	2009	2010	2011	2012	2013	2014
S&P 500	26.5%	15.1%	2.1%	16.0%	32.4%	8.3%

Chain linking the S&P returns indicates total return performance of 147.27%, which is greater than the total return performance of all of EEI's indices. Traditionally, over long-term market periods, total returns on the S&P 500 should outperform regulated utilities by approximately 20% because betas on regulated utilities typically are around 0.7, implying that the risk premium required to invest in utilities should be approximately 70% of the risk premium required to invest in the S&P 500. For the period Staff analyzed above, the EEI regulated utility index lagged the S&P 500 by approximately 20%. This was slightly higher than the 10% it had lagged the S&P 500 just one quarter prior. Consequently, there was some correction to the long-term return spread between the S&P 500 and the EEI regulated utility index in the third quarter of 2014. However, the graph below depicts the significant outperformance of the EEI Regulated Utility Index compared to the S&P 500 (by a 2-to-1 margin) for the period October 2014 through January 2015. The graph below also illustrates the significant pullback of the EEI Regulated Utility Index in February 2015.

continued on next page

[23] A process for combining periodic returns to produce an overall time-weighted rate of return. 2009 CFA Program Curriculum, Level III, Volume 6, p. 120.

EEI Regulated Utility Index - 2/28/2014 - 2/27/2015 Total Return Performance



The significant outperformance of the utility sector through January 2015 can be largely explained by the unexpected drop in long-term interest rates through this period. The decline in long-term interest rates was perplexing to most because the Fed discontinued the bond buying program, which had the intended effect of reducing long-term interest rates. Because the decline in long-term interest rates occurred at the same time as a drop in oil prices, it appears there may be concern about low growth and low interest rates globally. Although treasury yields and utility bond yields increased in February 2015 and utility stock prices generally contracted as a result, the general level of interest rates remains low and continues to support a low cost of capital environment for utilities for both their equity capital and their debt capital.

In fact, many utility equity analysts during the past few years have consistently discussed the premium at which regulated utility stocks have traded as compared to the S&P 500, which is not typical over the long-term in capital markets. Typically, due to the low-growth and high-dividend yield characteristics of utility stocks, the price-to-earnings ratios are lower for utility stocks as compared to the higher-growth, lower-yield profile of the S&P 500. Equity analysts consistently explain that the higher multiples are driven by the low interest rate environment, not higher growth expectations for the regulated utility industry as compared to the broader markets.

Goldman Sachs' analysis consistently shows that utilities typically trade at a premium to the market when U.S. 10-year treasury yields trade below the 3% level and trade at a discount to the market when U.S. 10-year treasury yields trade above 3%. On January 14, 2015, the U.S. 10-year treasury yield reached a low of 1.789%, but has since increased to 1.92% as of March 25, 2015.[24] Goldman Sachs also points out that the projected compound annual growth rate ("CAGR") in Earnings Per Share (EPS) for utilities for the 2013 through 2016 averages approximately 5%, which is below most all other sectors in the S&P 500. Coupling the fact that utilities are trading at a premium to the S&P 500 even though utilities have lower growth expectations than the S&P 500, clearly indicates that utilities' cost of equity is quite low in the current economic and capital market environment. Assuming the Commission accepts these capital market experts' views on the reason for the current higher valuation levels of utilities, then the key question the Commission needs to answer in determining a fair allowed return on equity in this case is whether changes since the Commission heard evidence in 2012 when it authorized an ROE of 9.8% for Ameren Missouri and 9.7% for KCPL and GMO justify a decrease, increase or no change to KCPL's allowed ROE.

Although Staff will provide more specific information about its specific cost of equity analysis of its proxy groups later in its testimony, Staff will provide a brief overview of the changes in the capital markets since the Commission authorized a ROE for KCPL based on capital market evidence through approximately mid-2012.

At the time Staff filed its direct testimony in the Ameren Missouri, KCPL and GMO rate cases, the 6-month average utility bond yield through June 2012 was 4.94%. At the time Staff was preparing its testimony for this case, the 6-month average utility bond yield through February 2014 was 4.11%, a decline of 83 basis points. Although not as indicative of utility capital costs, the 6-month average U.S. 30-year Treasury yield was 3.04% for the first 6-months of 2012. At the time Staff was preparing its testimony for this case, the 6-month average U.S. 30-year U.S. Treasury yield was 2.87%, a decrease of 17 basis points.

[24] http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Although Staff believes the decline in utility bond yields provides the most tangible support for lowering the allowed ROE from the Commission's previous authorizations, it is important to evaluate the impact the lower bond yields have had on both the absolute and relative performance of electric utility indices and broader market indices over the period since the Commission last authorized ROEs for electric utilities in Missouri. As provided in the table above (but partially reproduced below for convenience), the total returns for each of the indices were as follows since January 1, 2012:

	2012	2013	2014
EEI Broad Index	4.8%	17.3%	10.2%
Regulated	4.7%	17.0%	9.6%
Mostly Regulated	5.8%	16.0%	13.8%
Diversified	0.8%	47.5%	-0.9%
S&P 500	16.0%	32.4%	8.3%

Chain linking these returns provides the following total return performance for all of the indices: EEI Broad Index: 35.47%; EEI Regulated Index: 34.26%; EEI Mostly Regulated Index: 39.66%; EEI Diversified Index: 47.34%; S&P 500: 66.33%. Although this information provides insight on the performance of the market, without analyzing the reasons for the performance differences, it will not provide much insight on any potential changes in the cost of equity since 2012.

Below is a graph of the change in the price-to-last-twelve-months'-earnings ratios ("p/e ratios") for EEI's current regulated utility index from the beginning of January 1, 2012, through February 28, 2015. As can be seen, the p/e ratios have increased since the Commission determined that an allowed ROE in "the 2012 rate cases" should be in the range of 9.70% to 9.80%. The increase in the p/e ratios for the electric utility industry indicates that the cost of equity has declined further since the Commission last decided allowed ROEs of 9.70% to 9.80% were fair and reasonable.

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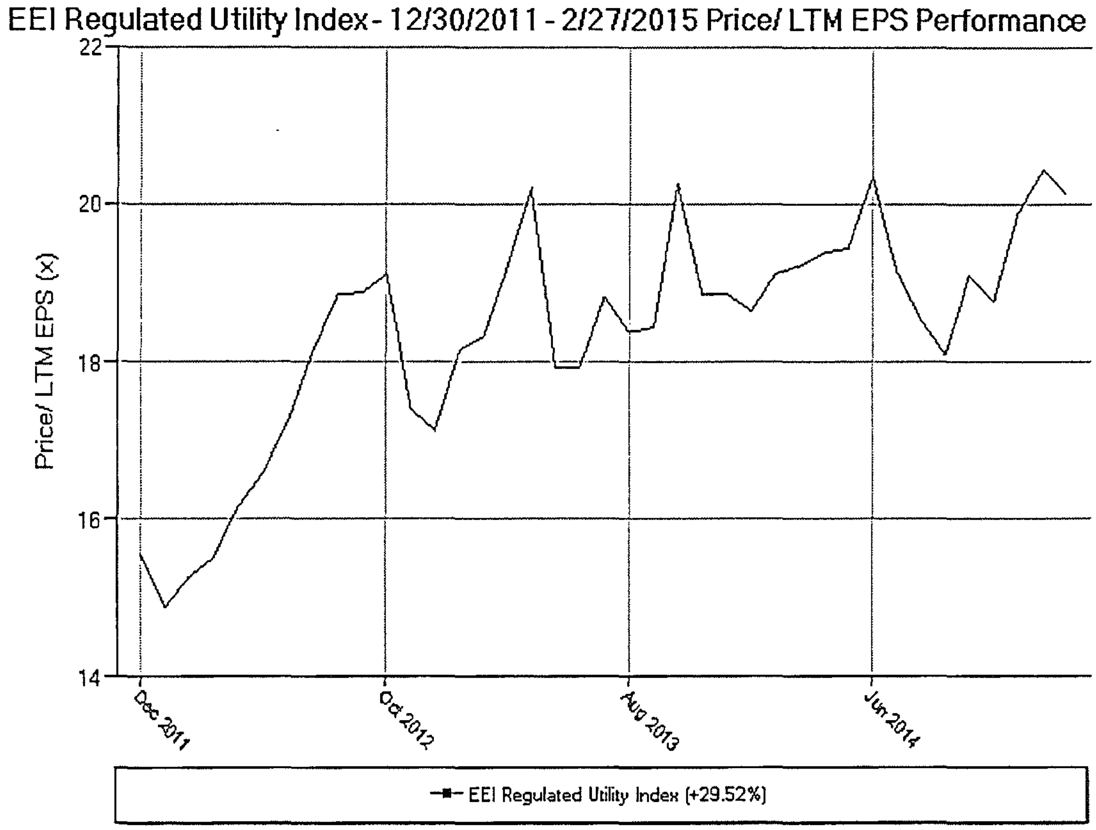

As explained by EEI itself, the continued general increase in electric utility stock prices is not explained by the fundamentals of the industry, but by the macroeconomic environment, which has caused investors to continue to lower their required ROE's, i.e., the cost of common equity. EEI specifically stated the following in its report on electric utility stocks through the second quarter of 2014:

> The EEI Index surged 18.0% in the first half of 2014, outperforming the major averages after markedly trailing in 2012 and 2013. As has typically been the case in recent years, performance was influenced more by macroeconomic trends (declining interest rates and firming natural gas spot prices in early 2014) than any significant change in industry fundamentals.[25]

While the last portion of the graph above exhibit some degree of contraction in the p/e ratios that resulted from the general drop in the market value of utilities, equity analysts still view utilities

[25] Edison Electric Institute Second Quarter 2014 Financial Update.

as trading at levels higher than the historical norm. Below is an excerpt from a recent UBS Global Research report (US Electric utilities & IPPs – Is it Safe to Buy Utilities Yet?) dated March 13, 2015:

> **The short answer: probably not although there are positive signs**
> With utilities underperforming the broad market -7.8% year-to-date and showing a particularly steep -14.4% since the end of January, it may be reasonable to ask whether we've seen the bottom of relative performance this year. Utilities continue to trade at an elevated 2-year forward P/E of 16.7x vs an average of 14.3x since 2005. However, things don't look as bad on a relative P/E (to the S&P 500) basis, with utilities now trading exactly in-line with the S&P after the recent drop, which also happens to be in line with the 101% average since 2005. Nevertheless, we would not get aggressive quite yet considering the more historical 25-year average of 82% of the S&P 500 P/E, which was last reached in 2009 during the turmoil of the financial crisis. Prudence would suggest waiting for at least another 5%-10% underperformance before calling a "bottom".

Although such commentary does not estimate how much the cost of equity has declined, it definitely provides evidence that it has declined since 2012.

Staff also decided to analyze the changes in the price-to-forward EPS multiples, as reported by FactSet[26], because these multiples are often discussed by equity analysts and investors when evaluating whether a stock is attractively valued (lower P/E ratio than implied in its valuation). In 2012 the average P/E ratio for EEI's regulated electric utilities was 16.3x; in 2013 it increased to 16.9x and in 2014 it increased to 18.5x. The p/e ratio based on a forward earnings estimate for 2015 was 17.3x at the time Staff prepared this testimony.

Although Staff is introducing different criteria to select its proxy group in this rate case as compared to the criteria it used in the 2012 rate cases, Staff performed an updated analysis of the proxy group it used in 2012 for purposes of evaluating and quantifying any potential changes to the cost of equity for the proxy group. Being that the main issue the Commission had with Staff's cost of equity estimate in the last rate case was that it was too low, which was primarily driven by Staff's use of a lower perpetual growth rate, the Commission should focus on the relative change in Staff's cost of equity estimate compared to 2012 rather than the absolute estimate. Because perpetual growth rates should not change much over time, Staff believes that simply updating the rest of the data and still using the same perpetual growth rate will provide a good estimate of the relative change in the cost of equity.

[26] Staff receives FactSet compilation of equity analyst estimates through its subscription to SNL Financial.

Staff's proxy group in KCPL's 2012 rate case contained ten companies. If Staff were simply updating the cost of common equity analysis of this proxy group, Staff would need to eliminate Cleco Corporation and Wisconsin Energy because these two companies are currently involved in mergers and acquisitions. At the time of KCPL's 2012 rate case, the average forward p/e ratio for the proxy group, absent Cleco and Wisconsin Energy, was approximately 14.12x based on 2011 year-end prices applied to projected 2012 EPS. The current average forward p/e ratio for the same proxy group is approximately 17.15x based on a 3-month average of January 2015, February 2015 and March 2015 stock prices applied to projected 2015 EPS. With reference to a more specific time horizon, the forward p/e ratios have increased since the Commission heard the facts and opinions presented in the Ameren Missouri's most recent rate case. The monthly forward p/e ratios from October 2014 to March 2015 were 16.55x, 16.65x, 17.68x, 18.28x, 16.76x and 16.80x respectively. Because the projected average 5-year EPS growth rates of these eight companies have actually declined by approximately 60 basis points from approximately 5.40% to 4.80%, the only explanation for the expansion of the p/e ratios for these companies since the last rate case is an additional decline in the required ROE, i.e. the cost of equity, for the regulated electric utility industry due to the realization that our economy continues to be in a low-yield, low-growth state.

While the recent contraction in utility stock prices since February 2015 shows a lower forward P/E ratio for 2015 as compared to 2014, the p/e ratios are still above the levels in 2012, which supports the Commission lowering the allowed ROE from the levels it authorized in 2012. The current price levels of Staff's proxy group are consistent with the prices Staff used in the Ameren Missouri rate case, which supported Staff's position to lower the allowed ROE by 25 to 75 basis points. The stock prices from November 2014 through January 2015 supported the consideration of an even larger reduction to the allowed ROE as reflected in Staff's DCF analyses in this testimony when using these higher stock prices. Although there has been some fluctuation in the valuation levels of utility stocks in recent months, the general level of interest rates is still low as compared to 2012 and support lower allowed ROEs. Below is an excerpt from Moody's investor service that provides justification and the financial effects of lowering allowed ROEs:

> US Regulated Utilities
>
> Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinise their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. Regulators can also adjust a utility's equity capitalization in its rate base. All else being equal, we think most utilities would prefer a thicker equity base and a lower authorized ROE over a small equity layer and a high authorized ROE.

D. Great Plains', KCPL's and GMO's Operations

The following excerpts from a combined, Great Plains and KCPL, Form 10-K filing with the United States Securities and Exchange Commission ("SEC") for the 2014 calendar year, provides a good description of Great Plains' current business operations and current organizational structure:

> Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's wholly owned direct subsidiaries with operations or active subsidiaries are as follows:
>
> • KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
>
> • GMO is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.
>
> Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource

under the equity method. Transource is focused on the development of competitive electric transmission projects.

Great Plains Energy's sole reportable business segment is electric utility. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 23 to the consolidated financial statements. Comparative financial information and discussion regarding the electric utility business segment can be found in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

The electric utility segment consists of KCP&L, a regulated utility, GMO's regulated utility operations which include its Missouri Public Service and St. Joseph Light & Power divisions and GMO Receivables Company. Electric utility serves approximately 838,400 customers located in western Missouri and eastern Kansas. Customers include approximately 737,400 residences, 98,400 commercial firms and 2,600 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 91% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 100%, 103% and 108% of Great Plains Energy's net income in 2014, 2013 and 2012, respectively.

E. KCPL, Great Plains and GMO Credit Ratings

Credit Ratings

KCPL, Great Plains and GMO are currently rated by Moody's and Standard & Poor's ("S&P"). The senior unsecured credit ratings from the two rating agencies are generally consistent even though Moody's currently rates GMO one notch lower than S&P. The table below shows the current credit ratings for KCPL, Great Plains and GMO:

continued on next page

GPE, KCP&L & GMO CREDIT RATINGS					
Senior Unsecured Credit Rating				S&P Business and Financial Risk	
	Moody's		S&P	BRP	FRP
GPE	Baa2	*	BBB+ **	Excellet	Significant
KCP&L	Baa1	*	BBB+ **	Excellent	Significant
GMO	Baa2	*	BBB+ **	Strong	Significant

Notes: * Upgrade as of 1/31/2014
: ** Upgrade as of 5/1/2014
:Moody's Baa1, Baa2 & Baa3 is an equivalent of S&P BBB+, BBB & BBB-
:BRP - Business Risk Profile & FRP - Financial Risk Profile
Source: SNL Financial (credit ratings) and May 2, 2014 RatingsDirect Reports (BRP and FRP)

The S&P corporate/ issuer credit ratings for all the three entities is "BBB+"; and the standalone credit ratings for KCPL and GMO are "A-" and "BBB," respectively. KCPL's standalone credit rating is one notch stronger, *and GMO is one notch weaker*, than Great Plains' group corporate rating ("BBB+"). The standalone credit ratings are based on each entity's business and financial risk profiles. As furnished in the table, GMO's business risk profile in one notch weaker than KCPL and Great Plains'.

While Staff is estimating cost of equity for KCPL, it is important to understand the current credit profiles of KCPL, Great Plains and GMO, as their ratings collectively influence the investors' views of the risks associated with investing in KCPL.

Moreover, Staff established in the Cost of Service Report in the 2012 KCPL rate case, Case No. ER-2012-0174, pages 34-37, the interdependence among these three entities despite their standalone credit ratings. When Great Plains acquired Aquila, Inc. (now GMO), Aquila had a "junk" credit rating status – which was subsequently raised to investment grade status since Great Plains provided a guarantee of Aquila's debt after it completed the acquisition of Aquila's Missouri utility properties. Great Plains' credit profile at the time was principally supported by KCPL's regulated assets and operations.

The following is an excerpt from Great Plains' February 25, 2015's Form 10-k filing that furnishes the credit rating and financial support interdependence among the three entities:

> Great Plains Energy, KCP&L, GMO and certain of their securities are rated by Moody's Investors Service and Standard & Poor's. These ratings impact the Companies' cost of funds and Great Plains Energy's ability to provide credit support for its subsidiaries. The interest rates on borrowings under the Companies' revolving credit agreements and on a portion of

> Great Plains Energy's debt are subject to increase as their respective credit ratings decrease.

The following is an excerpt from S&P's May 1, 2014, credit-rating report on Great Plains, discussing the influence of KCPL and GMO's business risk:

> We view GPE's business risk as "excellent" incorporating our assessment of the regulated utility industry risk as "very low" and country risk as "very low" based on the company's focus on U.S. operations and markets. The business risk profile reflects a competitive position of "strong". KCP&L serves electricity to customers in and around Kansas City and its suburbs. GMO serves electricity to about 300,000 customers in western Missouri. Together the two utilities have about 800,000 customers. The company operates with generally supportive regulation, a primarily residential customer base that supports cash flow stability, good operating efficiency and absence of competition. GPE continues to focus on a regulated business strategy. The ongoing capital spending will require timely recovery of these costs through various rate mechanisms including base rates and rate surcharges that should strengthen cash flow. For the La Cygne emissions control construction, the company does not have rider recovery and will need to seek base rate changes to recover new construction costs. KCP&L expects the Kansas commission to issue a decision by mid-2014 in its pending $12 million abbreviated rate case to begin recovering costs related to the installation of La Cygne's environmental compliance equipment. This should ultimately boost operating cash flow. Riders also exist for the recovery of fuel costs and transmission charges.

S&P's methodology of assessing corporations in general, and utilities in specific, has changed since 2012. KCPL is now assigned a "regulatory/advantage" score based on S&P's assessment of the regulatory environment and the utility company's ability to manage the regulatory environment. S&P considers the Missouri regulatory environment for electric utilities to be "Strong/Adequate" which is one notch below the best category of "Strong."

S&P's methodology compiles a list of regulatory jurisdictions for investor-owned utilities in the U.S; and the each jurisdiction is placed, *in ranking order*, into one of the five classes ("strong," "strong/adequate," "adequate," "adequate/weak" and "weak") *–which simply represent the score assigned to each jurisdiction.* According to S&P's ranking order, Missouri is in the last 25th percentile range of both (1) the entire jurisdiction listing and (2) a listing of jurisdictions that have same score ("Strong/Adequate") as Missouri. However, since there is no known quantification, nor specific details for the differences in the ranking order, Staff can only default to S&P's conclusion that the Missouri regulatory environment is generally credit supportive.

F. Cost of Capital

In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an appropriate ratemaking capital structure, (2) KCPL's embedded cost of debt, and (3) the change in KCPL's cost of common equity.

1. Capital Structure

Staff recommends the use of Great Plains' consolidated capital structure as it is consistent with the capital structure ordered in the last KCPL's rate case (Case No. ER-2012-0174).[27] Schedule 7 presents Great Plains' consolidated capital structure and associated capital ratios as of the update period (December 31, 2014) –50.31% equity, 0.55% preferred stock and 49.14% long-term debt.[28]

2. Embedded Cost of Debt

Staff recommends the use of Great Plains' consolidated embedded cost of debt as it is consistent with the embedded cost of debt ordered in the last KCPL rate case (Case No. ER-2012-0174).[29] Schedule 6 presents Great Plains' consolidated debt ratio (49.19%) and a computation of the consolidated embedded cost debt (5.55%) as of the update period – December 31, 2014.[30]

3. Cost of Common Equity

Staff estimated KCPL's cost of common equity through a comparable company cost-of-equity analysis of a broader proxy group and a more refined proxy group using the DCF method. Staff also compared the new proxy groups and the proxy group in KCPL's last rate case to estimate the relative change in the cost of equity since 2012. Additionally, Staff used a CAPM

[27] ER-2012-0174, Report and Order, Issue and Effective Date: January 9, 2013 - page 24.

[28] KCPL's response to Staff's Data Request No. 120.

[29] ER-2012-0174, Report and Order, Issue and Effective Date: January 9, 2013 - page 26.

[30] KCPL's response to Staff's Data Request No. 120.

analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Groups

Staff decided to perform a cost of common equity analysis on two sets of proxy groups in this case. Although Staff has revised its selection criteria to select a current proxy group, considering the insight that can be gained about the relative change in the cost of common equity by evaluating the proxy group Staff used in the rate cases in 2012, Staff decided to update the cost of common equity analysis on this proxy group as well. Staff limited its DCF analysis of the old proxy group to the multi-stage DCF since Staff gave this the most weight in the last case and because it is dynamic enough to consider near-term growth rate impacts. The only changes Staff made to the proxy group from 2012 was to eliminate Cleco Corporation and Wisconsin Energy Resources because their stock prices are currently influenced by announced mergers and acquisitions. Staff will first explain how it selected the new proxy group and provide cost of common equity indications from this proxy group. Staff will then update the cost of common equity analysis from the proxy group in 2012 and compare the new results to the old results to draw inferences about the change in the cost of equity since 2012.

Although Staff has changed its proxy group selection process as compared to the 2012 rate cases, the ultimate goal is the same, which is to select companies whose operations are confined as much as possible to regulated utility operations ("pure-play regulated utilities"/ "pure-play") with a majority of the regulated utility operations being that of the electric utility sector. Staff believes its ability to access a vast amount of financial and capital market information through its upgraded subscriptions to SNL Financial now allows for a much more efficient and detailed analysis of companies that are generally classified as electric utilities, but may have significant amounts of other operations that contribute to their risk profile. In the past, Staff relied on various third-parties, such as credit rating agencies and certain publishers, to assist with attempting to select appropriate companies. Although this usually resulted in a reasonable proxy group, Staff's easy and efficient access to very detailed financial information has allowed it to refine its proxy group selection process and become more aware of companies which have material non-regulated business segments that cause their risk profiles to be inconsistent with a pure-play regulated utility. Staff's explanation of its new process follows:

Starting with 64 market-traded companies classified as power companies by SNL Financial, Staff applied a number of criteria to develop a proxy group comparable in risk to KCPL's regulated electric utility operations (*see* Schedule 8). Staff's criteria are designed to capture companies with primarily regulated electric operations (which means the companies' operations may have other regulated operations, such as gas distribution), and whose electric utility operations contain a significant amount of generation assets. Staff believes the criteria it selected accomplished this objective. However, Staff notes that even with its screening criteria, some of the companies it chose for its proxy group have business segments other than rate-regulated utility operations that cause material volatility in the contribution of the regulated utility operations to the percentage of income on a year-to-year basis. That being said, Staff will refine its broader proxy group to eliminate two additional companies that have material volatility in the percentage of income from regulated operations due to the volatility of income from its non-regulated segments. However, Staff will show the results of the broader proxy group and the refined proxy group in each of its schedules. It should also be noted that the financial data Staff used to select its proxy group was the same as Staff used for the Ameren Missouri and Empire rate cases. Although 2014 financial data has been released, Staff believes it can provide the Commission with more reliable information about the changes in the capital markets over the last few months if Staff holds its proxy group constant in this case and compare the data to the other rate cases. Staff's criteria are as follows:

1. Classified as a power company by SNL (64 companies);
2. Publicly-traded stock (one company eliminated, 63 remaining);
3. Followed by EEI and classified by EEI as a regulated utility (29 companies eliminated, 34 remaining);
4. At least 50% of plant from electric utility operations (4 companies eliminated, 30 remaining);
5. At least 25% of electric plant from generation (8 companies eliminated, 22 remaining);
6. At least 80% of income from regulated utility operations (2 companies eliminated, 20 remaining);
7. No reduced dividend since 2011 (0 companies eliminated, 20 remaining); and

8. At least investment grade credit rating (0 companies eliminated, 20 remaining);

9. At least 2 equity analysts providing long-term growth projections in the last 90 days (6 companies eliminated, 14 remaining); and

10. No significant merger or acquisition announced recently (0 companies eliminated, 14 remaining).

The resulting final group of 14 publicly-traded electric utility companies ("the comparables") was used as the broader proxy group to estimate a cost of common equity for the electric utility industry. These companies are shown on Schedule 8.

The final criterion used to eliminate any remaining companies that may have segments that have risks inconsistent with a regulated utility is criterion No. 6. In order to select companies that consistently received at least 80% of their income from rate-regulated utility operations, one has to review past performance (Staff chose the last 3 years). However, limiting the selection criteria to just looking at the average amount of income from regulated utility operations can cause the selection of companies that have material volatility in the percentage of income contributed by the regulated utility operations simply because a non-regulated segment may contribute 25% to margin in one year and then reduce margin by 10% in the following year. In the latter situation, one would erroneously conclude that the risk profile of the company is consistent with a regulated utility since the regulated income was over 100% of the company's income. If one were to take a simple average of these two years, then the company would be selected as a comparable company based simply on the fact that 92.5% of the average income came from regulated utility operations. Being that the non-regulated operations significantly increased the variability of income, it is important to add an additional criterion to eliminate companies that have such volatile segments.

Consequently, Staff decided to further refine its broader proxy group to eliminate companies in which the contributions of income from rate-regulated utility operations had a standard deviation of greater than 10% for the most recent three years. If the contribution from regulated utility operations is varying significantly from year to year, then this will make the cost of capital inconsistent with the risks of the regulated utility operations. Staff used standard deviation because it measures the degree of dispersion from the mean. Staff chose 10% because this is the threshold for determining if a segment is material and must be reported according to

Generally Accepted Accounting Principles (GAAP) that govern the requirements regarding segment reporting. Segment reporting requirements had been governed by Statement of Financial Accounting Standard 131, which has now been reclassified as Accounting Standard Codification No. 280. Materiality of a business segment, as defined by GAAP, is defined as follows:

> a. Its [operating segment] reported revenue, including both sales to external customers and intersegment sales or transfers, is 10 percent or more of the combined revenue, internal and external, of all operating segments.
>
> b. The absolute amount of its reported profit or loss is 10 percent or more of the greater, in absolute amount, of either:
>
> 1. The combined reported profit of all operating segments that did not report a loss
> 2. The combined reported loss of all operating segments that did report a loss.
>
> c. Its assets are 10 percent or more of the combined assets of all operating segments.

For purposes of evaluating whether a company's non-regulated segments were causing a material variability in income as to make its business risk inconsistent with the regulated business risk profile of a regulated electric utility, Staff decided to use the 10% threshold to define material volatility. Consequently, keeping with GAAP's definition of material being at least 10% of profit or loss, Staff excluded companies whose regulated utilities contribution to income had a standard deviation greater than 10%. However, if a company had swings in its regulated income contribution of 10% or more, but it has since divested the segment that caused these swings, such as Ameren, then Staff included these companies. The two companies that had a greater than 10% standard deviation in the percentage of income from regulated utility operations were OGE Energy and TECO Energy. Staff will provide cost of common equity information for the broader proxy group and for the refined group, which excludes OGE and TECO.

b. The Constant-growth DCF

Next, Staff estimated KCPL's cost of common equity by applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[31] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D1/P0, the expected next 12-months' dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the pro-rated 2015 and 2016 fiscal year FactSet projected dividends per share (*see* Schedule 12) by the monthly high/low average stock price for the three months ending February 28, 2015 (*see* Schedule 11).[32] Staff used the above-described stock price because it reflects current market expectations. The projected average dividend yield for the broader proxy group of fourteen comparable companies is approximately 3.51 %, unadjusted for quarterly compounding. The projected average dividend yield for the refined proxy group of twelve comparable companies is also approximately 3.48%, unadjusted for quarterly compounding.

i. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered the actual dividends per share ("DPS"), EPS and book value per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be quite

[31] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset*, University Edition, John Wiley & Sons, Inc., 1996, p. 195-196; John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 64.

[32] The monthly high/low averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P0 is calculated by averaging the highest and the lowest price for each month during the selected period.

volatile, at least for a few of the companies in the proxy group.[33] Staff also reviewed equity analysts' consensus estimates for long-term compound annual growth rates as reported by FactSet and provided by SNL Financial. The average consensus long-term growth rates for the broader proxy group is currently 5.74 % as compared to 5.57 % for the refined proxy group. (*see* Schedule 10-6).

While Staff may accept the argument that electric utilities EPS can grow at a near-term growth rate of approximately 5.70%, *a rate which is obviously higher than the consensus GDP long-term growth rate estimates*, Staff notes that it would be unreasonable to conclude that this growth rate is sustainable in perpetuity because it does not give consideration to empirical and logical information that suggests that utility companies should grow at a rate less than that of the overall economy.

Historical data also indicates that companies in the S&P 500 (a proxy for the U.S. capital markets) in recent years have retained approximately 65% to 70% of their earnings for reinvestment, [34]*which indicates that the on average, the companies expect to be able to achieve more than half of their returns from capital gains driven by investment opportunities.* In that instance it is intuitive to estimate the cost of equity using a multi-stage DCF that reflects a higher-than-GDP growth rate in the first stage(s) and then a consensus long-term GDP growth rate estimate for the perpetual stage.

For electric utilities, however, the average retention ratio has been less than half that of the S&P 500, [35]*which indicates that the fundamentals of electric utilities do not support a significant amount of organic growth in rate base and earnings from related operations.* Consequently, it makes logical sense to assume that utilities will grow at a rate less than that of nominal GDP growth in perpetuity. A projected long-term nominal GDP growth rate[36] should be conservatively ascribed as an upper constraint when testing the reasonableness of growth rates used to estimate the cost of equity for a regulated electric utility. Staff will provide more detail on economic growth projections when discussing the multi-stage DCF, but a high-end estimate

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[33] Schedule 10-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 10-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

[34] Table B-95 and B-96 attached to the *2013 Economic Report of the President.*

[35] http://www.wyattresearch.com/article/dividend-payout-ratio.

[36] The nominal GDP growth rate, contrasted to the real GDP growth rate introduced earlier, is not adjusted for inflation.

for nominal GDP is not much higher than 4.5%, causing an estimated constant growth rate over this rate to be highly suspect.

Because Staff is not relying on the constant-growth DCF to quantify the change in the cost of equity since the 2012 rate cases, Staff's growth rate estimate for the constant growth DCF is based on some common sense restraints on sustainable growth rates and the actual growth experience of the electric utility companies that have experienced more stable growth patterns. Several companies in Staff's proxy group have projected 5-year CAGR in EPS that simply are not sustainable in the long-term. Simply removing growth rates that exceed 6% reduces the projected 5-year CAGR in EPS to 4.86%. Considering that actual long-term growth experience in the electric utility industry barely supports a constant growth rate much more than 3%, Staff will use 3.5% as the low end and 4.5% for the high end investors' expectations of a constant growth rate. Consequently, for purposes of Staff's constant growth DCF for both the broader and more refined proxy group, Staff uses a growth rate range of 3.5% to 4.5%.

Using the growth rate range Staff established for the constant-growth DCF results in a cost of equity estimate of 7% to 8%. However, Staff again relied on its multi-stage DCF analysis to provide what it believes to be a more reliable cost of common equity due to the non-sustainable growth rates of a few companies in its proxy group.

c. The Multi-stage DCF

i. Overview

The constant-growth DCF model may not yield reliable results if industry and/or economic circumstances cause expected near-term growth rates to be inconsistent with sustainable perpetual growth rates.[37] Consequently, as in the last rate case, Staff again performed a multi-stage DCF analysis in this case and is relying primarily on this analysis to draw conclusions on the change in the cost of common equity since the last rate case because the multi-stage DCF is dynamic enough to consider changes in near-term growth rates, but still maintain a consistent perpetual growth rate as this rate should not change much, if any, because there have been no structural changes in the economy or industry to support it.

[37] Dr. Aswath Damodaran, Professor of Finance of the New York University Stern School of Business, advocates using a multi-stage methodology if the constant-growth rate is expected to be 1-2% different than the earlier stage growth rates. Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset*, University Edition, John Wiley & Sons, Inc., 1996, p. 193.

A multi-stage DCF may use either two or more growth stages, depending on the situation being modeled. In any case, the last stage must use a sustainable rate as it is considered to last into perpetuity. In fact, in Staff's experience, most DCF analyses do not assume a growth rate much higher than the expected rate of inflation, currently 2.0% to 2.5%. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate for the final stage because this rate is assumed to last into perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high growth first stage and the constant growth final stage.[38]

In the present case, Staff used a three-stage DCF approach, the stages being years 1-5, years 6-10, and years 11 to infinity.[39] For stage one, Staff gave full weight to the analysts' five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model, because Staff understands that these projections are designed to represent expectations over this same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate range of 3.00% to 4.00%; mid-point 3.50% (*see* Schedules 14-1 through 14-3). Based on this set of assumptions, Staff's estimated cost of equity for both the broad and refined proxy group ranges from approximately 7.08% to 7.97%, mid-point of 7.53%.

ii. Stage one

The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next several years. However, in the context of discounting expected future DPS, it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for

[38] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 71-72.

[39] In practice, Staff extended the third stage only to year 200.

purposes of estimating the growth in DPS in a single-stage, constant-growth DCF or for the final stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own analyses should be proof in and of itself that stock prices do not reflect this assumption. Consequently, Staff limited its use of these growth rates to the first five years of its analysis, the very period these growth rates are intended to cover.

iii. Stage two

Stage two, i.e. the transition stage, is simply a gradual movement from above normal growth to more normal/sustainable growth for the final stage. Although stage two can also consist of forecasted discrete cash flows, because it is a transitional period, it is logical to linearly reduce the high growth first-stage growth over a specific period in order to gradually reduce the growth rate to the expected sustainable growth rate. Staff chose to do this over a 5-year period, which is fairly conventional in multi-stage DCF analysis.

iv. Stage three

Stage three is the final/constant-growth stage. In fact, the final stage can be reduced to the single-stage, constant-growth form of the DCF. Although this is the "generic" stage, it is extremely important to select a reasonable growth rate for this stage to arrive at a reliable cost of equity estimate.

Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to the assumed perpetual growth rate. Staff performed an extensive amount of research on the actual realized growth rates of electric utilities over a 30-year period to estimate a 3.00% to 4.00% growth rate as a reasonable proxy for perpetual growth for the electric utility industry.

The Financial Analysis Unit has access to Value Line data on *Central* region electric utility companies dating back to 1968.[40] Staff believes it is important to analyze electric utility industry financial data to at least the early 1970s since this was approximately the beginning of the last large construction cycle for the electric utility industry.[41] Because 1968 is consistent

[40] Value Line has consistently published information the electric utility industry based on three regions: East, West and Central. The Central Region electric utility industry data is published in Edition 5 of The Value Line Investment Survey data. Staff maintained consistent and comprehensive files for the Central Region for reports published back to 1985, which provides electric utility per share data dating back to 1968.

[41] Daniel Ford, Gregg Orrill, Theodore W. Brooks, Ross A. Fowler, M. Beth Straka and Noah Howser, "Utilities Capital Management," July 16, 2009, Barclays Capital, p. 13 (Attachment D).

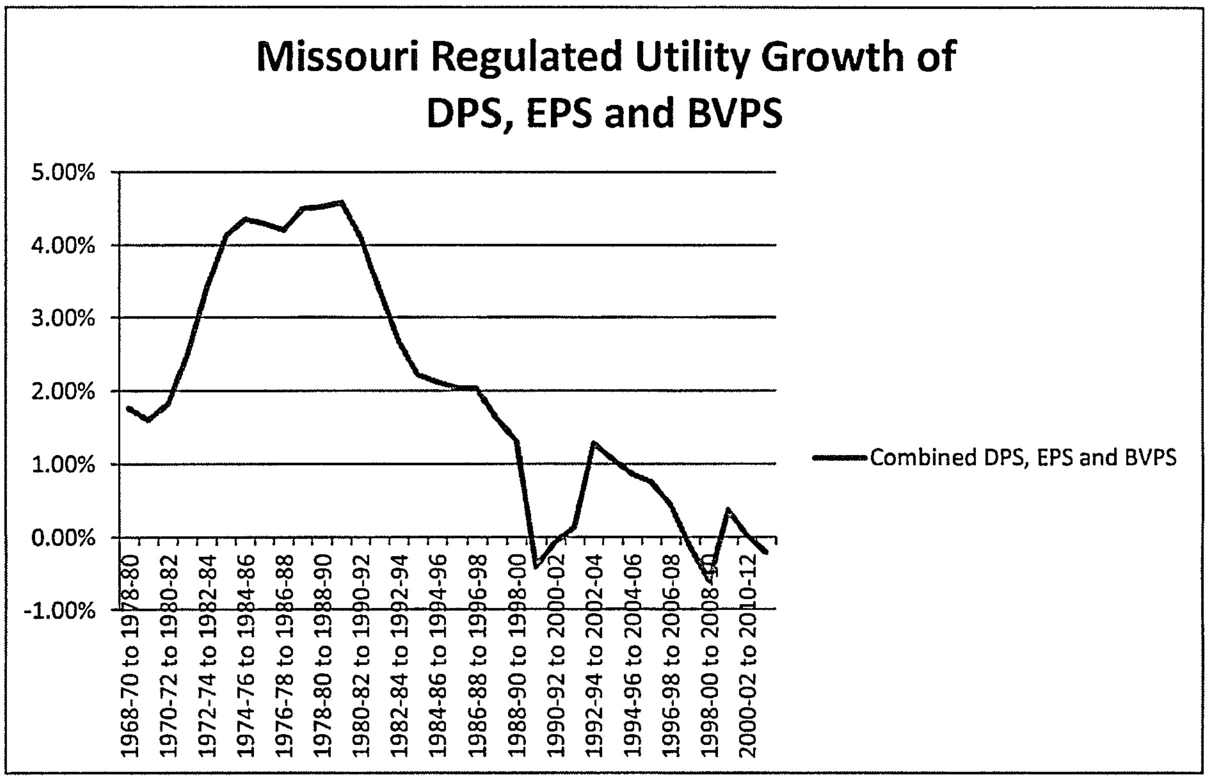
with the starting point of the last construction cycle, Staff decided to capture data starting in that year. Ideally, Staff would have analyzed data through the beginning of the current construction cycle, which started approximately during the middle of the past decade, but because many electric utility companies diversified into non-regulated merchant and trading operations towards the end of the 1990s and there was much consolidation during this same period, this noise causes any study relying on this more recent data to be less reliable in evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the electric industry occurred subsequent to the Enron, Inc., bankruptcy in December 2001. Considering that much of this disruption was caused by deregulation, Staff does not consider the information during this period to be informative for understanding investors' growth expectations for regulated electric utility operations.

Staff did not apply rigid selection criteria for purposes of selecting central region electric utility companies contained in Edition 5 of the Value Line Investment Survey. However, Staff did eliminate companies that generally did not have at least 70% of revenues from electric utility operations in the late 1990s. Staff also eliminated companies that appeared to be impacted significantly by events related to the restructuring of the electric utility markets in the mid to late 1990s. Staff also eliminated companies that had data comparability problems due to major mergers, acquisitions and/or restructurings. Staff only included companies in which comparable data was available for each year of the period 1968 through 1999. The companies Staff selected are shown in Schedules 14-1 through 14-4.

Staff's analysis of these electric utility companies' data over the last electric utility construction cycle indicates that average long-term growth slowly increased through the late 1980s and early 1990s and declined for the rest of the 1990s. The growth rates are based on Staff's calculation of a simple average of all of the companies' growth rates over this period. Because a simple average gives each company equal weight, Staff believes this approach is appropriate because it does not introduce size bias. As can be seen in the attached Schedules, the rolling average 10-year compound EPS growth rate for this period was 3.62%; the rolling 10-year compound DPS growth rate was 3.99%; the rolling 10-year compound BVPS growth rate was 3.18%; and the overall average for DPS, EPS and BVPS was 3.59%.

However, it is important to understand that these growth rates were achieved during a much more robust economic environment than the U.S. is expected to achieve in the foreseeable future. Also, considering that some rate of return witnesses' DCF analyses assume utilities can grow at the same rate as GDP in perpetuity, it is interesting to note that the average growth rate for these electric utilities was less than 50% of GDP growth over the same period.

Although Staff relied on the aforementioned proxy group for purposes of estimating a going forward sustainable industry growth rate, another relevant proxy group to evaluate growth trends for electric utility companies is the growth of the utility companies that actually have a large amount of their electric utility operations in Missouri. In addition to evaluating the growth of Missouri electric utility companies for the period 1968-1999, Staff also evaluated the growth of Missouri electric utility companies through 2014. As can be seen in the chart below, if the growth rates of the Missouri utilities are evaluated for the period after the 20th century, it is quite apparent that including this period would reduce the actual realized growth rate:



The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2014 were 1.67%, 1.58% and 2.38%, respectively, with an overall average growth rate of 1.88%. The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 1999 were 3.59%, 3.11% and 2.57%, respectively, with an overall average growth rate of 3.09%.

Consequently, including more recent financial data in evaluating the growth rate trends of Missouri's electric utilities actually supports the use of a perpetual growth rate that is less than the 3% to 4% that Staff chose to use in its multi-stage DCF analysis.

Of Missouri's utilities, The Empire District Electric Company's business operations have been the most consistent in being limited to regulated utility operations through the period analyzed. Although Great Plains has owned some non-regulated operations during the period Staff analyzed (e.g., Strategic Energy), these operations did not disrupt the financial performance of Great Plains to a great extent, even though they did increase Great Plains' risk profile. However, Ameren has incurred significant financial problems due to its ownership of merchant generation operations in Illinois. This exposure caused Ameren to incur significant losses in recent years, which would skew any financial growth rates that include this information. Although Empire and Great Plains did not incur financial difficulties due to non-regulated operations, both companies did reduce their dividends in recent years. Because of these issues that occurred around or after the recession and financial crisis in 2008 and 2009, Staff also determined the average growth of Missouri's utilities through 2007. The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2007 were 2.85%, 2.03% and 2.27%, respectively, with an overall average growth rate of 2.39%.

Obviously, the actual experienced growth rates of Missouri's electric utilities support the reasonable, if not lofty, perpetual growth rates Staff chose to use for its perpetual growth rate analysis. The actual realized growth rates of Missouri's utilities support a perpetual growth rate range of 2% to 3% rather than the 3% to 4% Staff decided to use. Although these growth rates are generally characterized as "low" when discussed in the utility ratemaking arena, these growth rates are more typical of those that are used by investors when determining a reasonable price to pay for a utility stock.[42] Additionally, considering that the dividend yield from utility stocks has historically produced 2/3 of the total return on utility stocks, [43] and the fact that dividend yields for electric utilities are currently approximately 4%, a 2% capital appreciation rate in utility

[42] Staff has analyzed many utility stock research reports over the last several years and has consistently observed much lower perpetual growth rates than those typically assumed in models for estimating the cost of equity for utility ratemaking.

[43] Hugh Wynne, Francois D. Broquin, Saurabh Singh, "U.S. Utilities: Our Dividend Growth Model Identifies Utilities Poised to Pay More," May 20, 2011, Bernstein Research.

stocks is about what investors would expect. This translates into an approximate expected return of 6% for utility stocks, which is quite logical and rational in the current low-yield environment.

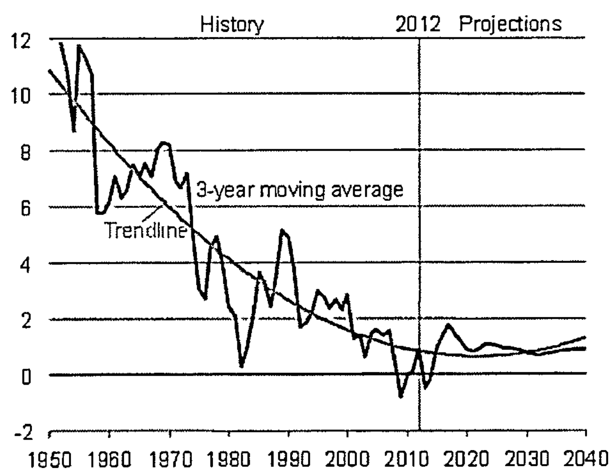
v. Constraints on Long-term Growth Rates used in Stage Three

In order to evaluate the credibility of an estimated perpetual growth rate for the electric utility industry, it is important to be aware of the changing fundamentals that have occurred and continue to occur within the electric utility industry due to changes in demand for electricity. In the past, growth in electric utility earnings and dividends was primarily driven by the increase in demand for electricity and the growth of customers using electricity. However, this dynamic has changed and the demand for electricity is no longer a primary growth driver for electric utilities. The decline in electricity demand growth is illustrated in the graph below:[44]

Electricity demand

Growth in electricity use slows, but use still increases by 29% from 2012 to 2040

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040 (percent)



The fact that the growth in electricity demand has been in a steady state of decline seems to explain the steady decline in electric utilities' financial performance over the period Staff analyzed in its previous discussion in this testimony. To the extent that potential financial growth for electric utilities is now limited to the ability to make additional investments and pass

[44] Energy Information Administration's *2014 Annual Energy Outlook*, p. MT-16.

the cost of these investments (which includes the allowed ROR) onto a near-constant customer base, any growth higher than needed capital investment to replace existing infrastructure would seem to be highly speculative and not sustainable. However, Staff notes that much of the rate base growth for electric utilities in recent years has been due to electric utilities making investments in their coal-based generating facilities in order to comply with various emission standards. These types of investments are policy-driven, and therefore are not controllable by management (although the amount of reasonable project costs are). Absent policy-driven investment requirements, it would seem that growth in investment would be limited to a rate similar to inflation because the only way to recover these costs is to raise rates on the existing customer base that is not using as much electricity.

vi. Update of Multi-Stage DCF Analysis on the Proxy Group from the 2012 Rate Cases

Staff updated the multi-stage DCF analysis it performed on the proxy group from KCPL's 2012 rate case to gain insight on first, the direction of the change of the cost of common equity since the last rate case, and second, to provide an idea as to how much the cost of common equity has changed. In performing the updated analysis, Staff determined it was necessary to eliminate Cleco and Wisconsin Energy because both companies' stock prices are currently influenced by mergers and acquisitions. In order to allow for comparability between the two cases, Staff eliminated these companies from the 2012 study as well. After updating the multi-stage DCF analysis, Staff's multi-stage cost of equity estimate is 7.02% to 7.81% (w/o Cleco and Wisconsin Energy) (*see* Schedules 15-1 to 15-3). This compares to the multi-stage DCF analysis in the KCPL's 2012 rate case that indicated the cost of equity was 8.03% to 8.77% after eliminating Cleco and Wisconsin Energy from the proxy group results. Consequently, the updated multi-stage DCF analysis of the same proxy group using a consistent perpetual growth rate shows a cost of equity decrease of approximately 100 basis points since 2012.

vii. Backdating of Multi-Stage DCF Analysis on the Current Proxy Group Cases

In order to test whether the implied decrease in the cost of common equity from the proxy group in KCPL's 2012 rate case is reliable, Staff also decided to backdate a cost of common equity estimate of the current proxy group. Again, because the perpetual growth rate should not change much, simply using stock prices for the current proxy group from the 2012 period and using the projected long-term growth rates at the time for the first stage, provides a reasonable estimate of what the implied cost of equity used was at the time for the current proxy group.

Finding historical stock prices is not difficult as this is available from many sources online. However, looking back to 2012 and finding projected growth rates at the time is usually a challenge. However, because Staff currently has an upgraded subscription to SNL Financial and because SNL Financial maintains a database of this information, Staff was able to perform this analysis. Staff's backdated multi-stage DCF analysis of the current proxy group, with the exception of Ameren and PNM Resources because of financial difficulties they had at the time unrelated to their regulated utility operations, shows that the cost of equity estimate would have been approximately in the 8.23% to 8.84% range (*see* Schedules 16-1 to 16-3). This compares to a current cost of equity estimate of 7.18% to 7.96% if Ameren and PNM Resource are removed. Consequently, this supports an implied cost of equity reduction of approximately an 88-105 basis point range since KCPL's last rate case.

viii. Preference for GDP Growth

Although Staff is confident that investors do not expect that utilities' per share growth rates can grow at the same rate of nominal GDP in the long-run, Staff recognizes that even customer ROR witnesses have been willing to accept this assumption for purposes of estimating the cost of equity. Consequently, Staff will provide a cost of equity indication using this simplified approach.

Projected GDP growth is available from a variety of sources and the Energy Information Administration (EIA) publishes many of these in its Annual Energy Outlook. Not only does EIA publish near-term projected GDP growth rates, but it also publishes projected GDP growth rates over very long time periods. Because economists are projecting these growth rates over very long time periods, such growth rates represent economists' current estimates of what they believe the U.S. economy's long-run sustainable growth rate may be, since it is impossible to take into consideration many specific economic issues when projecting these long-term growth rates. These projected long-term growth rates in U.S. GDP are consistent with the current low interest rate environment, which provide signals that the U.S. economy will not return to the growth it achieved during the last century. This is quite logical considering the maturity of the U.S. economy. The projected economic growth rates are shown below:[45]

Table CP1. Comparisons of average annual economic growth projections, 2012-40

Projection	Average annual percentage growth rates 2012-2015	2012-2025	2025-2040	2012-2040
AEO2014 (Reference case)	2.6	2.5	2.4	2.4
AEO2013 (Reference case)	2.6	2.6	2.4	2.5
IHSGI (May 2013)	2.6	2.5	2.4	2.5
OMB (January 2014)[a]	2.7	2.6	–	–
CBO (February 2014)[a]	2.6	2.5	–	–
INFORUM (November 2013)	2.4	2.6	2.3	2.4
Social Security Administration (August 2013)	3.0	2.7	2.2	2.4
IEA (2013)[b]	2.6	2.8	–	2.4
ExxonMobil	–	2.5	2.2	2.4
OEG (January 2013)	2.7	2.7	2.5	2.6

-- = not reported or not applicable.
[a]OMB and CBO projections end in 2024, and growth rates cited are for 2012-24. AEO projections end in 2040.
[b]IEA publishes U.S. growth rates for certain intervals: 2011-15 growth is 2.6%, 2011-20 growth is 2.8%, and 2011-35 growth is 2.4%.

In each case in which the sources do not project a nominal GDP growth rate, Staff recommends adding a GDP price deflator of 2.0%, which is the CBO's prediction of long-term inflation and also the inflation rate which is targeted by the Federal Reserve. Considering the fact that a perpetual growth rate is intended to measure the long-run trend growth rate supported by the long-term fundamentals of the U.S.'s mature economy, Staff believes the most relevant projections from the table above are for the period 2025 through 2040. Staff recommends using the mid-point of the real GDP range of 2.2 to 2.5%, which is 2.35%. Compounding the expected GDP price deflator of 2.0% with the long-term real GDP growth of 2.35%, results in long-term nominal GDP growth of approximately 4.40%. When using a 4.4% GDP growth rate in Staff's multi-stage DCF results in a cost of equity estimate of approximately 8.28% for the broad proxy group and 8.18% for the refined proxy group.

G. Tests of Reasonableness

Staff has tested the reasonableness of its DCF results, both by use of a CAPM analysis and consideration of other evidence.

[45] Energy Information Administration's *2014 Annual Energy Outlook*, p. CP-2.

1. The CAPM

The CAPM is built on the premise that the variance in returns is the appropriate measure of risk, but only the non-diversifiable variance (systematic risk) is rewarded. Systematic risks, also called market risks, are unanticipated events that affect almost all assets to some degree because the effects are economy wide. Systematic risk in an asset, relative to the average, is measured by the Beta of that asset. Unsystematic risks, also called asset-specific risks, are unanticipated events that affect single assets or small groups of assets. Because unsystematic risks can be freely eliminated by diversification, the reward for bearing risk depends on the level of systematic risk. The CAPM shows that the expected return for a particular asset depends on the pure time value of money (measured by the risk free rate), the reward for bearing systematic risk (measured by the market risk premium), and the amount of systematic risk (measured by Beta). The general form of the CAPM is as follows:

$$k = Rf + \beta\ (Rm - Rf)$$

Where:	k	is the expected return on equity for a security;
	Rf	is the risk-free rate;
	β	is Beta; and
	Rm - Rf	is the market risk premium.

For inputs, Staff relied on historical capital market return information through the end of 2013. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending February 28, 2015; that figure was 2.78%. For beta (β), Staff relied on estimates directly calculated through an Excel spreadsheet designed specifically to be used with the SNL database of market and financial information. Although Staff is no longer using Value Line's published betas for purposes of its CAPM analysis in its direct testimony, because Value Line is used by many retail investors, Staff still believes Value Line's beta calculation methodology should be considered when performing a CAPM analysis. Because estimating beta is a matter of having access to financial data and performing statistical calculations, unless a financial services provider has a proprietary adjustment they make to their beta calculation, understanding the methodology used by a financial provider allows an analyst to approximately replicate betas of that provider. Fortunately, this is the case for Value Line's beta calculation methodology. Consistent with Value Line's approach to calculating beta, Staff used 5-years of historical weekly returns of the subject company and the New York Stock Exchange (NYSE) index. The covariance of the weekly returns on the NYSE index and the weekly returns on the subject company is divided by the variance of the weekly returns on the NYSE index to determine raw beta (unadjusted beta). Staff then adjusted the raw beta using the Blume adjustment formula as used by Value Line: Adjusted Beta = (.35 + .67(Unadjusted Beta)) (*see* Schedule 17).

The average beta for the broader proxy group was 0.77 and 0.76 for the refined proxy group. For the market risk premium (Rm – Rf) estimates, Staff relied on the historical difference between earned returns on stocks and earned returns on bonds.[46] The first risk premium was based on the long-term arithmetic average of historical return differences from 1926 to 2013 – 6.20 %. The second risk premium was based on the long-term geometric average of historical return differences from 1926 to 2013 – 4.64%. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.58% and 6.37%, respectively for the broad proxy group, and 7.46% and 6.28% for the refined proxy group.

These cost of common equity results support the reasonableness of Staff's cost of equity estimates derived from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low (at levels last experienced in the early 1960s) and that the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 6 to 7 percent range for utility stocks. In fact, as Staff will explain in its other tests of reasonableness, these cost of equity estimates are consistent with common sense tests.

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows an objective test of individual analyst's cost of equity estimates. Because this method is suggested in a textbook[47] used for the curriculum for Chartered Financial Analyst ("CFA") Program, Staff believes this method is free of any bias from those involved in utility ratemaking. It is also a useful test because it is very

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[46] From Duff & Phelps *2014 Valuation Handbook: A Guide to the Cost of Capital.*

[47] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 54.

straightforward and limits the risk premium to a 100 basis point range. The cost of equity is estimated by simply adding a risk premium to the yield-to-maturity ("YTM") of the subject company's long-term debt. Based on experience in the U.S. markets, the typical risk premium is in the 3% to 4% range. Considering that this is based on general U.S. capital-market experience and that regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the three months ended 2015, "A" rated and "Baa" rated 30-year utility bonds had average yields of 3.75% and 4.60% respectively.[48] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common equity between 6.75% and 7.60%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 7.75% and 8.60%.

These simple, straight-forward tests of reasonableness of cost of common equity estimates provide a common sense check on whether a cost of common equity estimate is logical considering the bid up of utility bonds and stocks in the last several years. As a point of reference, and also evidence that the Commission should lower its authorized return from the 9.7% to 9.8% range it allowed in 2012, the cost of equity indications from this straight-forward test in the KCPL rate case were as follows: 7.92% to 8.52% using a 3% risk premium and 8.92% to 9.52% using a 4% risk premium. The implied decline in the cost of common equity from rate cases in 2012 using this simple, straight-forward test is as much as 117 basis points.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using average authorized returns published by Regulatory Research Associates (RRA) to test the reasonableness of its allowed ROE. To the extent the Commission chooses to use RRA data again in this case, Staff believes the Commission should have information on allowed ROE's since 2012.

According to RRA, the electric utility companies' average authorized return on equity for the 2014 calendar year was 9.92% (based on 37 decisions) compared to a 2013 calendar year average of 10.02 %.[49] Excluding the effect of the surcharge/rider generation cases in Virginia,

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[48] BondsOnline.com, pursuant to a subscription agreement Staff has with BondsOnline.

[49] RRA, Regulatory Focus – Major rate case decisions (January-December 2014) - October 10, 1014: 2014 data includes four surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia

the average allowed electric ROEs were 9.76% in 2014 and 9.80% in 2013. This compares to an average allowed electric ROE of 10.17% in 2012.

In order to provide more specific information on the allowed ROE's by type of electric utility operations, Staff determined the allowed ROEs that were given to integrated electric utility companies. Staff excluded allowed ROEs that were determined for dockets not involving a full general rate case (i.e. rider only cases). Staff also continued to exclude the aforementioned Virginia rate cases. The average allowed ROEs for integrated electric utilities were 9.95% to 9.96% for the 2014 and 2013 calendar years. This compares to an average allowed ROE of 10.10% in 2012.

As a further refinement, Staff also evaluated allowed ROE information for only cases that were fully-litigated, as in these cases one would expect that each issue is determined based on its own merits. Allowed returns determined in context of a settled case are not as reliable because parties make adjustments to other elements of the ratemaking formula in order to arrive at an overall reasonable number. It has been Staff's experience, that some companies do not want a lower ROE published in a settlement because this is a headline number. Consequently, companies may compromise on a more obscure area of the rate case in order to have a higher ROE published in the settlement. Allowed ROEs for fully-litigated cases were 10.05 % and 9.96% for the 2014 and 2013 calendar years. This compares to an average allowed ROE of 10.10 % in 2012.

The allowed ROE information does not seem to provide any clear trends, but Staff believes the economic and capital market conditions clearly support a lower allowed ROE than the 9.7% and 9.8% the Commission authorized in 2012.

H. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover KCPL's prudent cost of service, which includes an allowed ROR. Using widely-accepted methods of financial analysis, Staff believes the cost of

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statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects.

common equity has declined by up to 125 basis points since 2012. Although this would justify an even larger reduction to the 2012 allowed ROEs than Staff's recent recommended reduction of 25 to 75 basis points in Ameren Missouri's pending rate case, considering the pullback in utility stock prices since February 2015, Staff believes the implied cost of equity decline using stock prices and data from December 2014 and January 2015 is slightly overestimated, but still higher than the estimated decline in the Ameren Missouri rate case.

Consequently, Staff recommends the Commission reduce its authorized ROE for KCPL to anywhere between 9.0% to 9.5% to at least partially share the reduced cost of equity with ratepayers. Given that the cost of capital is as real a cost as any other cost of service, reducing this cost in the ratemaking formula is consistent with the principles of cost of service ratemaking. Using this recommended allowed ROE results, the weighted average cost of capital for KCPL is in the range of 7.41% to 7.66% (*see* Schedule 18). This rate was calculated by applying an embedded cost of long-term debt of 5.55%, preferred common stock return of 4.29% and an allowed return on common equity range of 9.0% to 9.50% to a capital structure consisting of 50.31%, 0.55% preferred stock common equity and 49.14% long-term debt. Because there appears to be some concern in setting an allowed return on equity based on a reasonable estimate of the cost of equity, Staff recommends the Commission set the allowed ROE at 9.25% in this case. Although this is above what Staff estimates to be the cost of equity to be in the current capital market environment, this allowed ROE would balance the concern about the impact of a lower allowed ROE on investors' view of Missouri's regulatory environment, while still passing along the benefit of lower capital costs to ratepayers.

Staff Expert/Witness: Zephania Marevangepo

VII. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff recommends plant-in-service ("plant") and accumulated depreciation reserve ("reserve") balances be based on actual booked amounts as of the end of the Update Period, December 31, 2014, except as discussed in the Depreciation section of this Report. This includes plant additions that have occurred since the test year ending March 31, 2014, and the related depreciation reserve balances. At the time of the True-up audit, adjustments to the plant balances Staff used for its direct filing will be updated to include amounts for plant additions that have become fully operational and used for service as of May 31, 2015, the ending point of the True-up period. Staff will also make a true-up adjustment to update for depreciation reserve balances related to those additions. Plant must be "fully operational and used for service," before it is appropriate to reflect that plant and its associated reserve in rates.

The plant for KCPL for the period ending December 31, 2014, is identified on the Plant Accounting Schedule, Schedule 3, and the accumulated depreciation reserve as of that date is identified in the Depreciation Reserve Accounting Schedule, Schedule 6.

KCPL has made adjustments to the plant reserve balances to account for retirement work in progress (RWIP). RWIP is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage. KCPL removed the retired plant and related depreciation reserve from its plant and reserve account balances as of the retirement dates. However, as of December 31, 2014, KCPL had not removed the related reserve amounts associated with cost of removal and salvage accruals calculated for the retired plant included in the RWIP balance. While the actual plant is retired and removed from plant balance and the related reserve, the plant has not been physically disassembled so the cost of removal and salvage components of depreciation are still included in the reserve. As a result, KCPL's books overstate the reserve for this retired plant. Because the plant was removed from rate base it was necessary to make a corresponding adjustment to remove the amounts associated with the retired plant from the reserve balances, including the cost of removal and salvage amounts. Staff included a line item in the Accumulated Depreciation schedule, identifying the RWIP associated with Production, Transmission, Distribution, and General Plant.

Staff requested the plant and reserve amounts by FERC account and, in the case of the production facilities, by individual power plant. KCPL and Staff personnel verified the actual plant and reserve balances directly back to KCPL's books and records. KCPL uses an accounting package for plant records called Power Plant. Staff was able to substantiate the amounts provided by KCPL in data requests directly back to the Power Plant record system.

Staff also made an adjustment to include amortization of intangible plant for assets that KCPL has paid for the right to use or operate such as software licenses, but that KCPL does not legally own. Accumulated amortization is recorded for these intangible assets on an individual basis, and amortization ceases when the book value reaches zero. The amortization rate was set for each account using the depreciation rate of assets with the same classification. Adjustments E-237.1 and E-242.1 reflect the amortization of Intangible Plant for KCPL.

The following table identifies KCPL and GMO electric utility generation resources:

Load	Unit	Year Completed	Estimated 2014 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	2010	482(a)	Coal
	Wolf Creek	1985	549(a)	Nuclear
	Iatan No. 1	1980	499(a)	Coal
	LaCygne No. 2	1977	341(a)	Coal
	LaCygne No. 1	1973	368(a)	Coal
	Hawthorn No. 5(b)	1969	564	Coal
	Montrose No. 3	1964	176	Coal
	Montrose No. 2	1960	164	Coal
	Montrose No. 1	1958	170	Coal
Peak Load	West Gardner Nos. 1-4	2003	311	Natural Gas
	Osawatomie	2003	77	Natural Gas
	Hawthorn Nos. 6 and 9	1997, 2000	227	Natural Gas
	Hawthorn No. 8	2000	79	Natural Gas
	Hawthorn No. 7	2000	78	Natural Gas
	Northeast Black Start Unit	1985	2	Oil
	Northeast Nos. 17-18	1977	97	Oil
	Northeast Nos. 13-14	1976	91	Oil
	Northeast Nos. 15-16	1975	89	Oil
	Northeast Nos. 11-12	1972	96	Oil
Wind	Spearville 2 Wind Energy Facility (c)	2010	15	Wind
	Spearville 1 Wind Energy Facility (d)	2006	31	Wind
Total KCP&L			**4,493 MWs**	

continued on next page

Load	Unit	Year Completed	Estimated 2014 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	2010	159(a)	Coal
	Iatan No. 1	1980	128(a)	Coal
	Jeffrey energy Center Nos. 1, 2 and 3	1978, 1980, 1983	172(a)	Coal
	Sibley Nos.1, 2 and 3	1960, 1962, 1969	463	Coal
	Lake Road Nos. 2 and 4	1957, 1967	115	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	2005	303	Natural Gas
	Crossroads Energy Center	2002	307	Natural Gas
	Ralph Green No. 3	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	1975-1979	247	Natural Gas/Oil
	Lake Road No. 5	1974	67	Natural Gas/Oil
	Lake Road Nos. 1 and 3	1951, 1962	16	Natural Gas/Oil
	Lake Road Nos. 6 and 7	1989, 1990	42	Oil
	Nevada	1974	18	Oil
Total GMO			**2,108 MWs**	
Total Great Plains Energy			**6,601 MWs**	

Source: GREAT PLAINS ENERGY INC. 10-K December 31, 2013, page 22 and December 31, 2014, page 23

a. Share of a jointly owned unit.
b. In 2001, a new boiler, air quality control equipment and an uprated turbine was place in service at the Hawthorn Generating Station. [The unit was returned to commercial operation in June 2000following a 1999 explosion.
c. The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 15 MW pursuant to SPP reliability standards.
d. The 100.5 MW Spearville Wind Energy Facility's accredited capacity is 31 MW pursuant to SPP reliability standards.

Staff Expert/Witness: Joel A. Molina

B. La Cygne Environmental Retrofit Project

KCPL owns 50 percent of the La Cygne Generating Station. Kansas Gas and Electric Company, a wholly owned subsidiary of Westar Energy, Inc. ("Westar") owns and controls the other 50 percent. KCPL and Westar have entered into an ownership agreement which gives KCPL the authority and responsibility to operate this station. La Cygne has two coal-fired units. The La Cygne Unit 1 is rated at 812 MW and was placed in commercial operation in 1973. The La Cygne Unit 2 is rated at 717 MW gross, and was placed in service in 1977.

KCPL anticipates completing its La Cygne Environmental Retrofit Project ("Project") -- the installation of wet scrubbers, baghouses, and a common dual-flue chimney for both Units 1 and 2, and an SCR system, low-NOx burners and an over-fire air system for Unit 2 at the La Cygne Generating Station —during the pendency of this rate case. Project completion is required no later than June 1, 2015. This is the required date for the plant to be in compliance with applicable environmental regulations and a consent decree between KCPL and the U.S. Environmental Protection Agency (EPA). Without the Project upgrades, KCPL would have to shut down La Cygne at the end of May 2015, until the upgrades are complete.

In August 2011, the Kansas Corporation Commission issued an order ruling that KCPL's decision to undertake the La Cygne Environmental Retrofit Project to comply with environmental regulations was prudent and KCPL's $1.23 billion project cost estimate was reasonable. In the proceeding before the Kansas Corporation Commission (Docket No. 11-KCPE-581PRE) KCPL presented its assessment of a large number of alternative configurations and fuel mixes for the La Cygne units and concluded an environmental retrofit was the least-cost alternative. The total Project budget includes contingency, but excludes Allowance for Funds Used During Construction ("AFUDC") and capitalized property taxes. KCPL's 50 percent share of the total budgeted cost is approximately$600 million, with its Missouri jurisdiction currently projected to be allocated approximately $335 million.

KCPL, as the operating partner of the La Cygne Generating Station, is managing the schedule and budget for the project through its oversight and monitoring of the activities of La Cygne Environmental Partners, a joint venture formed by Kiewit Power Constructors Co. and Sargent & Lundy, L.L.C., which is the contractor under the competitively-bid engineer-procure-construct ("EPC") contract KCPL entered into to build the Project. Black & Veatch is the Owner's (KCPL's) Engineer.

Staff is in the process of conducting a construction audit of the La Cygne Environmental Retrofit Project costs that KCPL has sought to include in its rate base and cost of service in this rate case. Staff will provide the results of its construction audit during the true-up phase of this rate case. Staff has included in Staff's Accounting Schedules in its direct filing an estimate of the impact the addition of this plant will have on KCPL's overall revenue requirement, when the plant is used and useful, and meets Staff's in-service criteria. Staff and KCPL are currently seeking agreement on in-service criteria to apply to the Project.

In Staff's construction audit, it will review for prudence and determine the appropriate level of construction costs related to the La Cygne Environmental Retrofit Project to be used for purposes of setting KCPL's rates, and to provide an independent and objective assessment of KCPL's performance as it relates to these specific construction project activities.

During the course of the Project, Staff has made visits to the Project construction site, met with KCPL construction personnel, reviewed responses to Staff data requests and reviewed monthly project status reports. Since October 2011, KCPL has been submitting monthly status reports on the Project to the Kansas Corporation Commission in Compliance Docket No. 12-KCPE-258-CPL. Each report covers actual cost data for the Project as well as schedule and metric data. Each monthly report also includes a written description of the current status of the Project.

KCPL reported in its "Investor Presentation March 2015" filed with the Securities and Exchange Commission in its March 18, 2015, Form 8-K filing that the Project, as of March 18, 2015, was on schedule and within budget.

Staff Expert/Witness: Shawn E. Lange and Charles R. Hyneman

C. Material and Supplies

Staff's recommended treatment of materials and supplies is to examine each account individually in order to determine an appropriate level that most accurately reflects the ongoing future investment costs of a particular account that should be included in rate base. Materials and supplies represent an investment in inventory for items such as spare parts, electric cables, poles, meters, and other miscellaneous items used in daily operations, maintenance and construction activities by KCPL to maintain and build KCPL's production facilities and electric system. Because the account balances varied greatly depending on each individual account, Staff reviewed the balances for each account for materials and supplies individually on a monthly basis to determine whether trends within an individual account existed over time. Staff reviewed the monthly balances for materials and supplies accounts from April 2013 to December

2014. If an upward or downward trend was detected, then Staff used the ending balance for that account. If there was no discernible trend, then an average of the accounts is used, typically a 13-month average, and determined to be the most appropriate measure of the ongoing investment level for that account. Staff examined the accounts individually and determined which methodology, 13-month average or ending balance, was the most appropriate measure to accurately predict the ongoing future of a particular account that should be included in rate base (Accounting Schedule 2).

Staff Expert/Witness: Joel A. Molina

D. Prepayments

Staff's recommended treatment of prepayments is to examine each prepayment account individually in order to determine an appropriate measure that most accurately predicts the ongoing future investment costs of a particular prepayment account, and then to include the appropriate level of prepayments in KCPL's rate base. Prepayments are expenses a company pays in advance of use that have not been incurred. Since there are investment costs incurred by the utility when it prepays expenses, the company is allowed to earn a return on these amounts through inclusion in rate base. For example, KCPL pays for a property insurance policy to protect its assets in advance of the coverage period. Accordingly, the cost of that insurance policy is a prepayment and included in rate base. Prepayments are treated as an asset and are reflected in the utility's rate base. As the prepayments are consumed, an amount is charged to an expense account in the income statement. Staff included amounts in its rate base for all prepayments that KCPL requires to provide electric utility service to its customers. Staff examined all of KCPL's prepayment account balances from April 2013 to December, on a month-by-month basis. Based on this review, and the variability in the monthly account balances, Staff determined the prepayment levels to be included in KCPL's rate base. For accounts where there was no discernible upward or downward trend in the monthly balances, Staff calculated an average based on balances for the 13-months ending December 31, 2014. For accounts where a noticeable upward or downward trend was present, Staff used the most recent account balance (December 31, 2014).

Staff did not include prepayments related to gross receipts taxes. While KCPL accounts for gross receipts taxes as a prepayment, these costs are actually paid in arrears and as a result, Staff excluded these taxes from prepayments. A detailed explanation of gross receipts taxes is included in the "Removal of Gross Receipts Taxes from Test Year Revenues" section of this report. The cash flow impact on KCPL for gross receipts taxes is reflected in Staff's Cash Working Capital calculation as shown on Accounting Schedule 8. The Commission should base its awarded revenue requirement on Staff's recommended appropriate measure of prepayments added to KCPL's rate base, indicated in Accounting Schedule 2. Staff further recommends that prepayment investment costs should not include any amounts for gross receipts taxes.

Staff Expert/Witness: Joel A. Molina

E. Cash Working Capital

Cash Working Capital (CWC) is the amount of cash necessary for a utility to pay the day-to-day expenses incurred to provide utility services to its customers. Cash inflows from payments received by the company from its customers for the provision of utility service and cash outflows for expenses paid by the company in providing that utility service are analyzed using a lead/lag study. KCPL and Staff are using the same expense lags agreed to by both parties in the 2012 rate case. Staff has reviewed the direct testimony of KCPL witness Ronald A. Klote and is using the same revenue lags as outlined on pages 29 through 31 of his testimony.

When the company expends funds to pay an expense before its customers provide the cash, the shareholders are the source of the funds. This cash represents a portion of the shareholders' total investment in the company. The shareholders are compensated for the CWC funds they provide by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the funds they have invested.

Customers supply CWC when they pay for electric services received before the Company pays expenses incurred to provide that service. Utility customers are compensated for the CWC they provide by a reduction to the utility's rate base. A positive CWC requirement indicates that, in the aggregate, the shareholders provided the CWC. This means that, on average, the utility paid the expenses incurred to provide the electric services to its customers before those customers had to pay the company for the provision of these utility services. A negative CWC requirement indicates that, in the aggregate, the utility's customers provided the CWC. This means that, on average, the customers paid for the utility's electric services before the utility paid the expenses that the utility incurred to provide those services.

Cash Working Capital Schedule 8 identifies the amount of cash working capital to be reflected in KCPL's cost of service. Staff's CWC analysis results are reflected on the Rate Base Accounting Schedule 2 in the section "Add to Net Plant In Service." Staff's CWC analysis results used in the Schedule 2 section titled "Subtract From Net Plant" reflect the amounts of Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

Staff Expert/Witness: V. William Harris

F. Fuel Inventories

1. Coal Inventory

The amount Staff included in KCPL's rate base for coal inventory is based on the results obtained from Staff's production cost model ("fuel model"). Staff used its fuel model to determine the appropriate mix of generation unit and purchased power utilization to match the normalized native load for KCPL. In doing so, Staff obtained from the fuel model an annual amount of tons of coal burned by each coal-fired generation unit during the normalized updated test year. Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. Staff then multiplied this average daily burn by KCPL's recommended number of burn days of coal inventory for each generation unit and added an estimated level of basemat coal. Basemat coal is the bottom portion of the coal pile that is difficult to burn in the generating facilities because of the contamination of moisture, soil, clay, and other contaminants. Staff then multiplied the resulting normalized level of inventory for each unit by the delivered cost per ton of coal for use at that unit. The resulting annual coal costs for each unit were then aggregated. The aggregated amount was multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown in Rate Base – Schedule 2.

Staff Expert/Witness: Karen Lyons

2. Nuclear Inventory

To determine the amount to include in rate base for KCPL's nuclear fuel inventory, Staff used an 18-month average of the value of nuclear fuel that was contained in the fuel core of the Wolf Creek nuclear generating unit. Since the Wolf Creek unit is refueled every 18 months, this

18-month time period reflects the average nuclear fuel inventory value during a complete nuclear fuel usage cycle at Wolf Creek. This approach is consistent with the method used by KCPL to calculate the revenue requirement in this case. Staff's recommended level of nuclear fuel inventory for KCPL is shown on Schedule 2 of Staff's Accounting Schedules.

Staff Expert/Witness: Karen Lyons

3. <u>Oil and Fuel Additive Inventories</u>

Staff used 13-month averages to determine the inventory levels for oil, lime, limestone, ammonia, and powder activated carbon inventories as of December 31, 2014. Staff priced out the various inventories using the latest pricing or the actual monthly dollar levels of inventory. Use of 13-month average inventory levels is appropriate in that it reflects KCPL's actual experience for the entire 12-month test year period by including a beginning inventory and an ending inventory. For example, if the test year were a calendar year it would begin with January 1 and end with December 31. A 13-month average reflects the entire year by using the December 31 (January 1) beginning balance and including each subsequent month-ending balance through the end of the year (December 31). Twelve month-ending balances from January 31 through December 31 do not accurately reflect the KCPL's actual experience because they ignore the impact of the period from January 1 through January 30. When inventory levels fluctuate from month-to-month, as they do with fuel stocks, a 13-month average is used to smooth out those levels. Staff's inventory levels for coal, nuclear, oil, limestone, and ammonia are shown in Rate Base – Schedule 2. Staff's approach is consistent with the method used by KCPL to calculate the revenue requirement in this case.

Staff Expert/Witness: Karen Lyons

G. Customer Deposits

Staff's recommended treatment of customer deposits is to deduct the most current customer deposit balance, as reflected in the Missouri jurisdictional total, from KCPL's rate base. Customer deposits are the funds required to be provided by certain customers taking electrical service from KCPL. These funds are deducted from KCPL's rate base because these funds are cost-free funds received by KCPL. The amount reflected for customer deposits on Accounting Schedule 2, Rate Base, is a six (6) month average for the period July 2014 to

December 2014. The balance reflected on the Rate Base Schedule is the Missouri jurisdictional total for customer deposits. The six (6) month average was used because the account balance fluctuated over that period. In addition to the amount deducted from rate base for customer deposits, an amount for interest on customer deposits has been included as an adjustment to the income statement under Account 903 (Accounting Schedule 9). Customers are paid interest for the use of the funds they provide to KCPL on a cost-free basis, and that interest expense is included as an expense in the revenue requirement calculation discussed in more detail in the "Customer Deposits - Interest Expense" section below.). The Commission should base its awarded revenue requirement on Staff's recommended deduction of the most current balance for Customer Deposit funds reflected in the Missouri jurisdictional total from KCPL's rate base.

Staff Expert/Witness: Joel A. Molina

H. Customer Advances

Staff's recommended treatment of customer advances is to deduct the most current customer advances balance, as reflected in the Missouri jurisdictional total, from KCPL's rate base. Customer advances are funds typically provided by building and real estate developers in KCPL's service territory in order to ensure that KCPL builds electric infrastructure in areas that have potential for future development. These advances are also used by the utility to establish electric service for potential future customers without investing a substantial amount of money at the risk of the utility and its other customers. Customer advances are included in the rate base as an offset in the same way customers deposits are used as an offset, reducing the amount of overall investment that customers must supply as a return to the utility. The amount of customer advances reflected on Accounting Schedule 2, Rate Base, represents the last known balance of the account (balances ending December 31, 2014) of KCPL's Missouri jurisdictional contributions. The Commission should base its awarded revenue requirement on Staff's recommended deduction of the most current balance for customer advances, reflected in the Missouri jurisdictional total, from KCPL's rate base.

Staff Expert/Witness: Joel A. Molina

I. Iatan Construction Accounting Regulatory Assets

During the creation and execution of KCPL's Experimental Regulatory Plan for the construction of Iatan 2, adding pollution control equipment to Iatan 1, and other investments, the Commission authorized KCPL to book certain costs into regulatory asset accounts for potential recovery in future general rate cases. Below is a table that identifies the generating unit, the cost associated with that generating unit the Commission authorized KCPL book in a regulatory asset account, and the time period over which the costs were collected in the regulatory asset account:

Owner	Generating Unit	Expense Type	Accumulation Period
KCPL	Iatan 1 and Common	Depreciation, Carrying Cost, No O&M	May 1, 2009 – May 4, 2011
KCPL	Iatan 2	Depreciation, Carrying Cost, O&M	August 26, 2010 – May 4, 2011

Pursuant to the Commission's Order of June 10, 2009, in Case No. ER-2009-0089, approving the 2009 Stipulation and Agreement, the Commission authorized KCPL to create a regulatory asset account for recording the depreciation and carrying costs for the Iatan Unit 1 AQCS and Iatan common facilities appropriately recorded to electric plant-in-service, but the amount in that account was not included in KCPL's rate base in that case. Pursuant to the Commission's July 28, 2005, Report and Order approving the Stipulation and Agreement filed in Case No. EO-2005-0329, the Commission authorized KCPL to create a regulatory asset account for booking the depreciation, carrying costs, and other operating expenses and credits for Iatan Unit 2 subsequent to its commercial in-service date of August 26, 2010.

For purposes of inclusion in rate base, Staff reflected the balances of these regulatory asset accounts as of December 31, 2014, the end of the test year update period the Commission ordered in it procedural schedule order of in this case of December 12, 2014.

The Iatan Unit 1 and Common regulatory asset capturing construction accounting from May 1, 2009, through December 31, 2010, the true-up cutoff in Case No. ER-2010-0355, is referred to as "Iatan 1 - Vintage 1." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and amortized over 26 years.

The Iatan Unit 1 and Common regulatory asset capturing construction accounting from January 1, 2011, through May 4, 2011 (the effective date of new rates in Case No.

ER-2010-0355), is referred to as "Iatan 1 - Vintage 2." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and amortized to expense over 24.3 years (26 years reduced by the number of months since the date rates set in Case No. ER-2010-0355 took effect).

The Iatan Unit 2 regulatory asset capturing construction accounting from August 26, 2010, through December 31, 2010, the true-up cutoff in Case No. ER-2010-0355, is referred to as "Iatan 2 - Vintage 1." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and is amortized over 47.7 years.

The Iatan Unit 2 regulatory asset capturing construction accounting from January 1, 2011, through May 4, 2011, the effective date of rates in Case No. ER-2010-0355, is referenced to as "Iatan 2 - Vintage 2." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and amortized to expense over 46 years (47.7 years as authorized by the Commission, reduced by the number of months since the date rates set in Case No. ER-2010-0355 took effect).

The test year ending March 31, 2014 includes a full 12 months of amortization related to these regulatory assets, therefore no adjustment to expense is necessary.

Staff Expert/Witness: Keith Majors

VIII. Income Statement – Revenues

A. Rate Revenues

1. Introduction

This section describes how the Staff determined the level of KCPL Operating Revenues. Since the largest component of operating revenues result from rates charged to KCPL's retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates KCPL charges its Missouri retail customers for electricity may be appropriate.

One of the major tasks in a rate case is to determine the magnitude of any deficiency (or excess) between cost of service and operating revenues. Once determined, the deficiency (or excess) can only be corrected (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenue) prospectively. Operating Revenues are composed of Off-system Sales, Other Operating Revenue and Rate Revenue.

Rate Revenue - Test Year rate revenues consist solely of the revenues derived from KCPL's charges for providing electric service to its Missouri retail customers. KCPL's revenues are determined by each customer's usage and the (per unit) rates that are applied to that usage per unit rates established in KCPL's tariffs. In Missouri, different rates apply to different times of the year (summer vs. winter); different types of charges (demand, energy, etc.); and to customers in different rate classes.

Staff Expert/Witness: Robin Kliethermes

2. <u>The Development of Rate Revenue</u>

Staff's recommended treatment of developing Rate Revenue is to determine annualized, normalized billing units and revenues by rate classes during the Test Year of April 1, 2013 - March 31, 2014, updated through December 31, 2014, for rate switchers and customer growth.

Staff's adjustments to KCPL's Missouri jurisdiction billing units and rate revenues are based upon information that is "known and measurable" through the end of the Update Period (December 31, 2014). The two major categories of revenue adjustments are known as "normalization" and "annualization." Normalizations address Test Year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect, e.g., events like the Test Year weather. Annualizations are adjustments that re-state the Test Year results, updated through December 31, 2014, for rate switchers and customer growth, as if conditions known at the end of the Test Year had existed through December 31, 2014.

Not all adjustments affect both billing units and rate revenue. Not all rate classes are subject to all adjustments.

Staff Expert/Witness: Robin Kliethermes

3. <u>The Effect of the Weather Normalization on Rate Revenue</u>

To calculate weather-normalized revenue, Staff applied current rates to weather normalized usage provided by Staff witness Seoung Joun Won, PhD for the Residential Service ("RES"), Small General Service (SGS), Medium General Service (MGS), Large General Service (LGS), and Large Power Service (LPS). Staff's weather normalization revenue adjustment is equal to the difference between weather-normalized revenue and the Test Year revenue.

The weather normalization process assumes that weather has no effect on either the number of customers or on the fixed charges these customers currently pay. Weather variations only affect the energy usage of each existing customer and, thus, weather normalization only changes revenue directly related to usage.

Staff Expert/Witness: Robin Kliethermes

4. 365-Days Revenue Adjustment for Weather Sensitive Classes

Staff calculated a revenue adjustment for Missouri weather sensitive classes by allocating the amount of 365-Days adjustment proportionately to the appropriate revenue month weather-normalized usage for each class and then applying current rates. The difference between the 365-Days adjusted revenue and the current rate revenues is the 365-Days adjustment to revenue.

Staff Expert/Witness: Robin Kliethermes

B. Customer Growth in Usage

Staff adjusted usage and revenue through December 31, 2014, for the Missouri jurisdiction for customer growth to reflect the additional usage and rate revenues that would have occurred, if the number of customers taking service at the end of December 31, 2014 had existed throughout the entire Test Year using the kWh information provided by Staff witness Keith Majors.[50] Staff is still reviewing whether the three customers who moved from the LP class during the update period and into the LGS class should be handled through the growth adjustment as was currently done, or if the additional kWh should be added to the LGS class prior to any weather normalization or growth adjustment is performed. This issue will be addressed during true-up.

Staff Expert/Witness: Robin Kliethermes

[50] When the kWh was applied to class energy blocks based on the percent of energy in each block, the revenue that was calculated was slightly higher than the revenue that Staff witness Keith Majors had previously calculated. Staff adjusted kWh and revenues for the RES, SGS, MGS, and LGS rate classes only.

1. Customer Discounts

MPower: Peak load curtailment credits are paid to customers that agree to curtail a portion of their peak load when requested by KCPL. These discounts are assumed to be a benefit to all ratepayers and thus are not excluded from the determination of KCPL's revenues.

EDR: The Economic Development Rider ("EDR") provides for discounts to be "paid" to customers (in the form of credits on their electricity bill) who locate or expand operations in KCPL's service territory. EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule. These discounts are included in the determination of KCPL's revenues because fostering economic development is assumed to be a benefit to all ratepayers.

Staff Experts/Witnesses: Seoung Joun Won, Ph.D. and Robin Kliethermes

2. Weather Normalization

a. Weather Variables

Historical Data Used to Calculate Weather Variables – Each year's weather is unique; consequently, test year usage, hourly loads, revenue, and fuel and purchased power expense need to be adjusted to "normal" weather so that rates will be designed on the basis of normal weather rather than any anomalous weather in the test year. In the quantification of the relationship between test year weather and energy sales, Staff used weather observations for the test year of April 1, 2013, through March 31, 2014, from the Kansas City International Airport ("MCI") in Kansas City, Missouri.

As a measure of "normal" weather, Staff used a 30-year period of "climate normals" ("normals") published by the National Climatic Data Center (NCDC) of the U.S. National Oceanic and Atmospheric Administration ("NOAA"). According to NOAA, a climate normal is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[51] To conform to the NOAA's three consecutive decades for determining normal temperatures, Staff used observed maximum and minimum daily temperatures for the 30-year

[51] Retrieved on June 27, 2014, http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals.

period of January 1, 1981, through December 31, 2010. Therefore, Staff bases its calculations on the time period of the most recent climate normals produced by NCDC.[52]

Although the definition of normal weather is relatively simple, the actual calculations may be more complicated. Inconsistencies and biases in the 30-year time series of daily temperature observations occur if weather instruments are relocated, replaced, or recalibrated. Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. NOAA accounted for these anomalies in calculating the normal temperatures it published in July 2011.

Staff verified the adjustments for anomalies in the MCI time series by direct communication with NCDC, and through Staff's own review of the daily observations. According to NCDC, the serially-complete monthly minimum and maximum temperature data sets have been adjusted to remove all inconsistencies and biases due to changes in the associated historical database. Furthermore, Staff's review of NCDC's peer-reviewed, published paper[53] that explains the meteorological and statistical soundness of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies, and found it to be statistically sound.

Staff uses daily temperature observations to calculate normal weather values; however, NOAA's normals are monthly values. Staff adjusted the observed daily temperatures so that the monthly average temperatures calculated from these adjusted daily values are the same as the NCDC's serially-complete monthly temperature time series. Staff derived the daily mean temperature time series, daily two-day weighted mean temperatures, and normal daily temperatures from these adjusted daily temperatures.

Weather Variables - Weather fluctuates greatly from day-to-day; therefore, the MCI temperature variables required to weather-normalize sales are the test year actual temperatures and the 30-year normal two-day weighted daily mean temperatures. The day's daily mean temperature is generally defined as the simple average of the day's maximum daily temperature and minimum daily temperature. The daily two-day weighted mean temperature is calculated

[52] Retrieved on June 27, 2014, http://www ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data.
[53] Menne, M.J., and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, **22**, 1700-1717.

using the previous day's mean daily temperature with a one-third weight and the current day's mean daily temperature with a two-thirds weight.[54]

The calculation was done because in the KCPL service area yesterday's weather effects how electricity is used today. This is likely due to heat retention by the structures in the service area. For example, if today's temperature is mild, but yesterday's temperature was hot and the air conditioner was on, it is likely that the air conditioner will also be used today. Similarly, if yesterday's temperature was mild and air conditioning was not used, then if today's temperature is warmer, air conditioning may not be used until later in the day. Staff used the MCI daily two-day weighted mean temperature data series to normalize both class usage and hourly net system loads.

Calculation of "Normal Weather" - Staff used a ranking method to calculate normal weather estimates of daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating "normal extremes." Staff ranked the two-day weighted temperatures for each year of the 30-year history from hottest to coldest and then calculated the normal daily temperature values by averaging the ranked two-day weighted mean temperatures for each rank, irrespective of the calendar date.

The ranking results in the normal extreme being the average of the most extreme temperatures in each year of the 30-year normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth. Staff's calculation of daily normal temperatures is not the same as NOAA's calculation of smoothed daily normal temperatures. The test year temperatures do not follow smooth patterns from day to day, Staff calculated normal daily temperatures based on the rankings of the actual temperatures of the test year.

Staff Expert/Witness: Seoung Joun Won, Ph.D.

b. Weather Normalization

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature increases the demand for additional cooling, air conditioning, and fans, increases customers' consumption of electricity. As the

[54] To calculate the Dth day's two-day weighted mean temperature ($TWMT_D$), the current day's (D) daily mean temperature (DMT_D) is averaged with the prior day's (D-1) daily mean temperature (DMT_{D-1}), applying a 2/3 weight on the current day and 1/3 weight on the prior day: $TWMT_D = (2/3)\ DMT_D + (1/3)\ DMT_{D-1}$

temperature falls, the demand for additional heating, electric space heating for example, also increases customers' electricity consumption. Electric air conditioning and space heating is prevalent in KCPL's service territory; therefore, it follows that KCPL's electric load is linked and responsive to daily changes in temperature.

Staff used the load data of the Test Year of April 1, 2013, through March 31, 2014. December 2013 through March 2014 experienced temperatures colder than normal, resulting in electric energy usage above that which would have been expected under normal weather conditions. July 2013 through August 2013 experienced temperatures more mild than normal resulting in usage below that which would have been anticipated under normal conditions. The temperatures in the test year used by Staff deviated from normal, thus Staff performed a weather impact analysis.

Staff's model and methodology contained elements important in the class level weather normalization process: use of daily load research data to determine non-linear class specific responses to changes in temperature with the incorporation of different base usage parameters to account for different days of the week, months of the year, and holidays. The results of Staff's analysis were provided to Staff witness Robin Kliethermes to be used in the normalization of revenues for the RES, SGS, MGS, LGS and LPS classes.

Staff Expert/Witness: Seoung Joun Won, Ph.D.

c. 365-Days Adjustment to Usage

Staff calculated a normalization adjustment to KCPL's kWh usage to reflect a calendar year's (365 days) worth of usage. KCPL's customers' usage is measured, and rate revenue is collected over a period known as a revenue month, which is the interval that KCPL reads customers' meters and generates bills. A bill rendered for a given revenue month may charge for usage in parts of two calendar months. Revenue months take their names from the calendar month in which the customer's bill is rendered. For example, assume a customer's meter was read and usage determined on June 8 and then again on July 8 and that the bill was sent to the customer on July 15. The revenue month for this bill is July even though 22 days of the usage measured for this bill occurred from June 9 through June 30 and it contained only eight days of usage in July.

The length of a revenue month is dependent upon the interval between meter readings and does not necessarily have the same number of days that occur in a given calendar month of the same name; that is, a revenue month may have more than or less than the number of days for the same-named calendar month. For the example above, the usage is for 30 days (June 9 through July 8) even though the revenue month is July which has 31 days. When revenue month usage is totaled over the year, the resulting revenue year will include usage from the immediately prior calendar year and assign usage to the next calendar year, meaning a revenue year may contain more than or less than 365 days' usage. Therefore, since the costs and expenses are accounted over a calendar year, Staff calculates an annualization adjustment to bring the revenue year kWh into a 365 days interval. This adjustment stated in kWh is referred to as 365-Days Adjustment.[55]

Staff calculates the 365-Days Adjustment by subtracting the weather normalized revenue month kWh from the weather normalized calendar month kWh for the test year; the difference, or the 365-Days Adjustment, may be either positive or negative.

The 365-Days Adjustment for RES, SGS, MGS, LGS, and LPS were provided to Staff witnesses Robin Kliethermes who used the 365-Days Adjustment to adjust the revenues of the weather normalized class revenues months to the twelve months ended March 31, 2014.

Staff Expert/Witness: Seoung Joun Won, Ph.D.

C. Customer Growth

Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue, which would have occurred if the number of customers taking service at the end of the update period (December 31, 2014) had existed throughout the entire test year. Staff calculated customer growth for the Residential, Small General Service, Medium General Service, and Large General Service rate classes using customer levels as of December 31, 2014.

Staff Expert/Witness: Keith Majors

[55] Days adjustments are also known as adjustments to unbilled usage and unbilled revenues on financial statements.

D. Additional Revenues from Customer Growth During the Update Period

For this Direct Testimony filing, Staff updated all elements of revenue, expense, and rate base over the 12-month period ended March 31, 2014 test year level and for any known and measurable changes through December 31, 2014. For Residential and General Service (Small, Medium, and Large) retail customer groups, Staff employed the following method of computing the annualized level of increased revenue from customer growth at December 31, 2014. For each customer rate group, the customer level during each month of the test year is compared to the level as of December 31, 2014, and the monthly change in level is computed. This growth in customers is then multiplied by the weather-normalized revenue per customer experienced for that month of the test year. In this case, weather-normalized revenue was based on the 12-month period April 1, 2013 through March 31, 2014.

Staff's approach assumes that the revenue pattern experienced in each month of the test year will recur on a weather-normalized basis, factored up (or down) in accordance with the growth (or decrease) in customer numbers at December 31, 2014.

The only retail customer rate group for which this approach is not taken is the Large Power Service customers. With respect to Large Power Service customers, energy consumption and revenue patterns vary significantly across this group of customers, making it necessary to examine the history of each customer on an individual basis, and to adjust the test year revenue level accordingly. Staff witness Seoung Joun Won, Ph.D. addresses the Large Power Service revenue annualization. Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, General Service, and Large Power Service customers in order to provide the annualized level as of December 31, 2014. The retail customer growth adjustment other than Large Power Service is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-2.2.

Staff Expert/Witness: Keith Majors

E. Large Power Service (LPS) Adjustments

Staff determined annualized, normalized test year usage and revenues, updated through December 31, 2014 for rate switchers for the LPS class on an individual customer basis.

The adjustments are for the Test Year of April 1, 2013 – March 31, 2014. There were 81 customers in the LPS rate class at the beginning of the test year.

Each LPS customer uses significant amounts of electricity, and the class is heterogeneous in electric use and load factor; therefore, class sales and revenues were annualized on an individual customer account basis. LPS customer revenues were annualized for major growth or decline in kWh sales and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers active at the end of December 31, 2014.

Staff analyzed LPS customer data during the test year and through December 31, 2014. A data check for billing corrections was done prior to making any adjustments. Each LPS customer's individual monthly energy and demand use, measured over multiple years prior to the test year and the 12 months of the test year, were examined graphically to determine whether an adjustment was needed.

Four LPS customers' loads were adjusted due to abnormal usage in the test year. Additionally, through December 31, 2014, seven customers left the LPS class; therefore those customers' loads were annualized to reflect the loss.

Staff Expert/Witness: Seoung Joun Won, Ph.D.

F. Transmission Revenue-FERC Account 456

KCPL books transmission revenue to FERC Account 456. KCPL receives revenues from SPP on the following SPP tariff schedules:

- Schedule 2: Revenues related to reactive supply for generators connected to the transmission system
- Schedule 7: Revenues related to firm point to point transmission
- Schedule 8: Revenues related to non-firm point to point transmission
- Schedule 9: Revenue related to network integrated transmission
- Schedule 11: Revenues related to the base plan transmission upgrades

Although KCPL receives revenues from SPP based on all of the schedules listed above, a significant percentage of the transmission revenues received from SPP are from firm and non-firm point-to-point transmission and base plan transmission activities.

In its updated direct case, KCPL made an adjustment to reduce transmission revenue for the difference in KCPL's authorized FERC ROE of 11.1% and KCPL's proposed ROE in this case of 10.3%. KCPL also reduced revenues for region-wide transmission projects that are discussed in further detail in the section "Transmission Expense-FERC Account 565" in this report.

Staff analyzed KCPL's transmission revenue for the period of 2009 through 2014, and reviewed KCPL's proposed wholesale revenue adjustment. The wholesale revenue adjustment proposed by KCPL is the difference in KCPL's authorized FERC ROE of 11.1% and KCPL's proposed ROE in this case of 10.3%.

During its analysis, Staff compared KCPL's historical transmission revenues to its transmission expense. KCPL's transmission revenue for the 12-month period ended December 31, 2014 ** __________ ** over the 12-month period ended December 31, 2009. On the other hand, KCPL's transmission expense has ** __________ ** for the same period. The following chart reflects KCPL's historical transmission expense and revenues for the period of 2009-2014.

**

**

Although KCPL's revenues have decreased over the last six (6) years, the revenues did increase over the course of the test year period; the 12 months ended March 31, 2014. Since the

NP

SPP Integrated Market started on March 1, 2014, Staff recommends using the transmission revenues for the 12-month period ended December 31, 2014, as it is representative of operation of the current SPP Integrated Market. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment Rev-24.1.

As mentioned above, Staff reviewed KCPL's adjustment to reduce transmission revenues for the difference in KCPL's authorized FERC ROE of 11.1% and KCPL's proposed ROE in this case of 10.3%. KCPL received the transmission revenues from SPP for point to point and base plan upgrades. The wholesale transmission revenue adjustment is calculated using the Annual Transmission Revenue Requirement (ATRR) using KCPL's authorized FERC ROE of 11.1%, not the 10.3% equity rate of return. The ATTR is used by SPP to allocate revenues and expenses to all transmission owners and transmission customers of SPP. The transmission owners receive allocated revenues based on the ATTR and the transmission customers are charged for allocated costs based on the ATTR. The ATTR includes incentives such as allowing CWIP in the revenue requirement, ROE adders, etc. KCPL's authorized FERC ROE of 11.1% includes a ROE adder for being a member of an regional transmission organization (RTO) of 50 basis points.

Other SPP transmission owners submit the ATTR that may include the previously discussed incentives. KCPL will then receive its allocated share of the transmission costs that include incentives. Since no adjustment was made to its transmission expense for the incentives that are included in the costs KCPL receives from SPP, Staff did not reduce transmission revenues for the difference in KCPL's authorized FERC ROE of 11.1% and its proposed ROE of 10.3%.

Staff Expert/Witness: Karen Lyons

G. Ancillary Services

Ancillary services, also known as operating reserves, include Regulation-up, Regulation-down, Spinning Reserve, and Supplemental Reserve services. These services support the transmission of capacity and energy while maintaining the reliability of the transmission system. Regulation–up and Regulation-down maintains the balance between the generation and the load. Spinning and Supplemental reserve requires that an energy resource such as a power plant must be available in the event of an outage. Prior to March 1, 2014, KCPL was part of an Energy Imbalance Service market ("EIS") and self-designated ancillary services. On March 1, 2014, the SPP Integrated Marketplace began replacing the previous EIS market. Consequently, KCPL now purchases ancillary service from SPP and sells the services to SPP.

Staff annualized ancillary services for the period March 1, 2014, the date the IM market began, through December 31, 2014, the update period in this case. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment Rev-14.1. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

H. Transmission Congestion Rights

Transmission Congestion Rights (TCR) are an energy financial instrument that entitles the holder to be compensated or charged for congestion in the SPP Integrated Market between two settlement locations[56]. When transmission congestion occurs, KCPL incurs additional charges from SPP for moving energy from generation to load. KCPL, as a transmission owner, is allocated TCR's to hedge the actual transmission congestion charges incurred to serve its native load. A transmission owner in SPP is an owner of physical assets within a given service territory

TCRs may result in a source of revenue or a charge from SPP. Based on discussions with KCPL personnel and responses to Staff data requests, KCPL sells more power into SPP than it purchases from SPP, a situation commonly referred to as "long-in-the-market." In other words, in total, KCPL produces more electrical energy for the SPP market than it takes from this market. Consequently, TCRs are a source of revenue for KCPL for the period of March 1, 2014 through the update period December 31, 2014.

Staff annualized TCRs for the period March 1, 2014, the date the IM market began, through December 31, 2014, the update period in this case. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment Rev-14.4. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

[56] SPP Tariff 105.

I. Market to Market Sales

In SPP's Integrated Market, KCPL has the opportunity to purchase energy from SPP and subsequently sell energy to another energy market. KCPL monitors the price differences in each real time market and if it is determined that a transaction will be profitable, the purchase and subsequent sale is made.

Although the SPP Integrated Market began on March 1, 2014, KCPL did not begin energy market-to-market transactions until May 10, 2014. Staff annualized KCPL's market-to-market transactions for the period beginning May 10, 2014, through December 31, 2014, the update period in this case. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment Rev-14.3. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

J. Revenue Neutral Uplift

The revenue neutral uplift charges are imbalances between revenues and disbursements that are distributed by SPP to SPP market participants as either a charge or a credit. As a not-for-profit organization, SPP must remain revenue neutral. Consequently, SPP will charge or credit KCPL for the revenue neutral uplift charge. The charge consists of miscellaneous charges or credits that SPP has no other method of distributing to SPP market participants.

Staff annualized revenue neutral uplift charges for the period March 1, 2014, the date the Integrated Market began, through December 31, 2014, the update period in this case. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment Rev-14.2. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

K. Off-System Sales

1. FERC Account 447-Sales for Resale

FERC Account 447, Sales for Resale, includes three sources of revenue for KCPL:

- firm off-system sales;
- non-firm off-system sales; and
- FERC wholesale sales

2. Firm Off-System Sales

During the Test Year ended March 31, 2014, updated through December 31, 2014, KCPL contracted to sell firm off-system power to the following customers:

1. Independence Power & Light ("IP&L")
2. City of Chanute, Kansas ("Chanute"); and
3. City of Eudora, Kansas ("Eudora")
4. Kansas Municipal Energy Agency ("KMEA"); and

Under their respective contracts, these customers paid both a demand charge for the megawatt capacity commitment from KCPL and an energy charge for the cost of delivered energy. However, the firm contract with IP&L terminated in March 2014. In addition, KCPL has an agreement with GMO to sell a specified amount of capacity at GMO's option. As a result, Staff annualized KCPL's firm demand and energy sales based solely on the capacity contracts in effect with Chanute, Eudora and KMEA (plus the capacity sales option with GMO) as of the update period ended December 31, 2014.

Staff has reviewed KCPL's firm off-system sales levels and adjusted test year levels to reflect the levels for the 12-month update period ended December 31, 2014. Adjustments Rev-8.1 and Rev-9.1 reflect the adjustments to firm off-system sales levels.

Staff Expert/Witness: V. William Harris

3. Non-Firm Off-System Sales

For purposes of discussing revenue requirement calculations, non-firm off-system sales are sales of electricity made at times when a utility's generation output exceeds the load requirements of its native load customers (rate tariff customers) and firm sale customers. KCPL must first meet its firm sales loads and if it has excess electricity to sell it will make off-system sales. The difference between the revenue received for selling the excess generation, and the cost of the fuel used to produce the energy sold are referred to as Off-system sales margin ("OSSM"). Off-system sales are made at market-based rates. Off-system sales are made through KCPL's generation or through electricity purchased from other utilities. The aggregate off-system sales net margins are used in the revenue requirement calculation.

Since March 2014, KCPL has taken part in the SPP integrated market. KCPL offers its generating units for dispatch through the SPP, and the SPP dispatches KCPL and all other SPP generating owners' generation to meet the load requirements of the entire SPP region. For purposes of discussing revenue requirement calculations, once all firm commitments are met (native load), any excess generation is available to sell through the market on a non-firm basis—off-system sales. Staff adjustments Rev 11.1 and Rev 12.1 are reflected in Staff's Accounting Schedule 9.

4. Net Margin on Non-Firm OSS

The Commission has addressed off-system sales in each of KCPL's last rate cases. In this case, KCPL has included off-system sales as part of its fuel modeling analysis. Staff has also included generation and purchases for off-system sales in its fuel model.

KCPL and Staff each have produced a fuel run which incorporates many different inputs such as retail kWh sales, unit availabilities for power plant outages, fuel prices and purchased power prices. Each of these differences, result in different levels of retail sales, or net system input (NSI) and any corresponding off-system sales. There is an inverse relationship in the level of retail sales and off-system sales. The greater the retail sales, given the finite level of generation KCPL has and the limits of purchasing electricity, the less opportunities there are for off-system sales. Conversely, if there are fewer retail sales required of the system, generation and purchases are freed-up to allow for a greater amount of off-system sales.

As changes are made to retail sales in this case, a corresponding change to off-system sales will be necessary. Reducing retail sales will cause a need to examine the off-system sales levels, likely causing an increase to off-system sales.

Staff intends to work with KCPL to determine the appropriate level of off-system sales to include in the overall revenue requirement calculation. There likely will be changes to many of

the inputs that KCPL and Staff propose to be used in development of the fuel and purchased power costs once discussions among the parties occur. As changes to the inputs occur, those changes will cause further changes to the retail sales (net system input) and off-system sales.
Staff Expert/Witness: Cary G. Featherstone

5. FERC Wholesale Sales

FERC wholesale customers are municipalities that buy electricity under a firm power tariff regulated by the FERC. Since the wholesale customers are treated as if they were located in another jurisdiction, none of the revenues from these customers are included in the Missouri utility's regulated operations. Staff allocates to the Missouri utility the plant-in-service, accumulated depreciation reserves, revenues, fuel and purchased-power costs and maintenance costs required to serve Missouri customers using demand and energy allocation factors developed by Staff witness, Alan J. Bax. The FERC jurisdictional loads are not included in the demand and energy allocators developed for the Missouri jurisdiction.
Staff Expert/Witness: V. William Harris

L. Excess Off-System Sales Margin Regulatory Liability

Pursuant to KCPL's Regulatory Plan, KCPL agreed that off-system energy and capacity sales revenues, and related costs, will continue to be treated "above the line" for ratemaking purposes over the course of the Regulatory Plan. KCPL also agreed that it would not propose any adjustment that would remove any portion of its off-system sales from its revenue requirement determination in any rate case during the life of the Regulatory Plan.

In its first rate case after the Commission approved the Regulatory Plan, Case No. ER-2006-0314, the Commission determined that, in setting KCPL's rates, the amount included in KCPL's revenue requirement for off-system sales should be the 25th percentile of non-firm off-system sales margin as projected in that proceeding, that KCPL book all amounts above the 25th percentile as a regulatory liability, but no corresponding regulatory asset would be booked should sales fail to meet the 25th percentile. This Order established the 2006 rate case tracker for off-system sales. The Commission ordered a continuation of this method of accounting for off-system sales in each of KCPL's three subsequent general rate cases, Case Nos. ER-2007-0291, ER-2009-0089 and ER-2010-0355.

In the *Non-Unanimous Stipulation and Agreement* the Commission approved in Case No. ER-2009-0089, the parties agreed to the final dollar amount for the 2006 and 2007 rate case trackers. The parties also agreed to set the 2009 rate case tracker off-system sales baseline at $30,000,000:

> Off-System Sales ("OSS") Margins—Excess Over 25th Percentile for 2007 and 2008
>
> The Signatory Parties agree that the $1,082,974 (Missouri jurisdictional) excess of 2007 OSS margins over the amount included in rates in Case No. ER-2006-0314 and the $2,947,332 (Missouri jurisdictional) excess of 2008 OSS margins over the amount included in rates in Case No. ER-2007-0291, together with interest (Missouri jurisdictional), will be deferred in a regulatory liability account and amortized over ten years beginning with the date new rates become effective in this rate case, with one year's amortization included in cost of service in this case. The unamortized balance will not be included in rate base.
>
> * * *
>
> Off-System Sales Tracker
>
> KCP&L's OSS margins at the 25th percentile shall be set at $30 million, and shall be used for tracking purposes. Such tracker will reflect a pro-ration, on a monthly basis, of this amount for any partial years consistent with the percent of actual OSS realized in each month of 2008. All OSS margins will be tracked against the $30 million baseline. The Signatory Parties reserve the right to assert a position regarding the appropriate definition of OSS in the Company's next general rate case.

Page 141 of the Commission *Report and Order* in KCPL Case No. ER-2010-0355, issued April 12, 2011, states, "KCP&L's rates shall be set at the 40th percentile of non-firm off-system sales margin as projected by KCP&L, as listed in KCP&L witness Schnitzer's Direct Testimony. Margins above the 40th percentile shall be returned to ratepayers in a subsequent rate case or rate cases." KCPL did not realize any excess margins over the 40th percentile from the 2010 rate case and, thus, made no related adjustments to its regulatory liability.

Staff has calculated the amount of KCPL's amortization and interest related to this regulatory liability from the 2006, 2007 and 2009 rate cases and reflected the appropriate amount in Adjustment Rev-4.1.

Staff Expert/Witness: V. William Harris

M. SO^2 Emissions Allowances

1. Deferred Sales from SO^2 Emissions Allowances

Since KCPL receives more SO^2 emission allowances ("SO^2 allowances") from the U.S. Environmental Protection Agency ("EPA") than it requires for its own coal-burning operations, it may sell all or part of these surplus allowances. Under the FERC Uniform System of Accounts ("USOA"), proceeds from the sales of surplus SO^2 emissions allowances are recorded in FERC Account 254, the USOA regulatory liabilities account. For ratemaking purposes, amounts recorded as regulatory liabilities reduce a utility's rate base; i.e., the net amount in FERC Account 254, after any appropriate adjustments, is an offset to rate base.

Staff included in its direct case the balance of Account 254 on December 31, 2014 (the end of the update period in this case), as an offset to the rate base calculation found on Staff Accounting Schedule 2 filed with Staff's direct case. This approach is consistent with the treatment given this item in the last five KCPL rate cases: Case Nos. ER-2006-0314, ER-2007-0291, ER-2009-0089, ER-2010-0355 and ER-2012-0174. Staff has reflected the amortization associated with this regulatory liability in Adjustments E-29.1 and E-30.1. Treating these SO^2 emissions allowances in this manner acknowledges that, through rates, KCPL's customers have paid for KCPL's production facilities that create these SO^2 emissions allowances, which KCPL is able to sell to other entities for profit.

Staff Expert/Witness: V. William Harris

N. Miscellaneous Revenues

1. Late Payment Revenue (Forfeited Discount)

KCPL charges a late payment fee to customers who fail to pay bills in a timely manner. Staff annualized late payment fee revenues by using the ratio of late payment fees to Missouri total retail sales, both net of gross receipt taxes (GRT), from January 31, 2014 through December 31, 2014. This ratio was multiplied by the Staff annualized revenue resulting in an annualized level of late payment fees. This is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-15.2.

Staff Expert/Witness: Keith Majors

O. Other Revenue Accounts

Staff reviewed the amounts KCPL included in its cost of service calculation for "Other Revenues," which include rent from electric property, miscellaneous service revenues and temporary installation profit. Staff concluded the test year amounts for Other Revenues appeared to be reasonable and representative of an annualized level of revenue for each respective category and, therefore, do not require adjustment. However, Staff will apply its own allocation factors to those amounts that are common to other KCPL's operational jurisdictions. Staff will examine these revenue accounts again during its True-Up audit through May 31, 2015.

Staff Expert/Witness: Keith Majors

P. Removal of Gross Receipts Taxes from Test Year Revenues

The amounts received from customer payments and recorded as revenues during the test year include Gross Receipts Taxes (GRT). GRTs are imposed by a taxing authority for which KCPL is obligated to charge customers on their utility bills. After KCPL collects these taxes from its customers, it periodically remits these amounts to the appropriate taxing authority. In this regard, to accurately account for KCPL's actual test year retail revenues – it is necessary to remove GRT from the amounts recorded as revenues during the test year – while at the same time removing the corresponding remittances to the taxing authority as a charge to expenses. In effect, GRT will have no impact on KCPL's final revenue requirement amount. Staff's adjustments remove GRT from test year revenues and expenses and are reflected in Staff's Accounting Schedule 9, Rev-3.1, Rev-15.1 and E-254.1.

Staff Expert/Witness: Keith Majors

IX. Income Statement – Expenses

A. Fuel and Purchased Power Overview

KCPL has 4,493 megawatts of total generating capacity consisting of nuclear, coal-fired, natural gas, oil-fired generating units and wind generation. KCPL's generation capacity is made up of the following types of generation based on calendar year 2014 operating results:

Generation Capacity by Fuel Type	2014 Megawatts	Percentage of Generation Capacity by Fuel Type	2014 Percentage of MWHs Generated by Fuel Type
Coal	2,751 MWs	61.2%	81%
Nuclear	549 MWs	12.2%	16%
Natural Gas	772 MWs	17.2%	Less than 1%
Oil	375 MWs	8.4%	Less than 1%
Wind	46 MWs	1%	2%
Total	4,493 MWs	100%	100%

Source: 2014 Shareholder Report- pages 8 and 23.

While KCPL's coal-fired generating units make up 61% of its total generating fleet, those units produce 81% of total system load requirements. Nuclear generating capacity makes up 12% of total KCPL capacity, but it produces 16% of total generation. Natural gas capacity makes up 17% of total capacity this fuel type makes up less than 1% of KCPL's total generation based on 2014 actual megawatt hours of generation.

continued on next page

2012 - 2014 actual generation based on MMBTU's are:

Generation	2014 Actual MMBTU	%	2013 Actual MMBTU	%	2012 Actual MMBTU	%
Coal	** __________ **	79.21%	** ________ **	82.50%	** ________ **	80.3%
Nuclear	** ________ **	19.81%	** ________ **	16.36%	** ________ **	18.2%
Natural Gas	** ________ **	.73%	** ________ **	.92%	** ________ **	1.4%
Oil	** ____ **	.25%	** ____ **	.22%	** ____ **	.2%
Total	** ________ **	100%	** ________ **	100%	** ________ **	100%

Based on the actual 2014 generation by fuel type, coal and nuclear make up 99% of total generation with oil and natural gas making up less than 1% of generation.

B. Fuel and Purchased Power Expense

Staff determined KCPL's variable fuel and purchased power expense to be ** ______________ ** for the test year, 12-months ending March 31, 2014 updated through December 31, 2014.

Staff uses the Plexos production cost model to perform an hour-by-hour chronological simulation of a utility's generation and power purchases. Staff uses this model to determine annual variable cost of fuel and net purchased power energy costs and fuel consumption necessary to economically meet a utility's load within the operating constraints of the utility's resources used to meet that load. These amounts are supplied to Auditing Department Staff who use this input in the annualization of fuel expense.

Staff used market prices in its fuel model dispatch to simulate KCPL's operations in the SPP's integrated marketplace (IM). The price for energy in the IM dictates the amount of energy KCPL sells in the IM, so Staff's fuel run dispatches KCPL's generation to match KCPL's load, which simulates how the SPP would dispatch if that generation was being dispatched into the SPP IM based on prices set by the SPP's regional load requirements.

The model operates in a chronological fashion, meeting each hour's energy demand before moving to the next hour. It will schedule generating units to dispatch in a least cost manner based upon fuel cost and purchased power cost while taking into account generation unit operation constraints and firm purchased power contract requirements. This model closely simulates the way a utility should dispatch its generating units and purchase power to meet the net system load in a least cost manner.

Inputs calculated by the Staff are: fuel prices, firm purchased power contract specifications, spot market purchased power prices and availability, hourly net system input (NSI), and unit planned and forced outages. The Staff relied on KCPL's responses to data requests, and data KCPL supplied to comply with 4 CSR 240-3.190, for the characteristics of each generating unit; characteristics such as: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, and fixed operating and maintenance expense. Information from KCPL's firm wholesale loads and firm purchased power contracts, such as hourly energy available and prices, are also inputs to the model.

Staff Expert/Witness: Shawn E. Lange

1. Capacity Contract Prices and Energy

Capacity contracts are contracts between two utilities for a specific amount of capacity and a maximum amount of hourly energy. Two contracts are for energy from units which can be dispatched by KCPL. Those two units are included in the production cost model as dispatchable units.

Staff Expert/Witness: Shawn E. Lange

2. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In particular, forced outages are unplanned and can happen at any time. In order to capture this variability, the KCPL generating unit outages were normalized by averaging the six years ending December 2014 of actual values taken from responses to data requests, and data KCPL supplied to comply with 4 CSR 240-3.190, and KCPL's response to Staff Data Request No. 0045.

In January 2012, Wolf Creek experienced a forced outage that lasted approximately 73 days. KCPL and Westar, two owners of Wolf Creek, have filed suit[57] against ABB Inc. for work that may have caused that outage. Staff has removed that outage from the forced outage calculation.

Staff Expert/Witness: Shawn E. Lange

3. Fixed Costs

Fuel and purchased power costs that do not vary directly with fuel burned were not included in Staff's fuel model, but were determined separately. The non-variable fuel costs that were determined separately and included in fuel expense are typically referred to as "fuel adders." These types of costs include non-wage fuel handling, dust suppressant and freeze proofing coal for transportation from the mines to power plants. The non-variable purchased power costs not included in Staff's fuel model are commonly referred to as "capacity charges" or "demand charges" and are annualized separately from purchased power energy costs.

Staff Expert/Witness: Karen Lyons

4. Fixed Adders

As described above, fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in Staff's fuel model. The costs of fuel adders are determined separately and are added to the level of fuel expense determined by the model to determine overall fuel expense. Costs added to coal expense include unit train lease payments and unit train rail car maintenance costs. Fuel adders for natural gas include transportation charges and hedging costs. A significant percentage of natural gas transportation charges is fixed and under contract.

For natural gas fixed transportation costs and additives such as limestone and ammonia, Staff used the actual expenses for the 12-months ending December 31, 2014. Staff's adjustments are identified on Schedule 9 of Staff's Accounting Schedules, Adjustments E-13.1, E-13.2, and E-93.1. Staff will re-examine these expenses at the time of Staff's true-up, and update any costs necessary.

Staff Expert/Witness: Karen Lyons

[57] Case number 1316-CV09206.

5. <u>Purchased Power – Energy</u>

Staff Adjustment E-109.1 annualizes purchased power energy charges based on Staff's fuel model results. These purchased power energy charges represent the energy KCPL purchases on the spot market and through contracts to meet the system load requirements of its retail electric customers. Staff witness Erin L. Maloney is responsible for determining the appropriate amount of purchased power and the proper price for this power, and provided the results to Mr. Shawn E. Lange of the same department, who was responsible for operating the fuel model and for providing various inputs to this model.

Staff Expert/Witness: Karen Lyons

6. <u>Purchased Power – Capacity Charges</u>

Capacity charges, commonly referred to as "demand charges," represent fixed amounts that KCPL pays for the "right" to purchase power or is paid by another entity for the "right" to purchase power from KCPL. In the case of purchased power, the selling entity reserves generating capacity for KCPL to purchase when the electricity is needed under terms of the purchased power agreements. KCPL contracts this power with various entities and pays a fixed component for the reserve capacity and an energy component for any energy consumed. Generally, there is also an amount for operational and maintenance costs charged for the usage of energy. The fixed component is paid by KCPL as a demand charge, generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase the reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

The demand charges paid to KCPL by other generating entities, giving those entities the "right" to purchased power from KCPL, are known as capacity sales. The demand charges for capacity sales are addressed in the revenue portion of this Cost of Service Report by Staff witness V. William Harris.

Staff Adjustment E-110.1 annualizes purchased power demand charges based on existing capacity contracts currently in effect. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Staff reviewed each of these contracts, and determined the appropriate costs per megawatt hour and the amount of megawatts purchased. Staff included the costs reflected in KCPL's capacity agreements that were in effect on December 31, 2014.

Staff Expert/Witness: Karen Lyons

7. Variable Costs

a. Fuel Prices

Staff computed coal fuel expense using coal prices and quantities as of January 1, 2015. For all other fuel expenses, Staff computed fuel expense using prices and quantities actually incurred by KCPL as of December 31, 2014. Staff included fuel prices for nuclear, coal, natural gas, and oil, including transportation charges in fuel accounts 501 (coal), 518 (nuclear), and 547 (natural gas).

Staff Expert/Witness: Karen Lyons

b. Coal Prices

Staff determined coal prices by generation facility based on a review and analysis of KCPL's coal purchase (supply) and coal transportation (freight) contracts. Staff's recommended coal prices reflect KCPL's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect on January 1, 2015.

Staff Expert/Witness: Karen Lyons

c. Natural Gas Prices

As an input to its production cost model, Staff used twelve (12) monthly natural gas prices calculated using 12-month weighted averages of KCPL's actual commodity cost of natural gas through the end of the known and measurable period of December 31, 2014. KCPL's natural gas fixed transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Karen Lyons

d. Nuclear Fuel Prices

KCPL owns 47% of Wolf Creek. KCPL's 47% ownership interest in Wolf Creek entitles it to 547 megawatts of the plant's capacity. In making its nuclear fuel price adjustment, Staff relied upon KCPL's monthly Report 25 - the Fuel Report. Staff noted that monthly nuclear fuel price, decreased significantly in May 2014. Based on discussions with KCPL personnel, the decrease in price is attributable to the discontinuance of the nuclear waste disposal fee in May 2014, an event that is separately discussed in this report. Staff's proposed nuclear fuel price is based on the most current fuel price as of December 31, 2014.

Staff Expert/Witness: Karen Lyons

e. Oil Prices

Staff used the actual cost KCPL paid for its most recent fuel oil purchases to determine variable fuel oil expense. KCPL burns fuel oil mainly as a start-up fuel for the coal-fired generating units or, in some instances, for flame stabilization. Oil is a primary fuel source at KCPL's Northeast units, which see very limited run time. As a result, KCPL purchases fuel oil infrequently. Historically, the limited number of purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An accurate historical analysis of fuel oil prices is also not possible because KCPL does not make purchases during the majority of the year. For its direct filed case, KCPL purchased oil in 2014 and therefore Staff recommends KCPL's most recent fuel oil purchase prices as of December 31, 2014, to input into the fuel model for determining KCPL's variable fuel and purchased power expense on a going forward basis.

Staff Expert/Witness: Karen Lyons

8. <u>Purchased Power Prices</u>

The Staff analyzed hourly Southwest Power Pool (SPP) Integrated Market (IM) power prices beginning with the start of the IM on March 11, 2014, through the end of November 2014. Staff developed hourly average prices weighted by the actual day-ahead generation sales made at the Kansas City Power & Light locational marginal price nodes during each hour in this period. The IM was only active for part of the test year; therefore the resulting 8,760 hourly prices developed as input to the production cost model were adjusted to reflect a full year of IM operation. Staff will continue to review purchased power prices through the true-up period, and will update the inputs as necessary.

Staff Expert/Witness: Erin L. Maloney

9. <u>Department of Energy Nuclear Waste Fund Fees Accounting Order</u>

Until May 16, 2014, the Department of Energy (DOE) was charging a fee of 1 (one) "mil" (1/10 of one cent, or 1/1000 of one dollar) per kWh of electricity produced at Wolf Creek to the owners of Wolf Creek for the storage of spent nuclear fuel and materials used in the production of electricity at Wolf Creek. This regulatory fee had been assessed since Wolf Creek started operating in September 1985. KCPL's customers indirectly have been paying this fee continuously through rates for over 29 years.

The Nuclear Waste Policy Act of 1982 authorized the DOE to enter into contracts for the collection and disposal of spent nuclear fuel and high level waste. On October 10, 1984, the owners of Wolf Creek entered into a Standard Contract with the DOE which required them to pay fees into the Nuclear Waste Fund, in exchange for which the DOE would begin to dispose of the spent nuclear fuel and high level waste associated with Wolf Creek not later than January 31, 1998. The principle site for this disposal was the Yucca Mountain Nuclear Waste Repository in the state of Nevada.

The DOE failed to meet its 1998 obligation and has not accepted any nuclear materials for permanent storage. The fee was challenged in the courts and in late 2013, the United States Court of Appeals issued its decision in *National Association of Regulatory Utility Commissioners v. United States Department of Energy*, where it ordered that the Secretary of the DOE submit to the United States Congress a proposal to change the fee to $0. The DOE reduced the fee to the current level of $0 (zero dollars) effective May 16, 2014. Despite being reflected in utility rates which customers continue to pay, KCPL is no longer incurring this fee resulting in a cost savings to it.

On October 9, 2014, Staff filed its *Petition For Accounting Order,* requesting the Commission to order KCPL to record to a regulatory liability, the amount in KCPL's rates for Nuclear Waste Fund fees. The case was docketed as Case No. EU-2015-0094. On January 19, 2015, Staff and KCPL filed a *Joint Motion to Consolidate Cases,* which stated that the two cases involve related questions of law and fact, and requested that the Commission consolidate the two cases. The cases were consolidated by the Commission effective January 30, 2015.

The current level in rates for DOE fees was established in KCPL's last general rate increase case, Case No. ER-2012-0174. That case used a test year ending March 31, 2012, and a true-up period ending August 31, 2012. The DOE fees were included in the nuclear fuel price Staff used in its fuel dispatch modeling. Staff included fuel costs for Wolf Creek annual generation of 4,485,176 megawatt hours (MWh), which translates to $4,485,176 (one dollar per MWh) in DOE fees. Nuclear fuel expense is charged to Account 518, Nuclear Fuel Expense. KCPL separately tracks the DOE spent nuclear fuel fees in a sub account it established—FERC Account 518.201 Nuclear Fuel – Disposal Cost. Staff's energy allocation factor in that case, which it used to allocate certain costs between Missouri, Kansas, and Federal Energy Regulatory Commission (FERC) jurisdictions for Account 518, was 57.12%, resulting in $2,561,932 being included annually in the Missouri jurisdictional cost of service of KCPL for the DOE spent nuclear fuel fees. In each of KCPL's rate cases going back to its 1985 rate case where the Commission first authorized the inclusion of Wolf Creek in rate base, KCPL's rates have included a level of costs relating to Wolf Creek's operations, including the DOE spent nuclear fuel fees.

In Case No. EU-2015-0094, Staff requested the Commission order KCPL to establish a regulatory liability subaccount in FERC Account 254 – Other Regulatory Liabilities to capture the Missouri jurisdictional portion of the DOE fees being paid in Missouri customer rates for disposition in a future KCPL general rate proceeding. The amount that would be included in that subaccount would be calculated from the date the fee went to zero—May 16, 2014—through the date new rates take effect that reflect the reduction in the fee. The amount to be booked into that account is $7,019 per day ($2,561,932 ÷ 365 days) starting May 16, 2014.

Prior to May 16, 2014 KCPL recorded a liability to DOE for the amount of the Nuclear Waste Fund fees which was paid with cash collections from its customers KCPL recorded as revenues. In this current 2015 KCPL rate case, Staff requests the Commission order KCPL to record a liability for those fees paid in rates in the same manner as a regulatory asset which utilities periodically request through an issuance of an AAO (accounting authority order). KCPL currently has several subaccounts in Account 254. Staff recommends the Commission order this liability to be established in the next available code block (e.g., "Account 254###") with the description, "KCPL - MO DOE Fees Regulatory Liability." Staff recommends the amount recorded to the liability account should be the amount collected in rates from KCPL's Missouri customers from May 16, 2014, through the effective date of rates in this case – expected to be September 29, 2015. The total accumulated amount through the effective date of rates in this case is $3,516,515 through September 28, 2015. For Staff's direct filing, the amount has been calculated through May 31, 2014 – the true-up date, at a total accumulation of $2,674,236. In this case, Staff recommends the accumulated amount for DOE fees no longer paid by KCPL but being collected in existing rates should be returned to customers over five years as a reduction to fuel expense.

Staff believes the Court order declaring that the DOE fee be reduced to zero from the 1 mil per kWh assessment qualifies as an "extraordinary event." Generally, the Commission in prior cases has stated that the standards for granting the authority to, or in this case, ordering, a utility to defer costs incurred outside of a test year as a regulatory asset are 1) that the costs pertain to an event that is extraordinary, unusual and unique, and not recurring; and 2) that the costs associated with the event are material. Typically, these standards are applied to a utility request for an AAO outside of the rate case process.

Staff considers the abrupt termination of the payment of the DOE fees after KCPL incurred these costs for nearly 30 years to be unusual, unique, and non-recurring, and consequently extraordinary. First, the expense KCPL incurred in the past for the DOE fees could be considered a form of a tax that is levied for a specific public policy purpose; in this case, to fund disposal activities related to spent nuclear fuel and high level waste storage for the protection of the public health. If amounts recovered in rates by KCPL related to DOE funding can no longer be dedicated to that purpose, it is equitable to use the current over-recovery of this item for some alternative purpose useful to KCPL's customers rather than simply allow KCPL to book increased earnings as a result.

Second, the DOE payments ceased due to a court order, and the action of halting the payments was not in any way within KCPL's control, making the impact of the court order an unearned financial "windfall" for KCPL.

Third, the DOE fees were mandated by the federal government for the specific and sole purpose of the long-term storage of radioactive waste from the use of nuclear fuel and related materials. The United States government had, and has, the sole responsibility and obligation to take ultimate possession of nuclear waste for storage and disposal. To date, the DOE has failed to do so. The regulatory commissioners throughout the country were instrumental in bringing the case before the courts as members of the National Association of Regulatory Commissioners (NARUC). A federal court determined that utility owners of nuclear power plants were no longer under obligation to make further payments to the DOE at this time as DOE did not meet its obligations of disposing nuclear waste.

The cessation of the DOE fees is different than other expenses that can and do vary between rate cases. For example, in 2013 KCPL reduced its workforce after the completion of the 2012 case by a net of ** ___ ** employees—rates in that case went into effect January 2013. The annual salaries, wages, and benefits (with a 60% payroll benefits adder) related to these employees are an annual savings to KCPL of ** __________ **, approximately ** __________ ** Missouri jurisdictional. To KCPL's benefit, Staff included costs associated with these employees in KCPL's cost of service in the 2012 Rate Case, and KCPL retained the earnings benefits resulting from those reductions and will continue to retain that benefit until rates are changed as result of this case through what is known as "regulatory lag." As payroll and benefits are part of the many normal expenses and revenues that form the entire picture of a utility's cost of service, Staff does not believe it would be appropriate to capture these expense reductions in a regulatory liability account, unlike in the more unique circumstances of the DOE fees.

Therefore, because the cessation of the DOE fees is extraordinary, Staff recommends the amount of the Missouri jurisdictional savings be accumulated into a regulatory liability and returned to customers as a reduction to nuclear fuel expense over five years.

Staff has identified the dollar amount of the accumulated DOE fees as of the true-up date – May 31, 2014 and reflected a $1/5^{th}$ amount to reduce nuclear fuel costs determined in this case.

Staff Adjustment E-55.1 reflects this amortization in its determination of KCPL's cost of service.

Staff Expert/Witness: Keith Majors

10. Normalization of Hourly Net System Input

Hourly net system input (NSI) is the hourly electric supply necessary to meet the hourly energy demands of both the utility's customers and is net of (i.e., does not include) station use, which is the electricity requirement of the utility's generating plants.

Due to the presence of significant air conditioning and electric space heating in KCPL's service territory, the magnitude and shape of KCPL's net system input is directly related to daily temperatures. To normalize NSI Staff used actual and normal daily temperatures provided by

Staff witness Seoung Joun Won, Ph.D. in its analysis. The actual daily temperatures for the modified year period differed from normal daily temperatures. Therefore, to reflect normal weather, daily peak and average net system loads are each adjusted independently, but using the same methodology.

Daily average load is the summation of the hourly load for the day divided by twenty-four hours and the daily peak is the maximum hourly load for the day. Staff uses separate regression models to estimate both a base component, which is allowed to fluctuate across time, and a weather sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. Independent regression models are necessary because daily average loads respond differently to weather than peak loads. The model's regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. The adjustments for each day are added respectively to the actual average and to the peak loads of each day. The starting point for allocating the weather-normalized daily peak and average loads to the hours is the actual hourly loads for the year being normalized. A unitized load curve is calculated for each day as a function of the actual peak and average loads for that day. Staff uses the corresponding weather-normalized daily peak and average loads, along with the unitized load curves, to calculate weather-normalized hourly loads for each hour of the year.

This process includes many checks and balances, which are included in the spreadsheets that are used by Staff. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads."[58]

After weather-normalizing and annualizing usage for KCPL's Missouri jurisdictional retail customer classes is completed, weather-normalized wholesale usage as well as any non-Missouri jurisdictional usage is added to produce an annual sum of the hourly net system loads that equals the adjusted test year usage, plus losses, and is consistent with Staff's Missouri jurisdictional normalized revenues.

Staff applies a factor to each hour of the weather-normalized loads to produce an annual sum of the hourly net-system loads that equals the usage, plus losses, consistent with normalized

[58] Weather Normalization of Electric Loads, Part A: Hourly Net System Loads" (November 28, 1990), written by Dr. Michael Proctor, Manager of the Economic Analysis Department.

revenues. Once completed, the hourly normalized system loads were used in developing fuel and purchased power expense. Staff witness Alan J. Bax also used the annual requirement of the net system load in developing the Staff's jurisdictional energy allocator.

Staff Experts/Witnesses: Shawn E. Lange and Seoung Joun Won, Ph.D.

11. Losses

System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) between KCPL's generating sources and its customers' meters. In addition, small, fractional amounts of energy that is either diverted (stolen) or unmetered (unmetered usage) are included as system energy losses.

The basis for calculating system energy losses is that Net System Input (NSI) is equal to the sum of Retail Sales, Wholesale Sales, and System Energy Losses. This can be expressed mathematically as:

NSI = Retail Sales + Wholesale Sales + System Energy Losses

NSI, Retail Sales and Wholesale Sales are known quantities; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – (Retail Sales + Wholesale Sales)

The system energy loss percentage is the ratio of system energy losses to NSI multiplied by 100:

System Energy Loss Percentage = (System Energy Losses ÷ NSI) X 100

NSI is also equal to the sum of the Company's net generation and net interchange. Net interchange is the difference between off-system purchases and off-system sales. Net generation is the total energy output of each generating plant minus the energy consumed internally to enable the production of electricity at each plant. The output of each generating plant is monitored and metered continuously. The net of off-system purchases and off system sales (Net Interchange) is monitored as well.

Staff calculated the loss percentage of KCPL's system, for the twelve months ending March 2014, as 5.90% of NSI. Staff witness Seoung Joun Won, Ph.D. used this loss percentage in the development of hourly loads used in Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

12. Surface Transportation Board Reparation Amortization

On October 12, 2005, KCPL filed a rate complaint case with the Surface Transportation Board ("STB") against Union Pacific Railroad ("UPRR") alleging UPRR's charges to transport coal from Wyoming's Powder River Basin (PRB) to KCPL's Montrose plant in Missouri were excessive.

On May 15, 2008, the STB ruled in favor of KCPL and ordered UPRR to reduce its rates to KCPL and pay KCPL reparations for prior overcharges. The STB estimated the value of the rate reductions and reparations to be $30 million.

During the period between the STB rate complaint case and the final decision, KCPL filed two general rate cases before this Commission, Case No. ER-2006-0314 and Case No. ER-2007-0291. In Case No. ER-2006-0314, Staff and KCPL, by agreement, treated KCPL's actual STB litigation costs as a regulatory asset amortized to expense over five (5) years beginning in January 2007. Staff and KCPL also agreed that proceeds from the complaint were first to be applied as an offset to any existing balance of the STB case costs in the regulatory asset, with the remainder being applied to offset fuel costs as determined in future proceedings. The Commission in its Report and Order in that case observed that the agreement between Staff and KCPL "appears just and reasonable". In KCPL's next Missouri rate case, Case No. ER-2007-0291, Staff and KCPL continued this same treatment of deferring and amortizing the Missouri jurisdictional portion of KCPL's STB litigation costs.

In the KCPL rate case subsequent to the 2008 STB ruling, Case No. ER-2009-0089, KCPL calculated a rate recovery for STB costs and reparations from UPRR in excess of its STB costs of $1.38 million. KCPL distributed this excess to the three entities that it claimed contributed funds to the cost of prosecuting the STB case. These entities were the City of Independence (through its capacity contract with KCPL), Missouri regulated customers and Kansas regulated customers. In addition, KCPL allocated a portion of the excess to its wholesale customers who apparently did not contribute funds to the cost of the STB complaint case.

KCPL updated this calculation in the 2009 rate case based on corrected information and included additional reparations received from UPRR. Staff used the calculation methodology in KCPL's work paper, with two corrections.

First, KCPL failed to include all of the funds included in Case No. ER-2007-0291 rates in the total amount of the STB costs contributed by Missouri ratepayers. Staff added $143,945, the amount KCPL collected in rates from January 2008 through September 2008. This amount was earmarked for STB case expense recovery, but was excluded by KCPL in its calculation. Second, since KCPL's wholesale customers did not contribute to the STB rate case recovery, Staff reallocated the amounts credited to Missouri and Kansas regulated customers by using the appropriate Missouri-Kansas allocation percentage.

The Non-Unanimous Stipulation and Agreement in Case No. ER-2009-0089, approved by Commission Order effective June 23, 2009, states in part, "the Missouri jurisdictional excess of STB litigation proceeds over un-recovered STB litigation costs of $1,017,593 will be deferred in a regulatory liability account and amortized over ten years beginning with the date new rates become effective in this case ... The unamortized balance will not be included in rate base." Rates became effective September 1, 2009. The test year amount on KCPL's books reflects the appropriate amortization level; therefore, no adjustment was necessary for this case.

Staff Expert/Witness: V. William Harris

C. Payroll, Payroll Related Benefits including 401k Benefit Costs

1. Payroll Costs

Staff has examined the payroll costs of KCPL and recommends distributing its annualized payroll costs using ratios derived from the existing payroll distribution of KCPL's recorded payroll costs during the test year. Staff recommends annualizing KCPL's payroll expense using actual employee levels as of the end of the update period, December 31, 2014 plus the directly assigned Wolf Creek payroll. KCPL employees perform all services for Great Plains, KCPL and GMO, (including both rate districts, MPS and L&P) and certain portions of KCPL's non-regulated enterprises. Since KCPL employees perform all services for Great Plains and its subsidiaries, an allocation of KCPL's payroll costs is necessary to assign the proper amounts of payroll costs to each of the Great Plains entities, including KCPL. Staff has reviewed KCPL's allocation of actual assigned payroll costs by month for each of these entities and allocated annualized payroll based on this allocation.

Staff annualized KCPL's payroll costs in this case using actual employee levels as of December 31, 2014, the most current historical information available as of the end of the update period. Each individual employee's current hourly wage or salary was annualized to compute an annual total payroll cost for KCPL. Staff's annualized payroll includes base wages, overtime, differential and premium pay, paid to KCPL's union employees based on union contracts as well as an annualized level of payroll for the Wolf Creek generating facility. Wolf Creek payroll is discussed further below.

After KCPL payroll was annualized, payroll costs linked to employees of the KCPL's jointly-owned generation facilities were allocated among the joint owners based on their ownership shares. The following table shows KCPL's ownership share of jointly owned plant facilities:

Power Plant	KCPL's Ownership Share	Other Ownership Shares
La Cygne 1	50%	50%
La Cygne 2	50%	50%
Iatan 1	70%	30%
Iatan 2	55%	45%

After the removal of payroll that is allocated to joint-owners, it is necessary to allocate the remaining payroll costs among KCPL and its affiliates. To allocate the remaining payroll costs, Staff utilized KCPL's historical allocation ratios for KCPL and GMO's MPS and L&P rate districts, with the exception of overtime, which is booked directly to the affiliate for which the cost was incurred. Staff concluded that the historical charged amounts of payroll expense represent the best allocation of payroll between KCPL, GMO, and non-regulated operations.

After the annualized payroll was allocated to Great Plains, KPCL and GMO, the KCPL-only payroll costs also were further allocated between O&M expense (operation and maintenance expense), and non-O&M expense—the capitalized amount. Typically, non-O&M expense relates to construction or other capital projects along with non-utility functions of the company. The amounts that are included in the revenue requirement calculations for KCPL are the O&M levels of total payroll expense after the application of an O&M expense ratio. Staff used a three-year average of historical O&M expense ratios to calculate the proper level of payroll costs to charge to KCPL's O&M expense.

The Wolf Creek generating station is managed by a separate entity, Wolf Creek Nuclear Operating Company ("WCNOC"), which charges Wolf Creek payroll directly to KCPL for its share (based on 47% KCPL plant ownership) of the total Wolf Creek payroll expenses. Since Wolf Creek payroll is directly assigned to KCPL by WCNOC and KCPL is the only Great Plains entity that has an ownership share of Wolf Creek, allocation of Wolf Creek's costs between the

Great Plains entities is unnecessary. For Wolf Creek base payroll, Staff included the last known annual amount. For Wolf Creek overtime, no discernable trend was found, so Staff included an average amount of the calendar years 2013 and 2014. Staff did not include 2012 in its average because the 2012 amount of overtime was unusually high.

After the allocation of total KCPL payroll costs to joint-owners, affiliates, and O&M, Staff distributed the remaining payroll by FERC account based upon the actual payroll distribution among those accounts at the end of the test year, March 31, 2014. The following are the adjustments Staff made to allocate the annualized payroll to each of these FERC accounts:

Adjustments E-4.1, E-7.1, E-18.1, E-21.1, E-35.1, E-38.1, E-41.1, E-44.2, E-47.1, E-54.1, E-58.1, E-59.1, E-60.1, E-61.1, E-61.2, E-73.1, E-74.1, E-75.1, E-75.2, E-79.1, E-80.1, E-91.1, E-96.1, E-97.1, E-98.1, E-102.1, E-103.1, E-104.1, E-105.1, E-112.1, E-113.1, E-118.1, E-119.1, E-120.1, E-121.1, E-124.1, E-130.1, E-131.1, E-132.1, E-133.1, E-134.1, E-140.1, E-141.1, E-142.1, E-143.1, E-144.1, E-145.1, E-146.1, E-147.1, E-148.1, E-149.1, E-152.1, E-153.1, E-154.1, E-155.1, E-156.1, E-157.1, E-158.1, E-159.1, E-160.1, E-164.1, E-165.1, E-166.1, E-170.1, E-173.1, E-174.1, E-179.1, E-181.1, E-186.1, E-188.1, E-192.1, E-195.1, E-198.1, E-202.1, E-203.1, E-204.1, E-213.1, E-214.1, E-218.1, E-220.1, E-222.1, E-229.1

Staff Expert/Witness: Matthew R. Young

2. <u>Payroll Related Benefits</u>

KCPL incurs costs for a variety of payroll-related benefits such as 401k matching and employee insurance premium contributions. For all payroll benefits except the 401k matching costs, Staff included the most recent historical cost level, as of December 31, 2014 in its determination of KCPL's cost of service. Because it is additional employee compensation, Staff allocated payroll-related benefits to the owners of jointly-owned generating stations using the same method Staff used to allocate the associated base payroll of those employees. That method is described in the payroll section of this report.

Staff's annualized KCPL 401k costs were calculated based upon an average of actual 401k percentage match applied to KCPL's share of total annualized payroll. The average percentage match was calculated by dividing the percentage of KCPL's actual non-stock (cash) 401k match by the actual 401k eligible payroll expense in three separate pay periods and averaging those ratios. Staff Adjustments E-205.2 and E-205.3 to Staff's Income Statement (EMS Schedule 9) reflect Staff's normalized payroll benefits, based on KCPL's payroll costs as of December 31, 2014.

Staff Expert/Witness: Matthew R. Young

3. <u>Payroll Taxes</u>

Payroll taxes were annualized by applying current payroll tax rates to each employee's annualized level of payroll. Staff used the 12 months ended December 31, 2014, actual cost for Wolf Creek payroll taxes. For developing Staff's annualized payroll taxes, Staff used the same method that it used to allocate KCPL's payroll. Staff Adjustment E-250.1 to Staff's Income Statement (EMS Schedule 9) reflects the annualized payroll taxes based on payroll costs as of December 31, 2014.

Staff Expert/Witness: Matthew R. Young

4. <u>True-up of Payroll Costs</u>

Staff will update the total payroll, payroll-related benefits and payroll taxes based on actual historical information through May 31, 2015, for the true-up in this case. The same methodology used to annualize payroll as of December 31, 2014 will be used for the true-up.

Staff Expert/Witness: Matthew R. Young

5. <u>FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset</u>

Staff and KCPL entered into a Stipulation and Agreement in KCPL's 2012 rate case (Case No. ER-2012-0174) titled, *"Non-Unanimous Stipulation and Agreement As To Certain Issues"* ("Agreement"). Among other items, this Agreement addressed the ratemaking treatment for annual pension costs under Financial Accounting Standard (FAS) No. 87 (FAS 87), and pension settlement and curtailment accounting under Financial Accounting Standard No. 88 (FAS 88).

The names of the Financial Accounting Standards have recently changed. The Financial Accounting Standards Board's Accounting Standards Codification project was launched in 2009 and became the single source of authoritative nongovernmental U.S. Generally Accepted

Accounting Principles (GAAP) (other than guidance issued by the Securities and Exchange Commission). The new Codification Topic 715 covers all of the following FAS statements under its various subtopics:

- FAS 87 and FAS 88, Employers' Accounting for Pensions;
- FAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans; and
- FAS 106, Employers' Accounting for Post Retirement Benefits other than Pensions.

While the individual FAS statements have been combined into Codification Topic 715, for the purposes of this Report, Staff will use the original FAS statement numbers, such as FAS 87, FAS 88, FAS 106 and FAS 158, as needed.

The Agreement in Case No. ER-2012-0174 reaffirmed the prior provisions regarding these matters reached in KCPL's Regulatory Plan and clarified the accounting for pension cost allocated to KCPL's joint partners in the Iatan and La Cygne generating stations. It also addressed the ratemaking treatment for a curtailment or settlement recognized under FAS 88.

There are two amounts in KCPL's rate base relating to pensions resulting from agreements regarding regulatory assets reached in the various agreements reached in Case Nos. EO-2005-0329, ER-2006-0314, ER-2007-0291, ER-2009-0089, ER-2010-0355, and ER-2012-0174:

1) A Prepaid Pension Asset – The prepaid pension asset represents the unrecovered balance of negative pension cost flowed back to ratepayers in prior years.
2) A FAS 87 Regulatory Asset – Under the terms of the Stipulation and Agreements referenced above, the difference between FAS 87 reflected in rates and KCPL's actual cost recorded in its financial statements is tracked and recorded as either a regulatory asset or liability, and is then amortized over five years in the next rate case. KCPL's rate base includes a regulatory asset as of December 31, 2014.

Staff's recommended annualized level of KCPL pension expense is based on information provided by KCPL's actuarial firm, Towers Watson, which KCPL in turn provided to Staff in response to Staff Data Request No. 0171. Staff's calculation of KCPL's pension expense was made in accordance with the methodology described in the Agreement reached in Case No. ER-2012-0174.

Based on the language of the Agreement in Case No. ER-2012-0174, Staff is proposing cost of service recovery of $16.7 million (KCPL share) in FAS 88 charges through a five-year amortization increase to pension expense.

The FAS 88 charge is related to the impact on pension expense of employees being removed from KCPL's pension plans and the impact of paying lump sum pension distributions to these employees in the alternative. While the FAS 88 charge is an increase to cost of service, the ongoing level of pension expense should be lower due to the removal of these employees' costs from the pension plan.

Ongoing pension expense and the rate base portion of the pension tracker mechanism are included in Staff Adjustments E-204.2, E-204.3, E-204.4, E-204.5, and E-204.6 to the Income Statement – Schedule 9, and Rate Base – Schedule 2.

Staff Expert/Witness: Keith Majors

6. <u>FAS 106 – Other Postretirement Benefit Costs (OPEBs) and OPEB Tracker Regulatory Liability</u>

Other Postretirement Benefit Costs (OPEBs) are those costs KCPL incurs to provide certain benefits to KCPL retirees. The primary benefit is medical insurance, but they also include life, dental and vision insurance benefits. Historically OPEB costs have been calculated by KCPL's actuaries under the terms of Financial Accounting Standard 106 (FAS 106).

FAS 106 is the Financial Accounting Standards Board (FASB) approved accrual accounting method used for financial statement recognition of annual OPEB costs. The accounting of the cost of postretirement benefits is not based on the actual dollars KCPL pays for OPEBs to its retirees currently, but FAS 106 is accrual-based in that it attempts to recognize the financial effects of noncash transactions and events as they occur. These noncash transactions and events are primarily current benefits earned by employees before retirement, but not paid until after retirement, as well as the interest cost arising from the passage of time until those benefits are paid).

KCPL does not fund its share of Wolf Creek OPEB expense based on FAS 106 calculations. KCPL funds Wolf Creek OPEB based on the actual amount of benefits paid, not the FAS 106 calculated accrual. This method is generally referred to as "pay-as-you-go".

Staff's OPEB adjustment to KCPL Account 926, Employee Benefits annualizes the level of OPEB expense determined by KCPL's actuaries using the FAS 106 accounting method, with the exception of KCPL's portion of Wolf Creek OPEB expense, calculated as the 12 months ending December 31, 2014 actual payments.

Beginning May 4, 2011, KCPL initiated a new tracker for OPEB costs which the Commission authorized in Case No. ER-2010-0355. What is tracked are the differences between the current ongoing level of OPEB expense funded by KCPL in an external trust and the dollar amount of OPEB expense reflected in rates in each case. The unamortized balance of this tracker will be amortized over five years in each successive rate case, and either be added to or subtracted from the level of OPEB expense as determined by KCPL's actuaries. As with other rate base prepaid pension and other pension assets, it is anticipated that the OPEB tracker liability will be updated through the May 31, 2015 true-up period.

Ongoing OPEB expense and the rate base portion of the OPEB tracker mechanism are included in Staff Adjustments E-205.5, E-205.6, and E-205.7 to the Income Statement – Schedule 9, and Rate Base – Schedule 2.

Staff Expert/Witness: Keith Majors

7. <u>Supplemental Executive Retirement Plan (SERP) Expense</u>

Included in Staff's revenue requirement recommendation is an annualized level of actual monthly-recurring SERP payments KCPL made to its former executives and other highly compensated former employees. SERPs are non-qualified retirement plans for officers and other highly-compensated employees that provide pension benefits that these individuals would have received under other company retirement plans, except for compensation and benefit limits imposed by the Internal Revenue Service (IRS). These supplemental pension benefits paid to retired former officers and executives are in addition to the cost of pension benefits KCPL pays under its all-employee FAS 87 pension plan. SERP pension benefits generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. SERP benefits are not externally funded by KCPL, and the amounts Staff included in is cost of service of KCPL are based upon actual cash SERP payouts to covered employees.

SERP payments consist of monthly annuity payments and periodic lump-sum distributions. Lump-sum payments can be significant and are often difficult to predict. As opposed to including a normalized amount of actual lump-sum payments, KCPL used a conversion factor of 14.3 to convert prior lump-sum payments to an amount that approximates the equivalent annuity payments to the qualifying employees as if that lump-sum payment option were not elected. Staff utilized this factor for the calculation of a normalized level of converted lump-sum payments.

Staff recommends that a three year average of monthly annuity payments, and a three year average of converted lump-sum payments, be used in this rate case to determine allowable SERP expense in rates. This approach is reflected in Staff's revenue requirement recommendation as Adjustment E-204.8 to Account 926, Employee Benefits.

Staff Expert/Witness: Keith Majors

8. <u>Short Term Annual Incentive Compensation</u>

KCPL has two short-term annual incentive compensation plans for executive and management employees. These plans are designed to grant cash awards of various amounts calculated based upon designated annual metrics. Incentive compensation accrues over a calendar year and is paid out in the first quarter of the following calendar year. The two incentive compensation plans are 1) the Value-Link Plan, reserved for management-level KCPL employees; and 2) the Annual Executive Incentive Plan, reserved for senior management-level KCPL employees.

The incentive plans all have benchmarks that identify targets that KCPL employees are expected to achieve before any cash payouts are awarded. These targets are established each year of the incentive plan and communicated to the employees early enough so that the employees have sufficient opportunity to reasonably achieve the benchmarks.

Staff removed test year payouts for the Annual Executive Incentive Plan and 58.1% of the Value-Link Plan from the test year incentive compensation expense, as those payouts were awarded based upon attainment of certain financial metrics, i.e., Earnings per Share (EPS). The Commission has historically disallowed the awarding of incentive compensation tied to the utility achieving certain corporate financial goals on the basis that these goals provide no tangible benefit to Missouri ratepayers. *See* specifically *Re KCPL*, Case Nos. ER-2006-0314, 15 Mo.P.S.C.3d 138, 171-72 (2006) and *Re KCPL*, ER-2007-0291, pp. 49-51 (2007).

The remaining incentive compensation amounts were then allocated to the affiliates of KCPL and also allocated to capital. Staff Adjustments E-4.3, E-91.2, E-102.3, E-113.2, E-118.2, E-140.2, E-148.5, E-164.2, E-165.3, E-166.2, E-181.2, E-192.3, and E-204.7 reflect KCPL's jurisdictional expense portion of incentive compensation.

Staff Expert/Witness: Matthew R. Young

D. Maintenance Normalization Adjustments

Maintenance expense is the cost of maintenance chargeable to the various operating expenses and clearing accounts. It includes labor, materials, overheads, and any other expenses incurred in maintaining the Company's assets - including power plants, transmission and distribution network of the electric system, and the general plant. Specific types of maintenance work tied to specific classes of plant are listed in functional maintenance expense accounts in the FERC USOA for the various types of utilities. Maintenance expense normally consists of the costs of the following activities:

- Direct field supervision of maintenance;
- Inspecting, testing and reporting on condition of plant, specifically to determine the need for repairs and replacements;
- Work performed with the intent to prevent failure, restore serviceability or maintain the expected life of the plant;
- Testing for, locating, and clearing trouble;
- Installing, maintaining, and removing temporary facilities to prevent interruptions; and
- Replacing or adding minor items of plant, which do not constitute a retirement unit.

Staff analyzed maintenance costs from 1999 through December 31, 2014, by functional area for production, transmission, distribution, and general plant by FERC account. Staff separated maintenance between labor and non-labor costs. Since labor costs are separately addressed as a component in the cost of service analysis, labor costs were removed from Staff's analysis in order to perform a review of non-labor maintenance costs only.

Several steps were taken to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by the Staff was to compare functional averages, which included using a two (2)-year average through a seven (7)-year average to determine if there were fluctuations with each functional area. Staff also analyzed Production maintenance excluding Iatan Unit 2 production maintenance. The purpose of excluding Iatan Unit 2 production maintenance costs is to identify if production maintenance fluctuated absent these costs. After isolating Iatan Unit 2 production maintenance Staff determined production maintenance remained relatively consistent for the calendar years 2012 through 2014 and decided to adjust test year levels to the known and measurable update levels to reflect the most current data available. Staff will adjust maintenance again to reflect the levels incurred during the 12-months ending May 31, 2015 during the true-up in this case. Each of the costs by year and averages for maintenance were also compared to the Test Year, 12-month period ended March 31, 2014 and the known and measurable update period ended December 31, 2014. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs.

Staff performs a separate analysis for Iatan Unit 2 production maintenance. A discussion for Iatan Unit 2 production maintenance is located under the heading *Iatan Unit 2 O&M Expenses* in this report.

Staff's results are presented in the following table:

Results of Staff's Non-Labor Maintenance Analysis	
Steam Production Maintenance	12-Month Update Ended December 31, 2014
Nuclear Production Maintenance	12-Month Update Ended December 31, 2014
Other Production Maintenance	12-Month Update Ended December 31, 2014
Transmission Maintenance	12-Month Update Ended December 31, 2014
Distribution Maintenance	12-Month Update Ended December 31, 2014
General Maintenance	12-Month Update Ended December 31, 2014

As identified in the table above, Staff made a decision to use the 12-month known and measurable update period ended December 31, 2014 account balances to represent future maintenance costs for Production, Nuclear, Other Production and General Maintenance for purposes of its direct case filing. Staff used the 12-month update period to reflect a level of normalized maintenance for these costs based on actual information provided by KCPL for a period of several years. This historical information was analyzed to determine the proper level of maintenance which should be included in KCPL's cost of service in this case.

For Wolf Creek, there are two types of O&M costs – O&M for general plant, and O&M relating to the refueling outages that occur every 18 months. Staff performs a separate analysis for nuclear refueling outages. A discussion of the O&M expenses related to the Wolf Creek refueling is located under the heading *Wolf Creek Nuclear Refueling Outage* in this report. The adjustments for Wolf Creek non-refueling Production Maintenance are E-73.2, E-74.2, E-75.3, E-75.4, E-79.2 and E-80.2. The adjustments for Steam Production Maintenance are E-35.2, E-38.2, E-41.2, E-44.1 and E-47.2. The adjustments for Other Production Maintenance are E-102.2, E-103.2, E-104.2 and E-105.2. The adjustments for Transmission Maintenance are E-129.1, E-130.2, E-131.2, E-132.2, E-133.2 and E-134.2. The adjustments for Distribution Maintenance are E-152.2, E-153.2, E-154.2, E-155.2, E-156.2, E-157.2, E-158.2, E-159.2 and E-160.2. The Adjustment for General Maintenance is E-229.3.

Staff Expert/Witness: V. William Harris

1. <u>Wolf Creek Nuclear Refueling Outage</u>

Staff included an annualized level of refueling costs for refueling outage #19, completed in the spring of 2013, and an amortization of refueling outage #18 as calculated and agreed to in the prior rate case, Case No. ER-2012-0174. Staff reviewed information provided by KCPL for the last seven nuclear refueling outages. While refueling costs have increased over the last five refuelings, the only significant increase was from refueling #17 to refueling #18. Staff determined the age of the plant and unplanned equipment issues led to the increased costs experienced with outage #18. KCPL responded to Data Request No. 0147.2[59] as follows:

**

[59] Case No. ER-2012-0174.

NP

**

The increase in refueling costs has since leveled off, as the increase from refueling #18 to refueling #19 was only 4.22%. In this case, refueling costs booked in the test year reflect costs associated with refueling #19. The costs associated with Wolf Creek refueling outage #19 are deferred and amortized over an 18-month period. The monthly deferral is then annualized to adjust the test year cost. Adjustments E-67.1 and E-76.1 reflect the annualized refueling costs.

In addition to the annualized refueling costs for refueling outage #19, Staff reflected the remaining refueling amortizations established in the prior two rate cases – refueling #18 in Case No. ER-2012-0174 and refueling #16 in Case No. ER-2009-0089. The deferral of the amortized refueling #18 amount began February 2013 and will end January 2018. The test year amount recorded on KCPL's books reflects the appropriate amortization level; therefore, no adjustment was necessary for this refueling. The deferral of the amortized refueling #16 amount began September 2009 and ended September 2014. Since the refueling #16 amortization has ended, Staff removed the test year expense related to this refueling. Adjustments E-68.1 and E-77.1 reflect the removal of refueling #16 amortization expense from the cost of service in this case.

KCPL's current rates reflect the refueling #16 amortization expense and will continue to do so until the effective date of rates in this proceeding. As a result, KCPL is realizing an over recovery of this expense. Adjustments E-69.1 and E-78.1 remove the over recovery of this expense from October 2014 through the May 2015 true-up period by offsetting the remaining 28 months (October 2015 through January 2018) of the refueling #18 amortization. Staff reserves the right to readjust this over recovery during true-up to reflect the over recovery through the September 2015 date the new rates will become effective.

Staff Expert/Witness: V. William Harris

a. Nuclear Decommissioning

In its *Order Approving Stipulation And Agreement* in Case No. EO-2012-0068, the Commission ordered the following:

NP

. . .

> 3) Kansas City Power & Light Company's retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264.
>
> 4) The current decommissioning costs for Wolf Creek are included in Kansas City Power & Light Company's current Missouri cost of service and are reflected in its current Missouri retail rates for ratemaking purposes.[60]

In its *Order Approving Stipulation And Agreement* in Case No. EO-2015-0056, the Commission ordered the following:

. . .

> 4) Kansas City Power & Light Company's retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264.
>
> 5) Kansas City Power & Light Company is authorized to continue to record and preserve Wolf Creek asset retirement obligation costs, as agreed by the Commission Staff, the Office of the Public Counsel, and KCP&L and authorized by the Commission in Case No. EU-2004-0294.
>
> 6) This order shall become effective on January 21, 2015.[61]

After reviewing KCPL's work papers, Staff found the test year reflected the amount ordered by the Commission and, therefore, no adjustment was necessary.

Staff Expert/Witness: V. William Harris

2. <u>Wolf Creek Mid-Cycle Outage</u>

KCPL's test year included a planned mid-cycle outage at the Wolf Creek generating station. The mid-cycle outage began March 8, 2014 and was completed on May 13, 2014. Adjustments E-59.2, E-61.3, E-73.3, E-74.3, E-75.5, E-79.3 and E-80.3 reflect an annualized five-year amortization of the costs related to this mid-cycle outage.

Staff Expert/Witness: V. William Harris

[60] File No. EO-2012-0068, *Order Approving Stipulation and Agreement*, p. 3.

[61] File No. EO-2015-0056, *Order Approving Stipulation and Agreement*, p. 3.

3. Iatan Unit 2 O&M Expenses

In Case No. ER-2010-0355, Staff recommended a tracker for Iatan Unit 2 O&M expense, so the actual cost of the O&M expense related to Iatan Unit 2 would be recovered through rates for both the ratepayer and KCPL in future rate cases. Since Iatan Unit 2 was placed in service on August 26, 2010, and KCPL's operational experience with Iatan Unit 2 was non-existent at the time of Case No. ER-2010-0355, an O&M tracker was suggested to protect both KCPL and its customers from including projected costs in rates that would in all likelihood vary from the actual costs associated with Iatan Unit 2's O&M expense. KCPL and other signatory parties agreed through a Non-Unanimous Stipulation and Agreement in Case No. ER-2010-0355 to establish a tracker for Iatan Unit 2 costs and on April 12, 2011, the Commission approved the use of a tracker for these costs.

In Case No. ER-2012-0174, a three (3)-year amortization of the actual Iatan Unit 2 costs that exceeded the base rates established in Case No. ER-2010-0355 was included in KCPL's cost of service. In addition, a new base level was established for the Iatan Unit 2 tracker and also included in KCPL's cost of service on a going-forward basis. At the time of the 2012 rate case, KCPL only had limited operating experience with the two-year old plant.

In this case, Staff is proposing the recovery of the excess costs over the base amount established in Case No. ER-2012-0174. Staff is again proposing a three (3)-year amortization of the excess costs over the base amount. Adjustments reflecting one-third of the total costs are reflected in Staff's Accounting Schedule 9, in Adjustments E-5.1, E-16.1, E-19.1, E-22.1, E-26.1, E-36.1, E-39.1, E-42.1, E-45.1, E-48.1 and E-196.1.

As previously mentioned, Iatan Unit 2 was placed in service on August 26, 2010. At the end of the true-up period in this case, May 31, 2015, the plant will have operated for nearly five (5) years. As a result Staff is recommending that this tracker be discontinued since a level of historical O&M expense has been established for Iatan Unit 2 and common operations. During subsequent audits and examinations, Staff should treat Iatan Unit 2 and common costs as a normal component of O&M expense in the cost of service just like it does with all the other power plants operated by KCPL.

As previously discussed, a three (3) year amortization of the excess Iatan Unit 2 O&M expense over the base amount established in Case No ER-2010-0355 was included in KCPL's cost of service in Case No. ER-2012-0174. The effective date of rates in Case No.

ER-2012-0174 was January 26, 2013. The amortization period for these costs will end on January 26, 2016. Given the limited experience with operating and maintaining Iatan Unit 2, when it was placed in service, a maintenance tracker was established to protect KCPL and its customers. The tracker is not intended to allow KCPL to over recover the actual maintenance expenses incurred for Iatan Unit 2 but to recover the actual reasonable and prudent costs. It was not intended that the O&M tracker for Iatan Unit 2 allow for KCPL to profit from its existence. Staff recommends the Commission require KCPL to track any over recovery associated with any amortization established as a result of the Iatan Unit 2 tracker and any over recovery will be addressed in the next KCPL rate case.

Staff Expert/Witness: V. William Harris

4. IT Roadmap O&M

KCPL included an adjustment for ongoing operations and maintenance associated with support information technology systems and infrastructure. KCPL identified the following four information technology areas as pertaining to its adjustment:

- IT Roadmap Applications and Infrastructure
- Operations Maintenance (Including software and systems maintenance)
- Cyber Security
- Ongoing O&M

Staff analyzed KCPL's actual non labor information technology maintenance costs from the period of 2009 through 2014, including the Critical Infrastructure Protection program. The Critical Infrastructure Protection program is not included in KCPL's proposed adjustment. Upon review of the costs, Staff found that KCPL books this type of expense to several FERC accounts that Staff historically includes in its maintenance normalization. These FERC accounts include 591, 598 and 935. To prevent duplication of Staff's adjustments for the costs booked in these accounts, Staff eliminated the costs in its review of KCPL's information technology expense. Staff's recommendation for KCPL's maintenance expense is addressed by Staff witness V. William Harris in the "Maintenance Normalization Adjustments" section of this report.

Staff found the costs for information technology including the Critical Infrastructure Protection program showed an upward trend through December 31, 2014. Consequently, Staff annualized the costs as of December 31, 2014. Staff's adjustment is identified on Schedule 9 of

Staff's Accounting Schedules, Adjustment E-195.4 and E-195.5. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

E. Other Non-Labor Adjustments

1. <u>Bad Debt Expense</u>

Staff's recommended treatment of bad debt expense is to calculate the ratio of KCPL's net write-offs to annualized retail revenue to determine an appropriate level of bad debt expense. Bad debt expense is the portion of retail revenues KCPL is unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over to a third party collection agency for recovery. If KCPL is subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those amounts collected reduce the actual write-offs. This results in the net write-off which is used to determine the annualized level of bad debt expense.

Staff calculated the annualized bad debt expense by examining the ratio between billed revenues, net of gross receipt taxes for the twelve months period ending June 30, 2014, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending December 31, 2014. From this information a bad debt ratio was derived, which was then applied to Staff's annualized, weather normalized level of retail revenues to obtain the annualized level of bad debt expense. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with KCPL's position on how bad debt write-offs are accounted.

KCPL asserts that it takes approximately six months for a customer's unpaid bill to be written off after the customer receives service. Staff's adjustment for bad debt expense adjusts the test year results to reflect a level of bad debt expense that is consistent with Staff's annualized level of retail revenue. Adjustment E-168.1 in Staff's Accounting Schedule reflects an annualized level of bad debt expense.

Staff Expert/Witness: Keith Majors

2. Advertising Expense

In forming its recommendation of the allowable level of advertising expense, Staff relied on the principles the Commission followed as a result of the 1986 Kansas City Power & Light rate case, beginning with the KCPL's 2006 rate case, Case No. ER-2006-0314. In Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) (KCPL), the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission are:

1. General: advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;
4. Institutional: advertising used to improve the company's public image;
5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements because a utility's revenue requirement should: 1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement (Report and Order in KCPL Case No. EO-85-185, 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)). In response to data requests, KCPL provided a list of all costs associated with advertising and a brief description of those costs. The purpose of Staff's review of KCPL's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in KCPL's cost of service. For example, all direct and indirect costs associated with safety advertising were included as well as other costs necessary for KCPL to communicate with its customers on utility matters (i.e., general advertising). Staff removed test year expenses incurred by KCPL for cost classified as "Other Advertising", but will reevaluate this adjustment once the data request response requesting an explanation for these expenses has been received. Staff focused on advertising campaigns, not just individual advertisements, which is consistent with the Commission's decision relied on in its Order for AmerenUE in Case No. ER-2008-0318. Adjustments E-178.1, E-179.2, E-186.2 and E-195.6.

Staff Expert/Witness: Joel A. Molina

3. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations that KCPL charged to its utility accounts during the test year. Staff removed costs in which it considers the expenses to be of a personal nature to a KCPL employee or of no direct benefit to the ratepayers and, thus, should not be included in a utility's cost of service. The adjustment was made to Account 930.2. Adjustment E-222.2

KCPL accounted for donations made to charitable organizations as a below-the-line expense amount—expenses that are not included in the determination of the revenue requirement. Staff examined, but did not find any other donations that should be removed from the cost of service. While important for KCPL to be a good corporate organization, donations made to these organizations do not provide any direct benefit to its customers in the provision of electric service. Also, charging donations made by regulated utilities to customers would make those customers involuntary contributors. Finally, KCPL and its owners, not its customers, receive a benefit of being a good corporate citizen through the enhancement of the Company's image. Customers receive no benefit from this enhanced KCPL corporate image. For these reasons, utility rates typically do not include cost recovery of charitable donations.

Staff Expert/Witness: Joel A. Molina

4. Miscellaneous Test Year Adjustments

In its direct filing, KCPL included Adjustment CS-11 which includes several categories of miscellaneous adjustments totaling a reduction of $5,516,272 to its test year cost of service. For the December 31, 2014 update period, KCPL updated CS-11 to include a total reduction of $5,633,714. There are several categories within the total adjustment:

A. Remove director and officer long-term incentive compensation that KCPL proposes to charge below the line

B. Reclassify the costs of promotional advertising, lobbying, and non-recoverable dues to below the line

C. Miscellaneous coding corrections that occurred after the test year's March 31, 2014 cut-off

D. Remove the costs Great Plains officer expenses (This adjustment E-195.9 is discussed further by Staff witness Charles R. Hyneman)

Staff has reviewed and reflected these adjustments to the test year cost of service for KCPL as Staff Adjustments E-21.3, E-132.4, E-148.5, E-174.3, E-192.2, E-195.8, E-199.2, E-213.3, E-222.5, E-222.6, E-222.7.

Staff Expert/Witness: Matthew R. Young

5. Legal Fee Reimbursements

In its direct case, KCPL included Adjustment CS-115 to amortize two legal fee reimbursements that were amortized over three years, one in Case No. ER-2010-0355 and the other in ER-2012-0174. The Missouri jurisdictional balances of these reimbursements are treated as regulatory liabilities on KCPL's books and records.

Legal Fee Reimbursement One was received in December 2008 and amortized as a reduction to cost of service over three years beginning May 4, 2011 – the effective date of rates in Case No. ER-2010-0355. This regulatory liability was fully amortized as of April 2014.

Legal Fee Reimbursement Two was received in November 2010 and amortized as a reduction to cost of service over three years beginning January 27, 2013 – the effective date of rates in Case No. ER-2012-0174. This regulatory liability has a balance of $362,978 as of December 31, 2014.

The amortization of Legal Fee Reimbursement One fully eliminated its liability as of April 2014. As of the projected true-up in this case, the balance of Legal Fee Reimbursement Two will be fully eliminated by the amortization of Legal Fee Reimbursement One. Therefore, Staff recommends both amortizations should be removed from the cost of service as Adjustments E-200.1 and E-200.2.

Staff Expert/Witness: Keith Majors

6. Debit/Credit Card Acceptance Program

In February 2007, KCPL implemented a Credit/Debit Card payment program designed to offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their accounts electronically. KCPL has implemented the program through two service agreements. The first agreement is with Paymentech, LLC ("Paymentech"), a subsidiary of JPMorgan Chase Bank, N.A. and is for credit and debit card payments. The second agreement is with Speedpay, Inc. ("Speedpay"), a subsidiary of E Commerce Group Products, Inc. (a subsidiary of The

Western Union Company) and is for ATM Card and debit card payments made over the telephone. Paymentech and Speedpay act as third party facilitators for the processing of payments to KCPL. Payment options available to customers through the program include the Interactive Voice Response System ("IVR") and/or by registering on KCPL's website. Payment through the website offers the following two options: one time payments, or what the Company terms the "recurring card payment option," which is available through registration on its website. The cost for providing this service is absorbed by KCPL and later built into rates; therefore, customers who use this payment option are not charged any direct transaction fees. Since the introduction of the program in February 2007, customer participation has been gradually increasing. Participation is projected to increase into the future as more customers become aware of the program. As customer participation increases, the per unit transaction cost to KCPL for providing the debit/credit payment service will decline.

Staff included in its cost of service an annualized amount associated with the credit and debit card program based upon the total card level and per unit transaction cost as of the twelve months ended December 31, 2014, to represent an ongoing level of costs (Adjustment E-167.1). Staff will review these costs through the true-up period, May 31, 2015 and make any necessary adjustments.

Staff Expert/Witness: V. William Harris

7. Accounts Receivable Bank Fees

KCPL sells its accounts receivable to Kansas City Power & Light Receivables Company ("KCREC"), an affiliated entity. This program increases immediate cash flow to KCPL and provides access to funds through lines of credit. As a result of the immediate cash flow and the need to no longer attempt to collect on its accounts receivable, KCPL reduces the collection lag associated with its CWC requirement. Ratepayers may benefit from the program because cash was generated by the sale of receivables instead of from the ratepayers. The effect of the selling of accounts receivable is that KCPL receives monies faster, shortening the overall revenue lag and reducing KCPL's revenue requirement. It is the entity purchasing the accounts receivable from KCPL that has to wait for the customers to pay over a normal period of time based on the Commission's billing rules. KCPL has to pay The Bank of Tokyo-Mitsubishi UFJ, Ltd. ("BTM) fees associated with the selling of the accounts receivable. As long as the fees KCPL pays to accelerate its cash recovery through the sale of its receivables is less than the revenue requirement decrease from the shorter collection lag, there is a likelihood that the sales of accounts receivable provides a customer benefit. In addition to the revenue requirement impact of KCPL's sales of its accounts receivable, the Staff is also reviewing whether or not the process and procedures developed by KCPL to sell its accounts receivable are in compliance with the Commission's Affiliate Transaction Rule. Please see the section in this report regarding KCPL's Affiliate Transactions.

KCPL sells its accounts receivables as follows:

- KCPL sells its electric receivables daily at a discount and on a non-recourse basis to Kansas City Power & Light Receivables Company ("KCREC"), a wholly-owned subsidiary of KCP&L.
- KCREC sells an undivided interest in the receivables to Victory. Receivables Corporation ("Victory"), a wholly-owned subsidiary of the Bank of Tokyo Mitsubishi.
- Victory issues commercial paper to fund the purchase of the receivables from KCREC.
- KCREC uses the cash it receives from Victory to partially pay KCPL for the receivables.
- KCREC gives a promissory note to KCPL for the difference between the partial payment and the total discounted purchase price.
- KCREC pays Victory interest, program fees and a commitment fee.

KCREC pays KCPL interest on the promissory note.

The adjustment for bank fees relates to the cost of the sale of its accounts receivable. Staff included the test year level of bank fees paid by KCPL to KCREC as Adjustment E-170.2 on Accounting Schedule 9. Adjustment E-170.3 reflects the difference between the test year level and Staff's annualized level of bank fees. Staff will review these costs through the true-up period, May 31, 2015 and make any necessary adjustments.

Staff Expert/Witness: V. William Harris

8. <u>La Cygne Regulatory Asset – Obsolete Inventory</u>

As a result of environmental equipment upgrades that will be placed in service at its La Cygne plant during 2015, KCPL is proposing to remove from rate base certain spare parts that are expected to become obsolete. KCPL is further proposing that this write-off of spare parts be amortized over a five-year period once the environmental equipment is placed into service. KCPL has removed these spare parts from rate base and included an annualized amount of amortization expense in its cost of service for this rate case filing.

At this time, Staff has also removed these spare parts from rate base and included an annualized amount of amortization expense in its cost of service for the direct filing (Adjustment E-41.3). As this expected inventory obsolescence is on-going and has not yet been replaced by new inventory at the time of this direct filing, Staff will continue to follow its progression throughout this case and will discuss this issue in-depth in its true-up filing. Staff would expect KCPL to remove from its adjustment any spare parts that can be considered "used and useful" at other KCPL plant facilities. Similarly, Staff would expect KCPL to offset the obsolete inventory adjustment with any residual or scrap value it realizes upon the sale or other disposition of the spare parts. Staff recommends the Commission allow KCPL to amortize, over a five-year period, the obsolete inventory levels determined at the end of the true-up period and track any over recovery associated with the amortization in order for such over recovery to be addressed for future treatment in subsequent rate proceedings.

Staff Expert/Witness: V. William Harris

9. Lease Expense

Lease costs are those costs incurred by KCPL for the leasing of its corporate headquarters. Staff examined these costs for the test year ended March 31, 2014 and update period through December 31, 2014. KCPL moved its corporate headquarters to One Kansas City Place, 1200 Main Street, Kansas City, MO during the fourth quarter of 2009. In December 2014, KCPL stopped using and leasing the 15^{th} floor of One Kansas City Place.

Staff recognized the monthly base rent for the headquarters, less rent attributable to the 15^{th} floor, and multiplied that by 12 months to reflect an annualized rent amount. In addition to the lease rent amount, the Company has to pay other costs for customer and employee parking, as well as an additional rent portion in the agreement for additional space when needed. KCPL currently rents five classifications of parking spaces: Visitor, Reserved, High Profile Vehicles, Director and Unreserved. To calculate an annualized amount for parking, Staff took the number of spaces provided in each category, except for visitor parking which is based upon Company estimates, and multiplied the number of spaces by the monthly rate, then further multiplied that total by 12 months to derive an annual value. Also, Staff used the adjustments of the Company to remove amounts that were associated with other standard parking accounts (such as employee-subsidized parking), so as to avoid double-counting this expense. Once the portions of the lease expense are totaled (base rent, parking, and additional rent) those amounts are then allocated between KCPL, GMO, and Great Plains. Staff has reflected the appropriate amounts for KCPL in Adjustments E-148.2, E-195.2, E-198.2, E-223.2, E-223.3 and E-229.2.

When KCPL relocated to its current location, it was allowed 270 days (9 months) of rent-free time, called an abatement period. In the 2010 rate case, KCPL agreed to establish a regulatory liability for costs that weren't incurred during the abatement period. These costs are being amortized and returned to rate payers over a five-year period that will end on May 31, 2016. Adjustment E-223.1 reflects the difference between Staff's annualized abatement amortization and the abatement amortization recorded on KCPL's test-year books.

Staff Expert/Witness: V. William Harris

10. Insurance Expense

Staff's recommended treatment of Insurance Expense is to treat prepaid insurance as an asset to be included in rate base and amortized ratably over the life of the insurance policy by annualizing the level of insurance expense and allocating an appropriate portion of the expense to KCPL's cost of service. Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events.

Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability associated with unanticipated losses for property assets and personal injury from accidents. Certain forms of insurance reduce ratepayer's exposure to risk. Premiums for insurance are normally pre-paid by utilities; i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect. These insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense ratably over the life of the period the insurance is in force. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense included in rates. Staff witness Joel A. Molina discusses the rate base treatment for prepayments in the Rate Base section of Staff's Cost of Service Report.

During the audit, Staff reviewed KCPL's insurance policies for the following forms of insurance:

- Crime
- Fiduciary Liability
- Directors and Officers
- General Liability/Umbrella
- Excess Directors & Officers
- Excess Liability
- Excess fiduciary
- Workman's Compensation
- Excess Workman's Compensation
- Property
- Labor Management Trust Fiduciary
- Auto Liability
- Bonds

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined and allocated between KCPL and its affiliates, including GMO. KCPL will renew its property insurance policies in May 2015 and as part of its True-Up audit, Staff will review these policies and recommend any necessary adjustments. The same methodology used to annualize Insurance Expense as of December 31, 2014 will be used to annualize Insurance Expense for May 31, 2015. The annualized levels for KCPL's portion of the insurance costs are reflected in Adjustments E-202.2 and E-203.2.

Staff Expert/Witness: Matthew R. Young

11. <u>Injuries and Damages</u>

Staff's recommended treatment of injuries and damages is to normalize KCPL's costs associated with injuries and damages, using a three-year average of actual cash payments made by KCPL and paid to individuals who had an injury and/or claim. Injuries and damages relate to insurance claims that are not covered by insurance policies and usually consist of claims associated with general liability, worker's compensation, and auto liability. As of the date of this report, Staff is continuing its audit of injuries and damages claims for prudency.

Staff analyzed ten years of data and determined a three-year average, including the period of 2012 through 2014, using the actual cash payments to normalize KCPL's costs associated with injuries and damages. The actual cash payments are those paid to individuals by KCPL who had an injury and claim. Based upon Staff's review of prior years' cash payments for claims against KCPL, Staff determined that use of a four-year average was the most appropriate rate allowance for this item based on the widely fluctuating levels of cash payments over time. This normalization of known and measurable changes of the actual cash payments over a multi-year period is consistent with KCPL's method to normalize injuries and damages in this rate case.

Adjustment E-203.3 reflects a normalized level of costs for injuries and damages.

Staff Expert/Witness: Matthew R. Young

12. Property Tax Expense

Staff's recommended treatment of Property Tax Expense is to annualize property tax expenses based upon property in-service on January 1, 2015, by multiplying that property amount by Staff's property tax ratio derived from historical tax payments. Staff adjusted test year property tax expense in order to include in rates the annualized level of 2015 property taxes.

Each year KCPL is billed by each of the local and state taxing authorities that have jurisdiction over KCPL's property. Tax bills for the year are based (assessed) on the property KCPL owns exclusively on January 1 of that calendar year. The property taxes assessed on the property owned as of January 1 of each year are typically not due to the various taxing authorities until December 31 of that same year. The exception is the property taxes assessed in the state of Kansas, where one-half of the year's property taxes are not due until late in the first quarter of the following year. The test year used in this case is the 12-month period ended March 31, 2014, updated through December 31, 2014. Since the update period in this case is December 31, 2014, Staff determined the annualized property taxes based on the property KCPL had in-service on January 1, 2015. Staff applied a property tax ratio based on actual 2014 property tax payments divided by January 1, 2014 taxable plant. In effect, the 2014 tax payments for property taxes develops a relationship to the tax amounts charged to expense to the assessed property—which is always based on the first day of the year. This ratio of property taxes applied to the January 1, 2015, assessed value of the plant provides the amount of property taxes expected to be due at the end of the year in 2015. Because the test year in this case ended March 31, 2014, property tax expenses for 2014 were annualized as of the January 1, 2015 date. The result of this calculation is what Staff expects KCPL's property tax cost to be for 2015. Both Staff and KCPL typically calculate this value by applying the tax rate paid for the previous year to the property owned at the start of the current year.

For the current rate case, Staff obtained from KCPL the total amount of taxable property KCPL owned on January 1, 2015, and then multiplied it by the 2014 property tax ratio, the most current information available. The 2014 property tax ratio is calculated by dividing the total actual amount of property tax paid by KCPL in 2014 by the total cost of the taxable property owned on January 1, 2014. Since the actual property taxes paid in 2014 was based on the assessments of the January 1, 2014 property, this ratio applied to the January 1, 2015 plant estimates the amount of property taxes that will be due at the end of 2015. The estimated 2015 property tax was then increased by KCPL's 2015 contractual payments in lieu of taxes ("PILOTs") applicable to non-taxable property.

Staff recommends this method of calculation as providing the best available information, since it relies on the actual January 1, 2015 balance of KCPL's property, and uses the most recent, known tax rate (2014), without attempting to estimate, or project any change in the rate of taxation for 2015 that is not known as of the update period December 31, 2014 and will not be known as of the May 31, 2015 true-up date.

Staff's approach is consistent with that taken previously and received several favorable rulings from the Commission in prior cases, most recently in KCPL 2006 rate case. In its *Report and Order* issued in Case No. ER-2006-0314 the Commission stated the following:

> Staff recommends that the Commission calculate property tax expense by multiplying the January 1, 2006 plant-in-service balance by the ratio of the January 1, 2005 plant-in-service balance to the amount of property taxes paid in 2005. KCPL wants the property tax cost of service updated to include 2006 assessments and levies. The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff.

Adjustment E-251.1 reflects Staff's annualized property taxes.

Staff Expert/Witness: Matthew R. Young

13. Rate Case Expense

Rate case expense is the sum of the costs a utility incurs in preparing and filing a rate case. In the instant case, KCPL has incurred expenses in conjunction with legal counsel, regulatory consulting and outside consultants. Staff recommends including 50% of prudently incurred rate case expense, recovered over three (3) years in KCPL's revenue requirement used for setting rates in this case, offset by the annual amounts resulting from the amortization of rate case expenses KCPL incurred under its Regulatory Plan.

a. Background

Generally, Staff divides rate case expense over the period of time it estimates will pass before the utility's next rate case, and includes an annual amount in the utility's revenue requirement. Typically, this cost is not "amortized" for ratemaking purposes, and the utility's recovery of this expense in rates is not tracked against its actual rate case expense for consideration of over or under recovery.

However, because KCPL's Regulatory Plan contemplated four rate case filings over less than four years, Staff did not oppose the "defer and amortize" or "vintage accounting" approach that KCPL requested in each of the Regulatory Plan rate cases—Case Nos. ER-2006-0314 ("2006 Rate Case"), ER-2007-0291 ("2007 Rate Case"), ER-2009-0089 ("2009 Rate Case") and ER-2010-0355 ("2010 Rate Case"). For the remaining rate case expenses for each of these cases, as adjusted, Staff used a "defer and amortize" approach to calculate the associated revenue requirement to be included in the following rate case. Under this special defer and amortize approach to rate case expense, KCPL deferred the rate case expenses for each rate case as a separate vintage deferral and amortized each of those vintage deferrals over a multi-year period. The rate case expense KCPL incurred after the end of the true-up period in one case was deferred until the next rate case for consideration of recovery.

In Case No. ER-2012-0174 ("2012 Rate Case"), Staff returned to its more typical normalization approach for establishing an ongoing level of rate case expense to include in KCPL's revenue requirement because the four Regulatory Plan rate cases were completed. However, there were still amounts included in the 2012 Rate Case (the last of the four Regulatory Plan rate cases) for the amortization of 2010 Rate Case deferred rate case expense consistent with the Regulatory Plan. In the current case, Staff has recognized the recovery of the final vintage of deferred and amortized rate case expense incurred in the 2010 Rate Case.

b. Recommendation

In addition to recognizing the end of the amortizations of the rate case expenses KCPL incurred for the four rate cases addressed in its Regulatory Plan (Adjustment E-218.4 discussed by Keith Majors elsewhere in this report), Staff is recommending the Commission use for rate case expense in this case half of KCPL's normalized prudently incurred costs. Staff's position regarding 50% ratepayer recovery is discussed by Staff witness Keith Majors. Rate case expense accumulated by KCPL as of December 31, 2014 equals $218,318. Half of this amount recovered over a three year period translates into an annual $36,386 of rate case expense recovery. This amount would not be subject to true-up for actual expense incurred, or any over or under-recovery recognized.

Since rate case expense is typically end-loaded (i.e. a material amount of cost is incurred near the end of the case, i.e. evidentiary hearings), Staff's examination of rate case expense resulting from this case is not complete. Staff will continue to examine this case's rate case expense to verify that costs are reasonable and prudently incurred and update total rate case expense. Staff's rate case expense recommendation in this case represents a normalized amount and should not be tracked for under or over recovery after this rate proceeding.

Staff Adjustment E-218.2 includes Staff's recommended rate case expense in this case. Staff Adjustment E-218.3 spreads the cost recovery of KCPL's depreciation study over five years, the required time-interval for KCPL to conduct depreciation studies. Staff Adjustments E-218.5 and E-218.6 remove rate case expense amortizations from the test year.

Staff Expert/Witness: Matthew R. Young

c. Rate Case Expense Sharing Recommendation

Rate case expense can be defined as all incremental costs incurred by a utility directly related to an application to change its general rate levels. These applications are usually initiated by the utility, but rate case expenses may also be incurred as a result of the filing of an earnings complaint case by another party. The largest amounts of rate case expense usually consist of costs associated with use of outside witnesses/consultants and outside attorneys hired by the utility to participate in the rate case process.

Generally, utility management has a high degree of control over rate case expense. Attorneys, consultants, and other services can either be provided by in-house personnel or can be procured by an outside party. Some Missouri utilities do not employ in-house counsel, therefore use of outside attorneys in rate proceedings is necessary. However, KCPL current employs in-house several attorneys with significant prior experience in Missouri rate proceedings. Rate case expenses generally do not include internal labor costs as those are included in the cost of service through the payroll annualization and are not incremental expenses.

During rate proceedings, and generally in the utility regulatory process, there are four broad categories of costs involved:

1) The cost incurred by the Commission for itself and its Staff;
2) The cost incurred by the Public Counsel;
3) The cost incurred by interveners in Commission proceedings; and
4) The cost incurred by the utility in the regulatory process.

Category 1 is the cost incurred by the Commission. This includes all operating expenses, salaries, wages, and benefits of the Commission and its Staff. The Commission's operating expenses are limited to the amount the Missouri General Assembly appropriates for that purpose. An annual amount of operating expenses are assessed by the Commission and paid by the utilities it regulates. The utility, in turn, passes on this expense to its rate payers through the rate case process. The utility is not charged the direct cost of processing its filings or regulating company specific activities. KCPL is charged based on an assignment of the Commission's budget to regulation of the electric industry with this amount allocated to KCPL based on the percentage of KCPL regulated revenues of the total electric regulated revenues in Missouri.

Category 2 is the cost incurred by Public Counsel. Public Counsel represents the public and interests of utility customers in proceedings before the Commission. An amount for Public Counsel's annual operating expenses is appropriated by the Missouri General Assembly which is sourced from the Commission's assessment.

Category 3 is the cost incurred by interveners in Commission proceedings. Interveners may be involved in Commission proceedings for a variety of reasons, but most frequently related to revenue requirement and rate design issues raised in general rate proceedings. Some intervening parties represent large individual utility customers or group of customers. There are several interveners in this case, some of whom have retained their own counsel and experts to review KCPL's rate increase. Each intervener is responsible for its rate case expenses.

Category 4 is the cost incurred by the utility in the regulatory and rate setting process. The Commission has generally allowed utilities to pass through to ratepayers the full amount of normalized and prudently incurred rate case and regulatory expenses to its rate payers in the rate setting process.

Of the four above listed categories, the utility is the only party in the rate case process that does not face an inherent limit in the amount of rate case expense it chooses to incur. The other three categories of rate case participants are limited in the amounts of rate case expense they can incur by the budgetary decisions of the General Assembly or by the willingness of the intervening parties to fund rate case activities. However, the utilities are free to plan their rate case activities with the knowledge that the associated cost of those activities is highly likely to be passed on to a third party; i.e., its customers given current Commission practice.

Both ratepayers and shareholders benefit from the rate case process. Customers have a vested interest in ensuring that they pay just and reasonable rates for safe and adequate service and shareholders have a vested interest in ensuring an opportunity to receive a reasonable return on their investment. If the utility determines that the rates it charges its customers are inadequate, the rate making process before the Commission is the sole venue to remedy that situation. However, the rate case process in Missouri is, at least in part, premised upon an assumption that the utility is not likely in all circumstances to act in the best interests of its customers. This assumption points out the inequity of having customers finance a utility's efforts to increase rates that may be ultimately found by the Commission to be excessive or unreasonable in amount.

The current practice of allowing a utility to recover all, or almost all of its rate case expense from customers creates a disincentive to control rate case expenses incurred by the utility. For all other parties to the rate case process, the funds spent are ultimately limited by a budget and financial restraints. Having significant financial resources to fund rate case activities combined with the ability to pass through the entire amount of expenses create what can be perceived as an unfair advantage over all other parties in the rate case process.

Some expenses incurred for which the utility has a high level of discretion and control are not recovered by the utility in the ratemaking process, even if such expenditures are considered "prudent" from the perspective of the utility. For example, charitable donations have historically not been an includible expense in the cost of service. Donations are defined as discretionary amounts paid to individuals or organizations for charitable reasons, with no direct business benefit. While the utility may have a responsibility to be a "good corporate citizen", charitable contributions, if included in the cost of service, would equate to an involuntary contribution by the rate payer. Costs associated with political activities ("lobbying") are another type of cost usually not allowed to be included in customer rates. These are costs not necessary to the provision of utility service in Missouri. Certain areas of the utility's rate case are not necessary to the processing of a rate increase request. For example, Staff has seen that time and resources for a rate filing can be reduced by pre-case discussions and information.

On April 27, 2011, the Commission issued an Order establishing Case No. AW-2011-0330, and within this docket directed its Staff to investigate the Commission's current rules and practices regarding recovery of rate case expense in rates by Missouri utility companies. In particular, the Commission asked whether the current policy of generally allowing rate recovery of the entire amount of a utility's incurred rate case expense should be changed either by assigning some portion of these costs to the utility's shareholders, or instituting an overall "cap," or limit, on the amount of recovery of rate case expense in rates by utilities. The Commission stated its concern over rate case expense issues was related to testimony presented in recent rate cases and the recent escalation in the amount of claimed rate case expenses by Missouri utilities. As part of its investigation into these matters, the Staff was directed to investigate the practices of other public utility commissions regarding rate recovery of rate case expense.

Several alternative approaches were discussed by the Staff for the Commission's consideration in its Report in Case No. AW-2011-0330 that was filed in September 2013. One of the options for rate case expense recovery presented in Staff's Report was a 50/50 sharing of rate case expenses. This approach would divide expenses equally between the two competing parties that benefit from regulatory and rate case proceedings: shareholders and ratepayers. Staff concludes that a 50/50 share of these expenses is appropriate in this proceeding for the following reasons:

1) A sharing mechanism creates an incentive, and eliminates a disincentive, on the utility's part to control rate case expense to reasonable levels;
2) Considering that ratepayers currently pay for the entire rate case and regulatory process, it is fair and equitable to ask shareholders to pay for at least some of these expenses;
3) Both ratepayers and shareholders benefit from the rate case process; the ratepayer receiving safe and adequate service at a just and reasonable rate, and

the shareholder receiving an opportunity to receive an adequate return on investment; and

4) KCPL in recent cases has incurred rate case expenses substantially higher than historical levels, and higher than other large utilities in Missouri. A sharing mechanism creates an incentive to reduce rate case expense to more reasonable levels.

Staff witness Matthew R. Young has identified the actual rate case expenses incurred by KCPL as of December 31, 2014. Staff included 50% of a three year normalized amount rate case expense in the cost of service.

Staff intends to examine sharing options for rate case expense in future general rate proceedings for major utilities, and may advocate a different approach to sharing, or different sharing percentages, depending upon the circumstances of each individual filing.

Staff Expert/Witness: Keith Majors

14. <u>Regulatory Assessments</u>

a. Public Service Commission Assessment Fee

The Public Service Commission assessment ("PSC Assessment") is an amount billed to all regulated utilities operating under the jurisdiction of the Commission as an allocation of the Commission's operating costs for regulating those utilities. KCPL's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2015) on information obtained from the Commission's records. The updated KCPL PSC Assessment was compared to the PSC Assessment amount included in KCPL's test year to form the basis for the adjustment in Staff's cost of service run. Staff witness Karen Lyons addresses the FERC Assessment adjustment below. Adjustment E-212.1.

b. FERC Assessment

KCPL is also assessed a regulatory fee from the Federal Energy Regulatory Commission ("FERC"). Staff included an annualized level of the FERC assessment based on the 12 month period of December 31, 2014. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment E-210.1.

Staff Expert/Witness: Joel A. Molina and Karen Lyons

15. Customer Deposits – Interest Expense

Staff's recommended treatment of interest expense on customer deposits is to include the interest expense in the expense portion of the revenue requirement calculation, since customer deposits were deducted in the calculation of rate base. Staff recommends that the appropriate amount of interest expense is the amount KCPL paid Missouri customers for interest on their customer deposits. Staff calculated the interest for customer deposits consistent with the level of customer deposits reflected in the Rate Base -- Schedule 2 (see discussion in the Rate Base section of this report for Customer Deposits included in rate base). For this calculation, Staff used the method outlined in the Company's tariff which is to use the customer deposit balance to be included in rate base, and then multiply that number by the most current prime interest rate published in the Wall Street Journal (3.25) plus 1%, for a total of 4.25%. The amount of interest relating to customer deposits has been included as an adjustment to the Income Statement - Schedule 9. The Commission should base its awarded revenue requirement on Staff's recommended amount of interest relating to customer deposits by including the customer deposit interest expense amount calculated by Staff as an expense adjustment to KCPL's income statement. Adjustment E-167.2, E-167.3.

Staff Expert/Witness: Joel A. Molina

16. Depreciation - Clearing

During the test year, KCPL included depreciation for transportation equipment that was charged to expense through a clearing account. Staff made an adjustment to remove the depreciation amount booked to the clearing account. Adjustment E-126.1.

Staff Expert/Witness: Joel A. Molina

17. Economic Relief Pilot Program

The Economic Relief Pilot Program (ERPP or "Program") offered by KCPL provides an opportunity to relieve the financial hardship experienced by some KCPL customers. The current program is open to income eligible customers, defined as an annual household income no greater than 185 percent of the Federal Poverty Level (FPL), used to determine eligibility for certain programs and benefits. The FPL has increased to 200 percent from the previous level in the definitions of the current tariff sheet.

The program currently delivers up to \$50 dollars per month "fixed credit" to income eligible customers to help improve energy affordability. The current ERPP is designed to provide assistance for up to 1,000 participants, with 50 percent of the costs of the programs being covered by ratepayers, and 50 percent of the costs being covered by KCPL's shareholders.

KCPL is proposing to continue with the ERPP and to double the amount of available funds for the ERPP. Currently, the program is valued at \$630,000, funded half through shareholder dollars and half by the rate payers. The proposed modification would double funding with KCPL shareholders covering \$630,000 and the ratepayers another \$630,000 making total funding \$1,260,000. KCPL is also proposing to raise the current limit of 1,000 customer participants to 1,500 and increase the available monthly bill credit from \$50 to \$65.

KCPL also proposes to change the procedure for any unused funds in the ERPP. Currently unused funds are used to offset demand-side management (DSM) programs. Recently KCPL received approval to offer its DSM programs under the Commission's MEEIA rules. Given the recent change KCPL is proposing to use unspent ERPP dollars to fund another of its assistance programs known as Dollar-Aide.

Staff recommends the program continue at the current funding level of \$630,000 due to a surplus of \$654,980 showing the current funding level is not being utilized in its entirety each program year. Staff has submitted data requests for additional information to determine if the data supports a funding level increase. Currently, there is a surplus and KCPL has provided no data to support doubling the amount contributed for each program year. Staff also recommends approving KCPL's request to increase the number of customers enrolled each month from 1000 to 1500. Due to the FPL rate increasing in 2009, Staff would further recommend KCPL change the eligibility requirement from 185% of FPL to 200% of FPL on Tariff Sheet No. 1.91 program 22.12 to reflect the current FPL.

Staff Expert/Witness: Kory Boustead

a. Accounting Treatment

Since February 2013, the effective date of new rates from KCPL's last rate case, Case No. ER-2012-0174, KCPL and its customers have provided an annual \$315,000 each for the purpose of funding the ERPP. According to KCPL's response to Staff Data Request No. 0445. KCPL's ERPP expenditures have not equated to the funding provided for the program, resulting in an over-funding. As of the update period in this case, Staff has calculated $654,980 of funds collected, but not spent, that is earmarked for the ERPP. Staff recommends the unspent funds collected between February 2013 and December 2014, the update period in this case, as well as additional unspent funds collected after December 31, 2014 be made available for future ERPP expenditures.

In ER-2010-0355 and ER-2012-0174, two vintages of ERPP (one vintage per case) deferred ERPP costs were established and amortized. Since the total deferred ERPP costs have been recovered through rates, Staff made Adjustment E-175.3 to remove the amortizations from the test year.

Staff Expert/Witness: Matthew R. Young

18. Income Eligible Weatherization Program (formally Low Income Weatherization Program)

The funding for KCPL's Income-Eligible Weatherization Program ("Program") was established and ordered to be included in rates in Case No ER-2012-0174. On July 6, 2014, KCPL's Missouri Energy Efficiency Investment Act (MEEIA) cost recovery mechanism became effective. Eligible costs to be recovered under the MEEIA rider include expenditures for the Program and consequently, KCPL will continue to collect funds in rates earmarked for the Program (base rates have not changed since the MEEIA rider became effective). Program costs will also be recovered through the MEEIA rider.

The November 7, 2012 Commission Order in ER-2012-0174 approving the "Non-Unanimous Stipulation and Agreement Regarding Low-Income Weatherization" approved the following agreement:

> In regard to KCPL, KCPL's low-income weatherization program should be funded (included in cost of service) at $573,888 annually; however, this low-income weatherization program should not be funded in rates at the same time KCPL's retail customers are funding a low-income weatherization program the Commission approves under the MEEIA, if any. (Both programs are not funded at the same time and they are mutually exclusive.)
>
> Any low-income weatherization funds which KCPL collects through its rates during a year which are not distributed to the low-income weatherization agencies during that year will be available for distribution in subsequent years.

KCPL's MEEIA rider became effective on July 6, 2014 and KCPL still continues to collect for the program in base rates. Since all Program expenditures are eligible for recovery through the MEEIA rider, funds collected in base rates will not be applied to program expenditures. Also, KCPL has experienced barriers that prevented the Company from spending Program funds prior to the effective date of the MEEIA environment. The largest intended recipient of KCPL Program funding, City of Kansas City, discontinued its Weatherization Program in 2013. During the period after which the Kansas City stopped taking funding and prior to the time a new vendor, United Services Community Action Agency was selected, Program funds collected by KCPL were not distributed. Due to KCPL's inability to use these Program funds (both pre and post MEEIA), there will be a surplus of $1,105,850 as of the effective date of rates in this case. Staff proposes the surplus of Program funds be used to offset any expenditures relating to the Program through KCPL's MEEIA recovery mechanism.

The test year period from April 1, 2013 through March 31, 2014 included Program funding and expenses. Therefore, the test year Program expenditures are not an ongoing expense. Staff made an Adjustment (E-175.2) to remove the Program expenses from the revenue requirement calculation of this rate case.

Staff Experts/Witnesses: Kory Boustead, Thomas M. Imhoff and Matthew R. Young

19. SPP Administrative (Schedule 1-A) Fees

The Southwest Power Pool (SPP) is a not-for-profit, regional transmission organization (RTO) entity which maintains functional control over the transmission assets of its members and provides transmission services through its Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff ("Open Access Tariff" or "OATT"). SPP's costs must be recovered from its users (transmission customers, which, in this case, are utility companies such as KCPL, GMO, The Empire District Electric Company, Westar Energy, Inc. and many other electric companies). Consequently KCPL pays SPP an administration charge for performing transmission functions on its behalf.

Under its Open Access tariff, SPP establishes a rate for its administration charge annually that enables it to recover 100% of its total annual administrative costs for RTO functions, subject to a rate cap. The rate cap serves as a limit on the annual administration charge in order to provide SPP customers a level of certainty and predictability regarding SPP's year-to-year administrative costs. SPP's administrative rate cap is currently \$.39 per MWh. The following chart reflects the increase in SPP's administrative fee rate for the period of 2006-2015.

Historical SPP Administrative Fee per Mwh										
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Rate	\$.16	\$.19	\$.19	\$.17	\$.195	\$.210	\$.255	\$.315	\$.381	\$.39

On January 27, 2015, SPP's Board of Directors approved the Finance Committee's 2015 budget. The Finance Committee recommended an assessment rate and tariff administrative fee of \$.39 per MWh beginning on January 1, 2015, which effectively serves as a cap for 2015 costs. Although this rate increased slightly for 2015, a higher rate was initially supported by the Finance Committee. In an effort to reduce costs the Finance Committee recommended several changes. Listed below are a few examples of cost reductions recommended by the Finance Committee and approved by the Board of Directors[62]:

- Reduction in Pension Funding,
- Reduction in SPP Personnel Headcount
- Reductions in IT Consultants and Maintenance
- Reduction in Outside Services and Travel
- Elimination and delays on specific studies performed by SPP

Staff annualized SPP administration fees based on the administrative rate of \$0.39 per MWh effective January 1, 2015. Included in the annualized amount are North American Electric Reliability Corporation ("NERC") fees and Midwest Independent Transmission System Operator ("MISO") RTO administrative fees for point to point transmission. Staff's adjustments for SPP Administration fees are identified on Schedule 9 of Staff's Accounting Schedules, Adjustment E-119.2 and E-126.1.

Staff Expert/Witness: Karen Lyons

[62] October 13, 2014, SPP Financial Committee Meeting.

20. Transmission Expense-FERC Account 565

KCPL and GMO are members of the SPP. In 2004 SPP became a regional transmission operator ("RTO") responsible for ensuring reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices.[63] Prior to 2006, KCPL had full functional control over its transmission system that served its retail customers within its service territory. In Case No. EO-2006-0142, KCPL filed an application with the Commission to transfer functional control of its transmission facilities to SPP. Most of the parties to this case entered into a Stipulation and Agreement on February 24, 2006, and the Commission approved the Stipulation and Agreement by Order effective on June 23, 2006. The transfer of functional control of KCPL's transmission system to SPP was finalized upon the approval by the FERC on October 1, 2006.

As a transmission customer of SPP, KCPL is charged for point-to-point, base plan zonal and region-wide transmission costs that are booked to FERC Account 565. Point-to-point transmission costs are billed based on Schedule 7 and Schedule 8 of SPP's Open Access tariff. Base-plan-zonal charges and region-wide charges are billed based on Schedule 11 of the Open Access tariff.

Base-plan-zonal and region-wide costs are a result of transmission upgrades in the SPP region. The transmission upgrades are directed by SPP's Transmission Expansion Plan in place to ensure the reliability of the transmission system for SPP's members.[64] The costs of base-plan and region-wide projects are allocated to the SPP region based on the voltage of the project. The allocation method is referred to as the Highway-Byway method and is shown in the following table:

SPP Base Plan Highway-Byway Allocation Method		
Voltage	Regional (SPP region)	Zonal (KCPL region)
300 kV and Above	100%	0%
100-300 kV	33%	67%
Below 100%	0%	100%

[63] Market Protocols for SPP Integrated Marketplace, p. 60.
[64] SPP OATT Tariff.

The costs allocated to the SPP region are then allocated to SPP transmission customers based on a load share. The load share ratio is developed using the transmission customer's network load divided by the SPP total load. KCPL's load share on a total company basis is currently 7.76%. GMO's share is approximately 4%.

In its direct case, KCPL proposed adjustments to annualize transmission expense booked to FERC Account 565 and an adjustment to eliminate costs and revenues related to region-wide projects completed by KCPL based on a SPP Notice To Construct ("NTC"). These projects will be discussed later in this report.

Staff analyzed KCPL's transmission expenses and revenues for the period of 2009 through 2014. Staff's recommendation for KCPL's transmission revenues are addressed in more detail in the "Transmission Revenue- FERC Account 456" section of this report. KCPL's transmission expenses for the 12-month period ended December 31, 2014, have ** ____________ ** over the 12-month period ended December 31, 2009. On the other hand, KCPL's transmission revenues have ** ____________ ** for the same period. The following chart reflects KCPL's historical transmission expenses and revenues for the period of 2009-2014.

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Based on Staff's analysis, KCPL's transmission expenses have significantly increased during those six years. Consequently, Staff included an annualized level of transmission expense based on the 12-month period ended December 31, 2014, the most recent costs available. Staff's adjustment for transmission expense is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment E-123.1. Since KCPL's transmission expense has significantly escalated, Staff will review this adjustment in its True-Up audit based on updated events and cost information.

As mentioned above, KCPL also proposed to eliminate costs and revenues related to a region-wide project it constructed based on a SPP "Notice To Construct." A "Notice To Construct" is a written notice from SPP notifying KCPL that it has been selected to construct one or more regional transmission project(s).[65] KCPL received a Notice To Construct from SPP on February 13, 2008, to upgrade the West Gardner transformer. In addition, KCPL received a Notice To Construct from SPP on June 19, 2009, directing the following network upgrades. The Notices To Construct are attached as Appendix 3, Schedule KL-1:

- Swissvale-Stilwell Tap
- Iatan-Nashua 345 kV line
- Nashua 345/161 kV Transformer

The Iatan-Nashua 345 kV line and Nashua 345/161 kV Transformer projects were transferred to Transource Missouri LLC ("Transource Missouri") after receiving approval from the Commission in Case No EA-2013-0098.

The Swissvale-Stilwell Tap and Stilwell-West Gardner Substation upgrades were placed in service on January 31, 2013, and are within KCPL's service territory and therefore regulated utility assets which should be included in KCPL's cost of service. As discussed above, KCPL eliminated the costs and revenues related to these projects in its updated direct case. The costs include actual plant in service and accumulated depreciation reserve as of December 31, 2014. KCPL also eliminated actual revenues and a projected level of expense for these projects in the test year, the 12 months ended March 31, 2014.

Since the Swissvale-Stilwell Tap and Stilwell-West Gardner Substation upgrades were made to KCPL's regulated utility assets, Staff included the actual plant in service and accumulated depreciation reserve as of December 31, 2014, and included any revenues and

[65] SPP tariff, p. 66.

expenses related to these projects in KCPL's cost of service as of the test year, the 12 months ended March 31, 2014.

Staff Expert/Witness: Karen Lyons

21. 2011 Missouri River Flood Incremental Non-Fuel Operations & Maintenance (NFOM) Expense

The Commission authorized KCPL to defer the incremental $1.4 million Missouri jurisdictional NFOM expense related to the 2011 Missouri flood into a regulatory asset with amortization over 5 (five) years beginning with the effective date of rates in Case No. ER-2012-0174.

The test year ending March 31, 2014 includes a full 12 months of amortization related to these deferred expenses; therefore, no adjustment is necessary.

Staff Expert/Witness: Keith Majors

22. 2011 Missouri River Flood Insurance Reimbursement

KCPL received insurance proceeds in March and August of 2013 related to the impact of the 2011 Missouri River flooding. Staff recommends a three year amortization of these proceeds as a reduction to the cost of service. Staff Adjustments E-4.2 and E-195.7 in Schedule 9 – Income Statement reflect this amortization.

Staff Expert/Witness: Keith Majors

23. Meter Replacement Program – Incremental Meter Reading Costs

In 2014, KCPL began installing Advanced Metering Infrastructure (AMI) technology that will replace all of the Company's Automated Meter Reading ("AMR") meters by the end of 2015. KCPL has identified an unrecovered depreciation reserve amount associated with the replaced AMR meters. Staff witness Derick A. Miles discusses the Staff's treatment of the unrecovered reserve elsewhere in this report. KCPL has entered into a new meter reading contract associated with the newly installed AMI meters. The new contract increases the composite meter reading cost from $0.52 per meter to $0.61 per meter. Staff Adjustment E-165.2 reflects the incremental meter reading cost associated with the new AMI meters.

Staff Expert/Witness: V. William Harris

24. Research and Development Tax Credit Amortization

In Case No ER-2007-0291, the parties entered into a Non-Unanimous Stipulation and Agreement as to Certain Issues (Agreement) that was approved by the Commission on December 6, 2007 at the time of the Commission's issuance of its Report and Order allowing KCPL to establish a regulatory asset for consulting fees related to research and development tax credit studies. In the Agreement in Case No. ER-2007-0291, the Parties to the Agreement stated:

> The Parties agree to reverse the Missouri jurisdictional consulting expenses incurred related to the research and development tax credit studies from the Company's cost of service, and set up a regulatory asset for the expense. The Parties agree also to set up a regulatory liability for the Missouri jurisdictional research and development tax credits included as adjustments on the 2000-2005 amended tax returns filed in 2007. Both the regulatory asset and the regulatory liability will be amortized over five years beginning on the effective date of the new rates in the first general rate case following the receipt of the refunds by the Company.

The amortization period began the effective date of rates for Case No. ER-2009-0089, September 1, 2009 and ended on August 31, 2014. Staff made an adjustment to remove the amortization included in the test year, the 12-months ended March 31, 2014. Further, Staff requests that KCPL be ordered to track any amounts of over collection for regulatory assets and any amounts of over payments for regulatory liabilities, which is the case for research and development tax credit studies, that results from the amortization ending March of 2014 through the effective date of rates ordered in this case to use in future rate case as offsets for over collections or other expiring amortizations. This is consistent with the treatment that Staff has recommended regarding other amortizations in this case. Staff's adjustment to remove the amount recorded by KCPL in the test year related to the expiring Research and Development Tax Credit studies amortizations is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment E-200.3.

Staff Expert/Witness: Karen Lyons

25. Amortization of Regulatory Liabilities & Assets

A regulatory liability is a dollar amount on a utility's books that is used to reduce a utility's cost of service and a regulatory asset is a dollar amount on a utility's books that is used to increase a utility's cost of service. Both regulatory liabilities and regulatory assets are amortized over what is determined to be an appropriate number of years, and the resulting annual amount is included in the utility's cost of service used for setting its rates. KCPL has both regulatory liabilities and regulatory assets on its books.

The table below shows the balances of KCPL regulatory liabilities at this date, as well as the balances at the end of the update period and what the balances will be at the anticipated effective date of rates in this case. A negative balance reflects the amount KCPL's customers received through rates in excess of the amount of the liability. A positive balance reflects the amount of the liability that KCPL's customers have not yet received.

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Regulatory Liability	End date of amortization	Annual Amortization	Balance at December 31, 2014	Balance at May 31, 2015	Balance at September 2015
Legal Fee Reimbursement One	April 2014	$317,092	($211,395)	($343,517)	($449,214)
Legal Fee Reimbursement Two	January 2016	$335,057	$362,978	$223,371	$111,686
Research & Development Tax Credit (Liability and Asset Netted)	August 2014	$44,737	($14,912)	($33,553)	($48,466)
Total Net		$696,886	$136,671	($153,699)	($385,994)

The amortization of Legal Fee Reimbursements One and Two were removed from the test year because, by the time of the true-up, KCPL customer over-recovery of One more than offsets KCPL customer under-recovery of Two. Staff also removed the liability and asset amortizations related to the Research & Development (R&D) Tax Credit because they are fully amortized (the period of years over which they are to be recovered has ended) by the end of the update period. As of the May 31, 2015, end of the true-up period, the net balance of these liabilities is ($153,699), which means that, on the whole, KCPL's customers will have received more benefit in their KCPL bills than the total amount of the liabilities.

In addition, KCPL amortizes several regulatory assets on its books and records. The Commission authorized these regulatory assets in various cases. A regulatory asset represents an amount that a utility is to recover from its customers through rates by amortizing the asset amount over an appropriate number of years and then including the annual amortization amount in the utility's cost of service. The table below shows the balances of KPCL regulatory assets at this date, as well as the balances at the end of the update period and what the balances will be at the anticipated effective date of rates in this case. A positive balance reflects the amount KCPL receives in excess of the amount of the asset. A negative balance reflects the amount that KCPL still has not received.

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Regulatory Asset	End Date of Amortization	Annual Amortization	Balance at December 31, 2014	Balance at May 31, 2015	Balance at September 2015
2010 Rate Case Expense – Vintage 1	April 2014	$1,294,629	$863,086	$1,402,515	$1,834,058
2010 Rate Case Expense – Vintage 2	January 2016	$264,262	($286,284)	($176,175)	($88,087)
Wolf Creek Refueling No. 16	August 2014	$314,116	$104,705	$235,587	$340,292
Economic Relief Pilot Program (ERPP)	April 2014	$85,642	$57,095	$92,779	$121,326
Total Net		$1,958,649	$738,602	$1,554,706	$2,207,589

The amortizations of 2010 Rate Case Expense Vintages 1 and 2 were removed from the test year because KCPL's over-recovery of 2010 Rate Case Expense--Vintage 1 more than offsets the remaining unrecovered balance of 2010 Rate Case Expense--Vintage 2, as of the end of the update period and thereafter. Staff has applied the over-collection of Wolf Creek Refueling No. 16 to other outstanding amortizations of Wolf Creek related deferrals. Staff Expert/Witness Kory Boustead recommends that any ERPP fund surplus be used for ERPP program, as described in the ERPP section of this report.

The remaining over-amortizations are the Legal Fee reimbursements, the R&D Tax Credit, and the 2010 Rate Case Amortizations. Staff recommends that the Commission offset these amortizations against each other, order that the net amount be amortized over three years, and order that the resulting annual amortized amount be included in KCPL's cost of service for setting rates in this case. Staff has captured the amount as of May 31, 2015, and recommends that the annual amount based on a three-year amortization be applied as a reduction to KCPL's cost of service:

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Regulatory Liability	**Balance at May 31, 2015**	**Balance at September 2015**
Legal Fee Reimbursement One	($343,517)	($449,214)
Legal Fee Reimbursement Two	$223,371	$111,686
Research & Development Tax Credit (Liability and Asset Netted)	($33,553)	($48,466)
Sub-Total Net (over-amortization)	($153,699)	($385,994)
Regulatory Asset	**Balance at May 31, 2015**	**Balance at September 2015**
2010 Rate Case Expense – Vintage 1	$1,402,515	$1,834,058
2010 Rate Case Expense – Vintage 2	($176,175)	($88,087)
Sub-Total Net (over-collection)	$1,226,340	$1,745,971
Total Net (over-collection)	**$1,072,641**	**$1,359,977**
Three Year Amortization	**$357,547**	**$453,326**

This amount is 100% Missouri jurisdictional. Because the majority of the over-collection is related to the amortization of 2010 Rate Case expenses (Vintage 1 and Vintage 2), Staff adjusted Account 928 – 100% Missouri to reflect this amortization. Staff Adjustment E-218.4 in Schedule 9 – Income Statement reflects this amortization.

Staff Expert/Witness: Keith Majors

26. KCPL Affiliate Transactions, Quality of Service, and Other Concerns Related to Allconnect, Inc.

As expressed in the "Report of Staff's Investigation Case No. EO-2014-0306 Allconnect Direct Transfer Service Agreement Between Allconnect, Inc., And Great Plains Energy Services Incorporated Respecting Itself And Its Affiliates" (herein referred to as the "Staff Allconnect Report") Staff has significant affiliate transactions, service quality, and other concerns regarding KCPL and KCPL Greater Missouri Operations Company's utilization of Allconnect, Inc. ("Allconnect") and its impact on and consequences for KCPL and GMO's customers.[66] Staff's report was filed with the Commission on December 19, 2014 in File No. EO-2014-0306.

Among the Staff's concerns are the "forced" customer call and customer information transfers from KCPL to Allconnect, Inc. of new and existing KCPL customers who are initiating service for the first time or are transferring service within KCPL's Missouri service territory. KCPL receives ** ____ ** from Allconnect for each customer call transferred as well as ** ______________________________ ______________________________ ________ ** [67] Customers are given no indication that they have the option or may decline such call transfers, and in contrast are instructed that their calls are being transferred to "verify the accuracy of their order" and/or for verification of their customer information and to be provided a confirmation number.[68]

Prior to its 2013 contract with Allconnect, KCPL provided confirmation numbers regarding service requests directly to its customers. There is no indication that KCPL customer representatives are not qualified or able to verify the customer information that the Allconnect customer representatives confirm. To the contrary, KCPL representatives are evaluated on verifying and documenting customer information.[69]

KCPL has turned over to Allconnect the resolution of KCPL customer complaints related to Allconnect when KCPL customers did not request, approve or agree to their calls or

[66] Although the Staff's concerns also involve GMO, only KCPL has filed a rate case. As a consequence, the Staff will only refer to KCPL, even though its concerns are identical for GMO.
[67] File No. EO-2013-0011 Company Data Request Response No. 71.
[68] File No. EO-2014-0306 Company Data Request Response Nos. 50 and 51, the KCPL/GMO calls provided to Staff on CD, scripted recording to KCPL/GMO customers while holding for transfer to Allconnect, after KCPL service representatives left the calls.
[69] File No. EO-2014-0306 Company Data Request Response No. 52.

information being transferred to a marketing entity.[70] KCPL is in violation of Commission Rule 4 CSR 240-13.040(2)(A) which provides that qualified utility personnel should be available and prepared to respond to customer inquiries and complaints. Allconnect customer representatives are trained for, charged with, and evaluated on making sales, which is not the role of KCPL customer representatives. Such call and information transfers are detrimental to the customers KCPL serves by exposing customers to sales of other services that KCPL customers did not initiate the call for, may or may not want, and which may or may not be in the customers' best interest. Staff is presently aware of no other Missouri regulated utility that requires or depends upon third-party review of data being inputted into its system and involvement regarding call center quality control.

The Allconnect Direct Transfer Service Agreement requires the use of Allconnect's "confirmation" model / no customer consent model rather than Allconnect's "transfer" model / customer consent model which KCPL utilized from 2005 to 2007.[71] Staff believes the relationship between KCPL and Allconnect violates the Commission's Affiliate Transactions Rule, 4 CSR 240-20.015(2)(C), which requires customer consent when specific customer information is made available to affiliated or unaffiliated entities. The Allconnect contract is between Great Plains Energy Services Incorporated ("GPES") and Allconnect, Inc. GPES has no contract with KCPL or GMO authorizing GPES to sign contracts on either's behalf.

The Staff Allconnect Report also presents that KCPL is in violation of Section 393.190.1, RSMo. 2000, by not seeking Commission authorization before entering into the Allconnect Direct Transfer Service Agreement (Staff concludes KCPL is selling, transferring, and/or disposing of a portion of its works or system necessary or useful in the performance of its duties to the public without first obtaining Commission authorization). The Staff Allconnect Report documents customer service concerns of Staff within the KCPL and Allconnect relationship.

Allconnect is unable to offer customers a complete list of service providers for the home services it sells but customers are not informed that such lists may be incomplete. In addition, Allconnect representatives are trained and evaluated on their ability to "rebut" customer

[70] File No. EO-2013-0011 Company Data Request Response No. 17, Company Data Request Response No. 87 and File No. EO-2014-0306 Company Data Request Response No. 26.
[71] File No. EW-2013-0011 Company Data Request Response No. 13 and File No. EO-2014-0306 Data Request Response No. 44.

objections to Allconnect sales offerings.[72] The Staff Allconnect Report included documentation of customer reports of "pushy" or "aggressive" Allconnect behavior and Staff had observed such behavior while listening to Allconnect call recordings. Customer satisfaction survey information highlights concerns with KCPL's relationship with Allconnect, with 14% of KCPL customers stating that their contact with Allconnect negatively impacted their perception of KCPL.[73] For one period of time examined, 32 to 34 % of KCPL customers purchased at least one service from Allconnect[74] and KCPL indicates it has no data in its possession to demonstrate how many of those initial service orders are ultimately cancelled.[75]

Staff witness Charles R. Hyneman is sponsoring specific adjustments to KCPL's test year books and records to remove any impact related to KCPL's association with Allconnect, Inc. Staff is currently researching privacy rules of other state utility commissions and may request this Commission consider similar rule-making in the future. Staff will shortly file a Staff Complaint addressing the Allconnect matters noted above and addressed in detail in File No. EO2014-0306.

Staff Expert/Witness: Lisa A. Kremer

27. Affiliate Transactions / Corporate Allocations

In this rate case the Staff performed a review of KCPL's affiliate transactions and corporate allocations. This review was performed in conjunction with Staff's current review in File No. EO-2014-0189. In its this report Staff is proposing five adjustments related to KCPL's affiliate transactions and corporate allocations. The first three adjustments relate to KCPL's use of the Massachusetts Formula allocation factor. One adjustment removes the impact of KCPL's transactions with Allconnect, Inc. The final adjustment is a consolidated adjustment designed to reduce the level of risk that KCPL's customers will be significantly harmed through inappropriate cost allocations as well as KCPL's noncompliance with the Commission's Affiliate Transactions Rule.

On December 16, 2013, KCPL filed an Application for approval of its Cost Allocation Manual ("CAM") in File No. EO-2014-0189 ("0189 Case"). This request of KCPL satisfies a

[72] File No. EO-2014-0306 Company Data Request Response No. 32.
[73] File No. EO-2014-0306 Company Data Request Response No. 47.
[74] File No. EO-2013-0011 Company Data Request Response No. 53.
[75] File No. EO-2014-0306 Company Data Request Response No. 65.

condition contained in the Stipulation and Agreement approved by the Commission in File Nos. EA-2013-0098 and EO-2012-0367 ("Transource Cases"). The condition stated that KCPL needed to file a CAM for Commission approval before providing any information, assets, goods, and services to Transource Energy, LLC or Transource Missouri, LLC after either the novation or transfer of the cost of the Iatan Nashua and Sibley-Nebraska City 345 kV regional, high-voltage wholesale transmission projects, whichever occurred first. Transource Energy, LLC ("Transource") was formed in 2012 as a joint venture between Great Plains and American Electric Power Company, Inc. ("AEP") to pursue competitive transmission projects. GPE owns 13.5% of Transource through its wholly owned direct subsidiary GPE Transmission Holding Company, LLC ("GPTHC") with AEP Transmission Holding Company, LLC, a wholly owned subsidiary of AEP, owning the remaining 86.5%.

In cases before the Commission over the past several years Staff has found several instances of noncompliance and has expressed serious concerns with KCPL's noncompliance with the Commission's Affiliate Transactions Rule 4 CSR 240-20.015 ("Affiliate Transactions Rule"). In the 0189 Case, Staff found instances of noncompliance it was not otherwise aware of, and concluded that KCPL's proposed CAM, included with its application in that case, did not provide reasonable assurance that affiliate transactions reporting requirements would be satisfied or that past instances of significant noncompliance would be corrected on a going-forward basis, based on KCPL's proposed CAM.

However, Staff believes that progress has been made in the 0189 Case toward producing a KCPL CAM that, if effectively enforced, will provide reasonable assurance that the overall purpose of the Affiliate Transactions Rule will be met. That overall purpose of the Affiliate Transactions Rule is to "prevent regulated utilities from subsidizing their nonregulated operations." It should be noted that the treatment of customer of information by nonregulated, nonaffiliates is also addressed by the Affiliate Transactions Rule.

One of the problems Staff found both in the 0189 Case and this rate case is the method used by KCPL to allocate certain overhead costs to KCPL affiliates, including its parent company, Great Plains. KCPL has a unique relationship with its affiliated entities which significantly increases not only the likelihood, but also the inevitability that regulated customers will be charged with costs that should be assigned or allocated to affiliates or nonregulated operations.

Within the Great Plains/KCPL corporate framework, all costs of the Great Plains companies are charged to the regulated utility, KCPL. It is then incumbent on KCPL's regulated utility employees to charge its parent company, Great Plains, and all other affiliates and nonregulated operations with their appropriate share of the costs which were first charged to KCPL's books and records. If certain costs are overlooked and/or just not charged to an affiliate or nonregulated activity, they will be retained by KCPL as a KCPL regulated activity and charged to KCPL customers in utility rates.

In contrast to KCPL and Great Plains' corporate structure, other utilities that have significant affiliate transactions and nonregulated operations have a corporate structure that includes a service company. Typically a service company provides goods and services to all entities under the corporate umbrella, including regulated utilities and nonregulated businesses. All costs which benefit more than one entity are initially charged to the service company and the service company then directly charges or allocates costs to the individual companies. This corporate structure, rather than the Great Plains/KCPL corporate structure, lowers the risk of inappropriate charges being made to regulated customers, simply because the costs are initially charged to the service company and not the utility.

KCPL's affiliated entities have no employees and all the operations of these entities are serviced by KCPL employees. It is highly unusual to have the utility employees completely involved in and representing all the interests in an affiliate transaction. KCPL's regulated utility employees are required to represent interests of the regulated utility as well as the interests of the nonregulated affiliates.

It is a major concern of the Staff that the regulated utility KCPL represents both itself and the affiliated entity's interest in every affiliated transaction. Such a situation requires that, at an absolute minimum, there be a very sophisticated set of criteria, guidelines and procedures to reduce the inherent and significant risk of the utility subsidizing its nonregulated affiliates to an acceptable level of risk. KCPL, to this date, has not had such a set of criteria, guidelines and procedures. KCPL's current CAM, which was not approved by the Commission, allows KCPL's customers to subsidize KCPL's affiliate transactions.

Staff is proposing certain adjustments to KCPL's cost of service in this rate case that are related to KCPL's affiliate transactions and its nonregulated operations. The first three adjustments relate to KCPL's current method of allocating certain common costs that were not directly charged to a specific entity and cannot be reasonably allocated using a cost causative allocation factor. An example of a cost-causative allocation factor is the use of square feet to allocate rent expense of a building that serves more than one entity. An example of a cost that cannot be reasonably allocated on a cost causative factor basis is the residual KCPL or Great Plains officer compensation that is not directly assigned to one of the KCPL affiliates. KCPL has historically allocated all of these residual corporate overhead costs using a version of the Massachusetts Formula allocation factor.

KCPL uses two variations of the Massachusetts Formula. One to allocate costs to just the regulated utilities (KCPL and GMO) referred to as the Utility Mass Formula and the other to allocate costs to KCPL and GMO plus other entities who qualify for allocation under the Massachusetts Formula referred to as the Corp Mass Formula.

The Massachusetts Formula allocation factor was developed years ago and is used to allocate costs between regulated utility companies who are comparable in the sense that regulated utilities have significant levels of plant, revenues and payroll. These are the three traditional financial components used in a Massachusetts Formula allocation factor and are the components used by KCPL.

The Massachusetts Formula allocates costs based on a relative weighting of plant, revenues and payroll among the entities included in the allocation. KCPL's use of the Massachusetts Formula is particularly troublesome in the sense that no other entity in the KCPL/Great Plains corporate family has any organic payroll costs. This highly unusual corporate structure results in costs being allocated through the Massachusetts Formula based on the component of payroll that is directly charged to an entity rather than actually being directly incurred by an entity. This is not only a distortion of the general cost allocation process but it allows for significant manipulation of costs allocated to regulated operations rather than to nonregulated operations.

Staff has no problem with the use of the Massachusetts Formula allocation factor for KCPL CAM purposes for specific transactions that are only between the regulated operations of KCPL and GMO. However, Staff has determined that a General Allocator in a format that KCPL adopted for accounting purposes in January 2015 will more equitably allocate common costs among both regulated and nonregulated entities. This is especially true with entities which have many nonregulated entity affiliates such as KCPL.

This General Allocator will allocate residual common corporate overhead costs (currently allocated using the Massachusetts Formula) based on the dollar amount an entity was direct charged and allocated (using other cost causative allocation factors) in relation to other entities in allocation pool. For example, assume that in the test year KCPL had total allocable common corporate overhead costs of $1 million. KCPL's total direct charges and costs allocated using other causative factors was $5 million. Of the $5 million KCPL's affiliate Transource was directly charged and allocated $500,000. In this scenario Transource will be allocated 10% or $100,000 of the residual corporate overhead costs using the General Allocator.

Starting in January 2015 KCPL replaced its Corp Mass Factor with this type of General Allocator. In this rate case, and for the purpose of the three adjustments described below, the Staff used the same General Allocator percentages currently used by KCPL to allocate corporate overhead costs to its books and records. The Staff's adjustment simply adjusts KCPL's test year expenses as if the General Allocator was used to allocate the common corporate overhead costs in the test year.

As noted above, the Staff is proposing five adjustments to KCPL's cost of service that are related to KCPL's accounting for its affiliate transactions and its corporate allocations. The first three adjustments, described below, relate to the Staff's use of KCPL's 2015 General Allocator, rather than the Massachusetts Formula to allocate test year costs:

> Adjustment 1 effectively removes test year expenses charged to KCPL's regulated accounts using the Corp Massachusetts Factor and adds back to test year expenses the charges that would have been made using the 2015 General Allocator.
>
> Adjustment 2 effectively removes test year expenses charged to KCPL's regulated accounts using the Utility Massachusetts Factor and adds back to test year expenses the charges that would have been made using the 2015 General Allocator.
>
> Adjustment 3 restates KCPL's proposed adjustment CS-117 using the General Allocator as opposed to the Corp Mass Factor allocation percentages used in KCPL adjustment CS-117. KCPL's adjustment CS-117 is designed to allocate the benefits of common use plant in service among the entities that benefit from this plant.

The Staff's fourth adjustment removes from KCPL's test year accounts included in its cost of service filing all effects of its transactions with Allconnect, a nonregulated, nonaffiliated contractor with Great Plains Energy Services, Inc. on behalf of itself and its affiliates KCPL and

GMO. The Staff has a number of serious concerns with KCPL's business association with Allconnect, which Staff witness Lisa A. Kremer briefly notes in her section of this report. The Staff filed on December 19, 2014 a Report of Staff's Investigation respecting the Allconnect Direct Transfer Service Agreement in File No. EO-2014-306 and will shortly file a Staff complaint both filings recommending:

Commission Order To KCP&L/GMO To:

- Cease the transfer of customer information and calls to Allconnect until and unless KCP&L/GMO apply for and obtain Commission authorization under Section 393.190.1 RSMo. to sell or transfer certain customer information to Allconnect.

If The Commission Authorizes The Sale Or Transfer Of Customer Information Or Determines That Commission Authorization Is Not Necessary, The Staff Recommends That The Commission:

- Authorize the transfer of customer information and calls to Allconnect only if the customer consents to such transfers.
- Require KCP&L/GMO to verify the accuracy of electric service orders and provide electric service confirmation numbers to its own regulated customers.
- Require KCP&L/GMO to notify the Staff and OPC prior to engaging the services of Allconnect or like marketing or sales companies in the future.
- Require KCP&L/GMO to assume complete responsibility and control of handling and resolving customer complaints related to Allconnect. Require KCP&L/GMO to cease using Allconnect to attempt to resolve such complaints.

Staff's Report, pages 7, 40-41, in File No. EO-2014-306, respecting its Investigation of the Allconnect Direct Transfer Service Agreement and the related activities of Allconnect and KCPL/GMO.

The fifth and final Staff adjustment related to KCPL's affiliate transactions and cost allocations is a consolidated corporate allocations adjustment designed to accomplish three objectives. The adjustment reduces KCPL's overhead expenses by $750,000 on a total company basis.

The first objective is to protect KCPL's customers from KCPL's lack of compliance with the Affiliate Transactions Rule. As noted above, the Staff has found numerous and significant noncompliance with the Affiliate Transactions Rule on the part of KCPL over a long period of time. The financial impact of this noncompliance is reflected in KCPL's test year books and records (KCPL does have noncompliance issues that do not have a financial impact to be reflected in this rate case. Those issues will be addressed in the 0089 Case). While the Staff's use of KCPL's 2015 General Allocator in place of the Massachusetts Formula results in a more equitable allocation of corporate overhead costs in the test year, it does not go far enough to ensure that KCPL's customers are protected from KCPL subsidizing its nonregulated operations.

The Staffs second objective is to reflect the dollar impact of a more reasonable and accurate General Allocation Factor than the one currently used by KCPL. While KCPL's General Allocator is an improvement over its Corp Mass Factor, it still does not adequately allocate corporate overhead costs. For example, KCPL affiliate Transource is a significant part of KCPL and Great Plains' operations. However, the General Allocator currently used by KCPL to allocate costs does not reflect any allocation of corporate overhead costs to Transource. This is a significant oversight and this consolidated adjustment is designed, in part, to correct for this oversight.

On March 30, 2015, KCPL and Great Plains filed with the Securities and Exchange Commission a Form 8-K. Included as Exhibit 99.1 to this March 30, 2015 Report is KCPL and Great Plains' March 31, 2015 Investor Presentation. A review of this document clearly shows that KCPL and Great Plains' investment in Transource Energy is currently and has been a significant part of KCPL and Great Plains' overall operations.

The third and final objective of Staff's consolidated corporate allocations adjustment is to reflect, on a going forward basis, a more accurate allocation of corporate costs among the KCPL and Great Plains affiliated entities and nonregulated operations. KCPL and Great Plains seem to have an ever increasing focus on nonregulated operations. An example of this focus is KCPL and Great Plains' formation of Transource Energy, LLC as a joint venture with AEP to pursue competitive transmission projects. KCPL and Great Plains have more recently entered the nonregulated solar energy business with KCPL Solar, Inc. As KCPL and Great Plains noted in their March 2015 Investor Presentation, the companies are continually seeking other growth opportunities such as selective future initiatives that will leverage KCPL's core strengths.

At page 8 of its March 2015 Investor Presentation, KCPL and Great Plains portray to their investors and potential investors that two out of the five components of its "Investment

Thesis" (presumably points of view/positions that make KCPL and Great Plains attractive to investors) are directly related to KCPL and Great Plains' current and future investments in nonregulated operations. These factors include "flexible investment opportunities" and future competitive investment opportunities available to Transource Energy. Clearly KCPL and Great Plains' management focus is becoming more and more on nonregulated operations and opportunities, and less and less on its regulated operations. It is important that KCPL allocate its general overhead costs consistent with this management focus. The Staff's consolidated corporate allocations adjustment attempts, in part, to accomplish this goal.

Staff Expert/Witness: Charles R. Hyneman

28. Transource Adjustments

KCPL has included in its direct revenue requirement filing two adjustments related to the Stipulation and Agreement reached by the parties and included in the Commission's Report and Order in File No. EA-2013-0098 ("Transource Case").

The first adjustment, referred to by KCPL as CS-107, reflects costs that should have been charged to Transource but were retained on the regulated books of KCPL. This adjustment is described at pages 59 and 60 of KCPL witness Ronald A. Klote's direct testimony and is labeled as KCPL adjustment CS-107 Transource Account Review. Staff has determined that, according to the Stipulation and Agreement in File No. EA-2013-0098 approved by the Commission, that it is appropriate to include this adjustment in KCPL's cost of service in this case.

The second adjustment, referred to by KCPL as CS-108, Transource CWIP/FERC Incentives, adjusts Account 565 -Transmission of Electricity by Others for the difference between KCPL's SPP load ratio share allocation of Transource Missouri's annual transmission revenue requirement (ATRR) for the Iatan-Nashua and Sibley-Nebraska City Projects and KCPL's SPP load ratio share allocation of the ATRR for the Iatan-Nashua and Sibley-Nebraska City Projects if it had been calculated utilizing KCPL's Missouri Commission-authorized ROE and capital structure, and did not include various FERC-authorized rate treatments and incentives. This adjustment is described at page 61 of KCPL witness Ronald A. Klote's direct testimony. This adjustment reflects the Stipulation and Agreement that was made by the signatories in the Transource case, which was approved by the Commission. Staff has determined that it is appropriate to include this adjustment in KCPL's cost of service in this case.

Staff Expert/Witness: Charles R. Hyneman

29. KCPL and Great Plains Officer Expense Report Adjustment

In its review of KCPL responses to Staff Data Request Nos. 0339 and 0341, Staff reviewed several Great Plains/KCPL officer expense reports. Staff found that several charges to KCPL's cost of service by Great Plains/KCPL officers appeared to be imprudent, unreasonable, excessive, and incorrectly allocated to KCPL's regulated accounts. In several previous KCPL rate cases Staff has also found problems with the prudence, excessiveness and reasonableness of KCPL and Great Plains officer expense report charges. Staff is aware of attempts by KCPL to mitigate the detriment to its customers from these types of expenses, including, in a previous rate case, KCPL making rate case adjustments to remove all officer expense report charges. In response to Staff's concerns in these prior cases KCPL appeared to implement internal control procedures designed to reduce the risk of unreasonable, imprudent and excessive officer expenses from being charged to KCPL ratepayers. It seems KCPL has either failed to continue with these internal control measures or the measures are ineffectively administered.

Staff questioned KCPL on the appropriateness of a selected small sample of officer expense report charges in Staff Data Request No. 0502. Just a few of the charges that Staff addressed in Staff Data Request No. 0502 were:

a. Thousands of dollars in iPad purchases acquired through an expense report instead of normal procurement processes where the charges were expensed instead of capitalized as required by normal accounting procedures;

b. Over $700 in meals expenses related to an employee baby shower in Kansas City;

c. A $327 dinner charge for a meeting between a KCPL employee and a Kansas City Royals official;

d. A $270 dinner charge for a KCPL employee and a former Great Plains/ KCPL Chief Executive Officer at Sullivan's Steak House in Kansas City;

e. Meal charges associated with Allconnect, Inc. non-regulated operations charged to regulated cost of service;

f. A $293 meal charge for a KCPL employee and a former KCPL employee to discuss governmental affairs at Capital Grille in Kansas City;

g. A $659 meal for a customer meeting at Capital Grille in Kansas City;

h. A $1,120 meal at Capital Grille in Kansas City for a Public Affairs and Marketing Retreat; and

i. A $530 unexplained restaurant charge for a business development meeting at Piropos Briarcliff in Kansas City.

On March 24, 2015, KCPL notified Staff that it will be making in its cost of service true-up filing an update to its adjustment CS-11 in the amount of $117,422. This update is to remove all eight Great Plains officer (not KCPL officers) expense report charges from KCPL's test year expenses. KCPL advised Staff that the expense report charges of the eight KCPL officers will not be adjusted. KCPL also indicated that the adjustment will correct a KCPL officer expense report charge that was made to KCPL's books and records that should have been made to Transource Missouri's books and records. Transource Missouri is an affiliate of KCPL.

The fact that these costs were incurred, approved, paid, and charged to accounts that would qualify for recovery from KCPL customers raises a concern regarding KCPL's other cost of service expenses that have not received the same level of scrutiny as the officer expense report charges. The officer expense report transactions occur at the highest level of authority and control of KCPL's costs. These costs would not be removed without Staff's audit. These costs were not removed from cost of service through, KCPL's own internal controls, seeking to find and remove inappropriate, excessive and imprudent officer expenses. These costs are only being removed as a result of Staff's audit of the costs that KCPL asserts are reasonable and prudent and appropriately charged to ratepayers.

This is not a new discovery by Staff, as Staff identified this practice and was assured previously by KCPL that the practice was being corrected. Information in this case provides a strong indication that KCPL did not adequately review officer expenses prior to filing this rate case, let alone address this matter before the expenses were incurred, paid, and charged to regulated expense accounts.

Because KCPL's internal controls are ineffective and KCPL has been aware of the deficiency from prior cases, Staff has decided to remove 50 percent of all KCPL and 100 percent of Great Plains officer expenses charged to test year regulated accounts in this case. This adjustment will provide a high level of the assurance that no unreasonable costs have been included in customer rates and should provide KCPL with an incentive to improve its controls to provide reasonable assurance that officer expense report charges made to KCPL's regulated accounts are reasonable, prudent, not excessive and correctly allocated without a Staff inspection.

Staff is making this adjustment because, based on past experience, KCPL has attempted to recover through its regulated utility rates, officer expenses that were excessive, unreasonable and imprudent. Staff's adjustment is necessary to prevent KCPL from doing so in this rate case. KCPL's internal controls at its highest level have failed to provide any reasonable assurance that KCPL have removed such charges from being included in its utility rates without Staff oversight. Staff's rate case audit will detect a portion of KCPL's executives' inappropriate charges but cannot be relied upon to provide reasonable assurance that all such costs have been identified and removed.

The risk that KCPL's test year books and records contain significant amounts of excessive, unreasonable, and imprudent charges is high given the apparent practice at the top of KCPL's structure of authority and responsibility. Staff's concern is that if a company's officers will act excessively, inappropriately and imprudently when incurring costs that are charged to regulated ratepayers, then these same officers will also be tolerant of similar activities throughout the other levels of the company. In its direct cost of service filing Staff will remove the $117,422 amount that KCPL calculated as Great Plains officer test year expenses. Any additional officer expense charges will be reflected in Staff's consolidated affiliate transaction/corporate allocation adjustment described below. Staff's adjustment to remove 50 percent of KCPL's officer expenses is reflected in the dollar value of Staff's consolidated corporate allocations adjustment. This adjustment is discussed in a different section of this report.

Staff Expert/Witness: Charles R. Hyneman

X. Depreciation

A. Plant-In-Service Review

Staff visited KCPL's La Cygne facility on February 23, 2015, to observe operations and installation of the Air Quality Control System (AQCS) on Unit 2. During this time, KCPL was in the process of calibrating the air quality instrumentation used in measuring various emissions exhausting through Stack Number 2. KCPL personnel and Staff also reviewed project control documents during the visit and project status completion and budgetary items were generally reviewed as well. Discussion during the visit also included an unplanned forty-five (45) day outage due to a crack found in Unit 2's 40 year-old General Electric turbine.

Staff visited KCPL's Montrose facility on February 25, 2015, in order to audit the plant-in-service records retained by KCPL. Staff, via supplemental Data Request No. 0176.1, requested that KCPL locate thirty (30) plant-in-service records. These plant records were chosen by the random number generation method. KCPL was able to locate twenty-eight (28) of the thirty (30) randomly chosen plant-in-service records. Of the two records (plant-in-service items) that were unable to be located by KCPL, one of the records had since been retired because the plant-in-service records provided to Staff were a "snapshot" of KCPL's records as of December 31, 2013. (In essence, the item had been retired post December 31, 2013; retired in March of 2014). The other item that could not be located was an engineering workstation that was upgraded in 2004; however, the previous 1993 vintage was not retired from the Accounting records. Staff will continue to monitor the plant-in-service records and periodically audit other facilities, as necessary, to ensure the plant-in-service records are maintained appropriately by the KCPL.

B. Staff's Review of KCPL's Submitted Depreciation Study

Staff continues to review KCPL's depreciation study sponsored by its witness John J. Spanos of the consulting firm Gannett Fleming. Staff has requested and received Mr. Spanos' work papers and further information and clarification on specific questions related to the depreciation study. Staff has reviewed the historical retirement, cost of removal, and salvage data files; conducted a depreciation analysis using Staff's version of the Gannett Fleming depreciation software; and verified the depreciation study results submitted by Mr. Spanos. While Staff agrees with the analysis methods and findings presented by Mr. Spanos, Staff's recommended depreciation rates differ from the depreciation rates proposed by Mr. Spanos. This difference is a result of Staff's removal of a component of net salvage (future cost of removal for electric generating facility retirements), from the current depreciation accruals.

C. Overall Accumulated Depreciation Reserves

Based on the depreciation study balances for December 31, 2013, for the $4.4 billion total Missouri jurisdictional plant-in-service $1.9 billion has been accrued in depreciation reserves. Staff estimates that approximately $200 million of this $1.9 billion is allocated to future cost of removal. Staff's estimate of over- (or under-) accrual of depreciation for all plant accounts found a positive balance (over-accrual) of approximately $500 million. Of this $500 million, almost all, $480 million, was found in Production Plant accounts, with only $20 million for all Transmission, Distribution and General plant accounts.

This over-accrual of depreciation reserves has been addressed within KCPL's proposed depreciation rates and similarly within Staff's recommended depreciation rates. The depreciation rates proposed by KCPL, and those recommended by Staff, use a remaining life method that adjusts the depreciation rate for each account to decrease or increase the accrual rate depending on the rate of accrual needed over the remaining life of the asset. The result for both KCPL's proposal and Staff's recommendation is a reduction of approximately $20 million per year in depreciation expense aimed at reducing the $500 million over-accrual mentioned above.

The over-accrual is a result of prior depreciation practices, ordered depreciation rates, and settlement positions that included KCPL, Staff, and other involved parties. This over accrual does provide a benefit to current ratepayers in the form of a $500 million reduced rate base and an estimated $20 million annual reduction of depreciation expense. In such manner, customers are receiving 'benefit' of their $500 million dollar depreciation payments.

Over-accrual of depreciation simply indicates that the current accumulated reserve contains a larger number of dollars than an estimate of the current amount of original cost dollars that have been consumed by normal wear and obsolescence. About $83 million of this over-accrual is related to an incident and resultant insurance settlement at the Hawthorn facility, where the insurance settlement was recorded to reserves. Another $185 million is related to a period of Credit Metrics regulation that was put into effect during the construction of Iatan Unit 2 to increase KCPL's cash flow through regulatory amortizations directed towards keeping KCPL's credit rating from being reduced. The dollars collected for these amortizations, what is referred to as an Additional Amortizations, was transferred to the Iatan Unit 2 plant account reserves after Iatan Unit 2 was placed-in-service as part of a Stipulation reached in Case No. ER-2010-0355 (see Regulatory Plan Additional Amortizations section of this Cost of Service Report). The remaining $232 million is mainly due to equipment lasting longer than originally expected when the depreciation rates were ordered. No intentional corrective action was taken to recover general over accruals in recent history. The introduction of the use of a remaining life method to compute depreciation rates in this rate case is intended to address over and under accruals in all plant accounts on a going forward basis.

D. Estimation of Future Retirement Cost of Removal of Electric Generating Units

KCPL witness Christopher Rogers submitted Direct Testimony containing a decommissioning study for all KCPL's electric generating equipment, with the exception of the Wolf Creek Nuclear Generating Facility which has a separate decommissioning study and decommissioning funding. Mr. Roger's decommissioning study estimated the expected future cost to retire and to dismantle KCPL's electrical generation equipment as two principal phases. Those two separate phases are the retirement phase and the dismantlement phase. For each production unit, Mr. Rogers provided a separate cost estimate for each distinct phase.

The retirement phase is the shutdown or closure and removal from service of a generating unit or facility, and includes disconnection, de-energization, cleanout, and securing of the units to render them safe. Retirement triggers unavoidable costs for compliance with the mandatory provisions of the various plants' permits and with the specific requirements of state and federal regulations for the closure of systems such as coal stockpile areas, coal ash landfills, waste treatment lagoons, the removal and remediation of fuel-oil tanks, and the reclamation of river water intakes.

The dismantlement phase is the orderly demolition of a production unit in a controlled and safe manner so as to preserve the scrap value of reclaimed materials while appropriately protecting the workers and the environment. Scrap values in Mr. Rogers' report were developed from current average index prices, and were netted out against dismantlement costs to produce net terminal costs for each unit.

Mr. Roger's study is not dependent on any projected retirement date because he presents the retirement and dismantlement cost in 2014 dollars as if the retirement and dismantlement were to have occurred in 2014 for each production unit.

E. Depreciation Expense - Terminal Net Salvage

Regulatory depreciation expense accruals presented in Mr. Spanos' direct testimony include two basic components: one of the components addresses original cost, and the other component addresses net salvage. Net salvage is gross salvage minus the cost of removal. In this case, KCPL recommends that net salvage be further differentiated consisting of two parts, interim and terminal cost of removal and salvage.

In this report, the term interim net salvage is associated with the removal from service of units of property from a works or system where the works or system continues to provide utility service. Examples of interim net salvage are the replacement of a pump, transformer, utility pole, or turbine within a works or system that is expected to continue to operate and continue to provide utility service. Whereas, terminal net salvage is used exclusively for net salvage associated with the removal from service of an entire works or system such as an electric generating unit where all of the equipment associated with that works or system is removed from service simultaneously when the unit or system is shutdown. Removal from service of a works or system is the retirement of all associated units of property within the works or system regardless of age or working condition. Any account activity occurring after the works or system is shutdown to make safe, decontaminate, remove for salvage, or dismantle the works or system is defined as terminal net salvage.

Also within this report, terminal net salvage is further differentiated into two parts or costs, a retirement phase cost and a dismantlement phase cost. The definition of retirement cost versus dismantlement costs are defined above in the summary of Mr. Rogers' decommissioning study.

The derivation of the existing ordered depreciation rates for KCPL did not include a differentiation of net salvage into interim and terminal components, or the retirement phase versus a dismantlement phase for terminal net salvage, for production equipment other than for Wolf Creek, KCPL's nuclear generating facility. Therefore the current ordered depreciation rates for all KCPL plant accounts include the accrual of net salvage for 100% of the plant original cost, with no differentiation between interim and terminal net salvage, with the exception of Wolf Creek. The Wolf Creek Nuclear Generation unit has a separate decommissioning fund and, therefore, neither KCPL's proposal nor Staff's recommended depreciation rates for Wolf Creek include accrual of terminal net salvage.

KCPL's proposed depreciation rates and Staff's recommended depreciation rates are different because the amounts of terminal net salvage included for Production Plant accounts are not consistent. KCPL's witness Spanos has proposed depreciation rates for steam, wind, and combustion turbine electrical production equipment that includes the accrual of interim net salvage and the retirement portion of terminal net salvage, but not the dismantlement portion of terminal net salvage. Staff's depreciation rate recommendation for steam, wind, and combustion turbine electrical production equipment includes accrual for interim net salvage only, and does not include an accrual for any terminal net salvage (both the retirement and dismantlement portions of terminal net salvage were removed by Staff when determining its proposed depreciation rates).

Staff's reasons for recommending that terminal net salvage not be allowed for production plant are:

1. Staff's review found an over accrual of deprecation in the Production Plant accounts of about $480 million dollars. Even though Staff's deprecation rate recommendation provides for approximately a $20 million per year reduction in this over-accrual, Staff is of the opinion that there will remain sufficient accumulated reserves to address foreseeable future terminal cost of removal requirements and there is no need to accumulate more at this time.

2. With respect to other Missouri regulated electric utilities, the Commission's *Report and Order* for The Empire District Electric Company ("Empire"), Case No. ER-2004-0570, dated March 10, 2005, made a distinction between interim and terminal net salvage. The Commission stated on page 53 of the order in that case that "the Commission will not allow the accrual of any amount for Terminal Net Salvage of Production Plants." In Case No. ER-2010-0036, Ameren Missouri's witness Spanos introduced a procedure in his direct testimony depreciation study for Ameren Missouri's rate case that examined each production plant facility to estimate expected future needs for interim versus terminal net salvage for each account and applied a weighted average correction to eliminate terminal net salvage. The Commission's *Report and Order* for Ameren Missouri's 2010 case directed that the depreciation rates derived from Mr. Spanos' study be approved (with the exception of the Commission's extension of the retirement date for the Meramec plant by five years).

F. Projected Production Unit Retirement Dates

In order to compute and differentiate interim versus terminal net salvage for a plant account specific to an individual production unit, a retirement date needs to be specified such that remaining life in years for the dollars in the account may be determined. The depreciation studies conducted by KCPL and Staff were conducted using only interim retirement historical data to determine an appropriate survivor curve (Iowa Curve) that matches the historical retirement rate for interim retirements. The survivor curve, in conjunction with the expected remaining life, was used to determine the percentage of original cost of plant-in-service that is expected to be retired as interim retirements versus the amount that will be retired as terminal retirements. These percentages are applied to the total estimated net salvage (including estimated future cost of removal) to determine the amounts in dollars expected to be required for interim and terminal net salvage. The depreciation study provides an estimate for interim net salvage for all plant accounts. The decommissioning study, filed by KCPL's witness Christopher Rogers, was used to estimate a terminal net salvage component for production plant accounts. The inclusion of terminal net salvage in depreciation rates by KCPL witness Rogers, allows an amount of dollars to be collected in depreciation expense over the expected remaining life for interim and/or terminal net salvage as desired. However, Staff did not include terminal net salvage in its proposed depreciation rates developed in this case.

The projected retirement dates for production plants proposed by KCPL were adopted by Staff and incorporated into Staff's depreciation rate recommendations. A summary of the projected retirement dates used are shown in the table below. However, Staff recognizes that any actual future retirement date of a production unit is in no way defined by or a function of an estimated date used to compute a depreciation rate for this rate case.

Steam Production Plant	In Service Year	Probable Retirement Year	Expected Life, Years
Hawthorn Unit 5	1969/2001	2055	86/54
Hawthorn Unit 9	1955/2000	2045	90/45
Montrose Unit 1	1958	2016	58
Montrose Unit 2	1960	2021	61
Montrose Unit 3	1964	2021	57
latan Unit 1	1980	2040	60
LaCygne Unit 1	1973	2040	67
LaCygne Unit 2	1977	2040	63
Iatan Unit 2	2010	2070	60
Nuclear Production			
Wolf Creek	1985	2045	60

G. Staff's Recommended Depreciation Rates

Staff recommends the Commission order KCPL to use the depreciation rates shown in Appendix 3, Schedule DAM-1 for all of KCPL's plant accounts. Schedule DAM-1 shows, in addition to Staff's recommended depreciation rates for each plant account: 1) probable retirement date, 2) the expected remaining life of the dollars in the account as of December 31, 2013, 3) the net salvage rate, 4) statistically-determined retirement rate survivor curve, 5) accruals used in computations, and 6) the resultant composite depreciation rate.

H. Staff's Depreciation Summary

The table below shows the resultant estimated annual depreciation accruals (expense) between the following three sets of depreciation rates: 1) KCPL's currently ordered depreciation rates, 2) KCPL's proposed depreciation rates, and 3) Staff's recommended depreciation rates. Staff used Missouri jurisdictional plant-in-service balances as of December 31, 2014 to derive these depreciation expense comparisons.

Annual Depreciation Expense Comparison, December 31, 2014

Currently Ordered	KCPL Proposed	Staff Recommended
$111.3 million	$107.4 million	$104.9 Million

The method of net salvage computation is the main variable between the three cases shown. The difference in the net salvage variable can be explained as follows:

1. Current KCPL depreciation rates assume the production plants continue to be updated and operate with no terminal retirement date and that 100% of plant-in-service will incur only as interim net salvage;
2. KCPL's proposal defines a retirement date for each production plant and removes part of the terminal net salvage;
3. Staff's recommendation defines a retirement date for each production plant and removes all terminal net salvage.

Staff's recommended depreciation rates are shown in Appendix 3, Schedule DAM-1.

I. Accumulated Future Cost of Removal

Depreciation expense includes accruals for future cost of removal. Staff requested that KCPL provide, by plant account, the dollar amount of net salvage (future cost of removal, interim and terminal) included in the depreciation reserves. KCPL reported a *theoretical estimated* amount of $189 million of cost of removal for all plant accounts calculated as of December 31, 2013. KCPL's response included the following statement indicating that the amounts they provided were not realistic.

> These amounts assume the development of the book reserve by account utilizing the same parameters from the beginning of time. The proposed parameters would not be appropriate since the accumulated reserve has not been based at any time on these parameters.

Staff agrees that the $189 million amount is a theoretical amount based on unrealistic assumptions. KCPL has a similar regulatory history as Ameren Missouri in that both are regulated by the same Commission such that depreciation accrual methods should have a similar history, and therefore a similar percentage of net salvage in reserves. In Ameren Missouri's rate case, Case No. ER-2014-0258, The Financial Accounting Standards Board Standard, Statement of Financial Accounting Standards (SFAS) Number 143, has been followed and Ameren Missouri's reported amount for net salvage contained in depreciation reserves is 12.0% of total depreciation reserves[76]. KCPL reports $1.876 billion in total depreciation reserves for December 31, 2013. Using Ameren Missouri's 12.0% of depreciation reserves as net salvage, applying that percentage to KCPL's $1.876 billion of total reserves results in $225 million of estimated net salvage. Using these two sources as a guide, Staff estimates that KCPL has approximately $200 million of depreciation reserves allocated to future cost of removal.

Staff believes that within SFAS Number 143, Asset Retirement Obligations, electric utilities are directed to track net salvage amounts contained in accumulated depreciation starting in 2003. Staff believes KCPL should have estimated the amount of net salvage contained in accumulated depreciation as of December 31, 2003, and continued to track this amount in compliance with the Financial Accounting Standards Board accounting standard SFAS Number

[76] The Staff Cost of Service Report for Ameren Missouri's Case No. ER-2014-0258 filed December 5, 2014 states on page 8 line 28, "Ameren Missouri has already accrued approximately $800 million in accumulated depreciation reserves for future cost of removal." The accompanying Staff Accounting Schedules filed this same date show total depreciation reserves of $6.8 Billion. A simple division yields 12%.

143 – Accounting for Asset Retirement Obligations, using the following method for each plant account:

2003 Starting Estimate = [Book Reserve * {(- *Net Salvage %) / (100% - Net Salvage %)}]*.

Each year subsequent to 2003, net salvage accruals and gross salvage are added and removal costs are subtracted from the amount determined as of December 31, 2003.

Staff recommends the Commission order KCPL to keep records of the amount of net salvage contained in depreciation reserves and to follow the SFAS 143 guidelines.

J. Under Accrual of Depreciation for AMR Customer Meters

A replacement program has been initiated by KCPL for the replacement AMR type meters with AMI type meters. KCPL created a new plant subaccount 370.002 for the new AMI meters. This action results in a stranded deficit of accumulated depreciation reserves, (unrecovered original cost), of approximately $8.7 million in AMR meters account 370.001 as the ARM meters are retired due to obsolescence. KCPL has proposed an amortization of approximately $8.7 million over 10 years to recover this amount in customer rates. Staff recommends an alternate method be used to address this under recovered amount. Customers have previously provided dollars in the form of amortizations that have been recorded to depreciation expense in the over accrual of production plant. Staff recommends transferring $8.7 million of the over accrual in the Distribution accounts 364 to the AMR meters account reserves to address the under recovery resulting from obsolescence of the AMR meters. This transfer of reserves also results in an increase in Staff's recommended depreciation rate for account 364 from 3.18% to 3.37%.

K. Staff Recommendations

1. Staff's recommends the Commission order the depreciation rates for KCPL electric operations presented in Appendix 3, Schedule DAM-1 that have been determined on the basis of incorporating an estimated retirement date for production units and do not provide for the accrual of terminal net salvage in depreciation expense.

2. Staff recommends the Commission order KCPL to keep records of the amount of net salvage contained in depreciation reserves and to follow the SFAS 143 guidelines.

3. Staff recommends the Commission order KCPL to transfer depreciation reserves from distribution account 364 to offset an under recovery in the AMR Meters account 370.002.

Staff Expert/Witness: Derick A. Miles

XI. Regulatory Plan Additional Amortizations

The Experimental Alternative Regulatory Plan Additional Amortizations were authorized by the Commission in Case No. EO-2005-0329. The Commission approved a unique regulatory approach presented in a Stipulation and Agreement signed by KCPL and numerous parties, including The Office of the Public Counsel and Staff, which allowed KCPL certain accommodations to traditional ratemaking for pursuing what KCPL referred to as its "Comprehensive Energy Plan". This experimental alternative regulatory plan (the "Regulatory Plan") resulted, among other things, in fostering the construction of Iatan Unit 2. KCPL completed construction of this 850 megawatt pulverized coal-fired supercritical steam electricity generating unit which KCPL declared met the in-service criteria of the Regulatory Plan on August 26, 2010. Iatan Unit 2 is adjoins the original Iatan Unit 1 KCPL completed building in May 1980.

In the Regulatory Plan, KCPL also committed to make significant environmental upgrades to La Cygne Unit 1 and Iatan Unit 1, and to construct 100 megawatts of wind generation. KCPL satisfied its wind build commitment with its Spearville Wind Farm in western Kansas, which was included in its rate base when setting rates in 2007 in Case No. ER-2006-0314. The first phase of the environmental upgrades at La Cygne Unit 1 was completed in 2007. KCPL's Missouri jurisdictional portion of the La Cygne Unit I investment was included in KCPL's rate base in KCPL's 2007 rate case, Case No. ER-2007-0291. KCPL completed the extensive environmental upgrades to Iatan Unit 1 in the first quarter of 2009. The Missouri jurisdictional part of KCPL's investment in those upgrades was primarily included in KCPL's rate base in KCPL's 2009 rate case (Case No. ER-2009-0089). KCPL completed Iatan Unit 2 in August 2010, and the costs for this units were included in KCPL's 2010 rate case (Case No. ER-2010-0355).

The Additional Amortizations were an accommodation to traditional ratemaking to assist KCPL to maintain certain financial ratios. KCPL was permitted to calculate its revenue requirement using these cash flow ratios or financial benchmarks in order to provide KCPL with sufficient cash (earnings) to maintain certain investment grade financial measures. In the Regulatory Plan, the signatory parties agreed to allow KCPL to include amounts in its rate cases referred to as "additional amortizations" which had the effect of increasing KCPL's cash flow through increased retail revenues. These additional amortizations were determined using a model set out in the Regulatory Plan.

The additional amortizations were an addition to the cost of service expenses, and caused the rate increases resulting from each of the affected rate cases to be greater than the amount of the increase determined necessary from a traditional cost of service calculation.

The additional amortizations resulting from the 2006, 2007 and 2009 KCPL rate cases were cumulatively reflected in the revenue requirement calculation for KCPL. The rate cases and Commission-ordered additional amortizations in each follow:

Case No.	Additional Amortizations Ordered	Cumulative Additional Amortizations
Case No. ER-2006-0314	$21.7 Million	$21.7 Million
Case No. ER-2007-0291	$10.7 Million	$32.4 Million
Case No. ER-2009-0089	$10.0 Million	$42.4 Million

The accumulated additional amortizations amounts from the 2006, 2007 and 2009 rate cases are included in Staff's cost of service determination for KCPL as an offset (reduction) to plant in service through the accumulated depreciation reserve. These amounts are reflected in Schedule 6—Depreciation Reserve.

In the 2010 KCPL rate case (Case No. ER-2010-0355), several parties, including KCPL and Staff, agreed to the on-going treatment for the additional amortizations in future rate cases. The Commission approved a Non Unanimous Stipulation and Agreement Regarding Depreciation and Accumulated Additional Amortizations that authorized the transfer of $146.7 million of accumulated additional amortizations to Accumulated Depreciation Reserve-Account 399 through May 3, 2011 – the date rates changed in Case No. ER-2010-0355. Since each state (Kansas and Missouri) had separate regulatory plans and collected the additional amortizations from each states' customers separately, all the additional amortizations are identified on a Missouri jurisdictional basis. The amounts of the three additional amortizations from the three rate previous cases as of May 3, 2011, based on the Stipulation are:

ADDITIONAL AMORTIZATIONS RESULTING FROM REGULATORY PLAN— Case No. EO-2005-0329—Accumulated Reserve Amounts-Missouri Jurisdictional Basis		
Rate Case		**May 3, 2011**
Case No. ER-2006-0314		$94,120,782
Case No. ER-2007-0291		35,834,231
Case No. ER-2009-0089		16,748,858
TOTAL		**$146,703,871**

Source: KCPL's Accumulated Depreciation Reserve Account 399—page 6. paragraph 7 of 2011 Stipulation

Aside from the additional amortizations from KCPL's Regulatory Plan, KCPL also had an additional amortization from a Stipulation and Agreement the Commission approved on July 3, 1996 in Case No. EO-94-199. The Stipulation the Commission approved included a $3.5 million additional annual amortization. This additional amortization continued resulting in a total accumulation of $36,674,731 booked in KCPL's Accumulated Depreciation Reserve-- Account 399 when it ended on December 31, 2006.

The totals of all these accumulated additional amortizations from the Regulatory Plan-- Case No. EO-2005-0329 and from Case No. EO-94-199 - as of May 3, 2011, are shown as Missouri Jurisdictional amounts in the table below:

	Total Missouri Jurisdictional Additional Amortizations
Case No.	**May 3, 2011**
Case No. EO-2005-0329	$146,703, 871
Case No. EO-94-199	36,674,731
TOTAL	**$183,378,602**

Source: KCPL's Accumulated Depreciation Reserve Account 399—page 6, paragraph 7 of 2011 Stipulation.

The total additional amortizations of approximately $183.4 million are treated in this case in a consistent manner with the agreement approved in Case No. ER-2010-0355. The accumulated additional amortizations are specifically identified in the plant accounting record system for depreciation reserve. The additional amortizations were distributed to Iatan Unit 2 Uniform System of Accounts-- account numbers 311, 312, 314, 315 and 316 --as specified in the agreement in the 2010 KCPL rate case as follows:

STIPULATION IN CASE NO. ER-2010-0355 FOR ADDITIONAL AMORTIZATIONS RESULTING FROM REGULATORY PLAN— Case No. EO-2005-0329—Accumulated Reserve Amounts-Missouri Jurisdictional Basis		
Account 311.070		**$19,240,688**
Account 312.070		**137,897,545**
Account 314.070		**19,135,918**
Account 315.070		**6,399,672**
Account 316.070		**704,779**
TOTAL		**$183,378,602**

Source: Staff EMS Run—Schedule 6—Accumulated Depreciation Reserve for Iatan Unit 2 Plant

Transferring the Missouri jurisdictional additional amortization amounts to Iatan Unit 2 depreciation reserve reduces KCPL's rate base for amounts collected from its customers during the time of the Regulatory Plan. The agreement ensured that the additional amortizations collected by Missouri customers are used to the benefit of customer rates through the reduction of rate base throughout the life of Iatan Unit 2. No return "on" investment or "of" the investment through depreciation is afforded the Additional Amortization amounts. As such, KCPL receives no return on investment through the rate base or return of the investment through depreciation expense for the $183.4 million of Additional Amortizations for Iatan Unit 2 plant throughout its life.

Staff Expert/Witness: Cary G. Featherstone

XII. Current and Deferred Income Tax

A. Current Income Tax

Current income tax for this case has been calculated by Staff generally consistent with the methodology used in KCPL's last rate case, Case No. ER-2014-0370. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different from the timing required by the Internal Revenue Service (IRS) in determining taxable income.

Current income tax reflects timing differences consistent with the timing required by the tax regulations. The tax timing differences used in calculating taxable income for computing current income tax for KCPL are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

50% Meals and Entertainment Disallowance

Book Nuclear Fuel Amortization

Book Amortization Expense

Subtractions from Operating Income:

Interest Expense - Weighted Cost of Debt X Rate Base

IRS Accelerated Tax Depreciation

IRS Nuclear Fuel Amortization

IRS Tax Return Plant Amortization

Employee 401k ESOP Deduction

Subtractions Federal Income Tax Credit:

Wind Production Tax Credit

Research and Development Tax Credit

Fuels Tax Credit

Staff Expert/Witness: Keith Majors

B. Kansas City Earnings Tax

Additionally, Staff normalized the Kansas City, Missouri earnings tax (KCET) in this rate case. This is included in the revenue requirement calculation as Adjustment E-255.1. Staff included $0 for earnings taxes, as KCPL will pay $0 for 2014.

Staff Expert/Witness: Keith Majors

C. Deferred Income Tax Expense

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for current income tax as the result of the Internal Revenue Code (IRC), the timing difference is given flow-through treatment. When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given normalization treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of normalizing tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated tax depreciation.

Staff Expert/Witness: Keith Majors

D. Accumulated Deferred Income Taxes (ADIT)

1. <u>Plant Related</u>

KCPL's deferred income tax reserve represents, in effect, a prepayment of income taxes by KCPL's customers. As an example, because KCPL is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is significantly higher than depreciation expense used for financial reporting (book purposes) and for ratemaking purposes. This results in what is referred to as book-tax timing difference, and creates a deferral, or future liability of income taxes, to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to KCPL. Therefore, KCPL's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the company. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base. Besides accelerated depreciation, Staff has also included deferred taxes specifically associated with the rate base inclusion of the pension liability.

The rate base impact of ADIT is included in Schedule 2 – Rate Base in Staff's accounting schedules.

Prior to the 1986 Tax Reform Act, flow-through treatment (current year deduction) was used for Missouri utilities unless the utility could demonstrate the need for additional cash flow to meet interest coverage ratios. It is Staff's understanding that KCPL received normalization treatment in rate cases prior to 1986 based upon a need for additional cash flow during significant construction activity related to new generation facilities.

Timing differences which were reflected as a tax deduction in the current year, for current income tax to the IRS, were deferred (normalized) for ratemaking purposes. The tax deduction is reflected in rates by amortizing the deferred tax balance over the depreciable life of the property. Staff's income tax calculation for KCPL, in this current case, reflects the amortization of prior timing differences which were normalized in prior rate cases. Adjustment E-265.1 reflects an annual amortization of deferred taxes resulting from normalization treatment in prior cases.

The 1986 Tax Reform Act reduced the federal tax rate for corporations from 46% to 34%. As a result all deferred taxes, previously reflected in rates, based upon an assumed 46% tax rate, were overstated. The IRS allowed a regulated utility to flow back (amortize) to ratepayers the excess deferred taxes over the approximate depreciable book life of the property. Staff's income tax calculation for KCPL in this case reflects an amortization of excess deferred taxes resulting from the reduction in the federal tax rate in 1986. Adjustment E-266.1 reflects an annual amortization of the excess deferred taxes resulting from the reduction in the federal tax rate.

Prior to the 1986 Tax Reform Act, a utility received a permanent tax credit for investing in new capital additions. For ratemaking purposes, the IRS allowed the utility to amortize (flow back to ratepayers) the investment tax credit over the approximate depreciable book life of the related property. Adjustment E-264.1 reflects an annual amortization of the deferred investment tax credit.

2. ADIT on Construction Work In Progress (CWIP)

KCPL records ADIT that is associated with the CWIP reflected on its books and records. This ADIT represents a free source of capital funds available for use by the utility before the construction project is completed and included in plant-in-service. CWIP is excluded from the rate base on which KCPL earns a return in the ratemaking process. Although CWIP is not included in rate base, KCPL is allowed to earn an Allowance for Funds Used During Construction ("AFUDC") before the property under construction is added to rate base. AFUDC is accrued during the construction of the asset and included in rate base when the plant is placed into service. The amount of AFUDC is included in depreciation and rate base over the life of the plant. For the calculation of AFUDC, there is no consideration for ADIT as a reduction to the base on which it is calculated; the AFUDC is calculated on the "gross" amount, with no consideration of ADIT.

Utilities have argued that it is inappropriate to reduce rate base for ADIT associated with CWIP balances, when the CWIP amounts are not included in rate base. However, the Commission has found to the contrary recently. Reducing rate base by the amount of ADIT on CWIP was an issue decided by the Commission in the recent Ameren Missouri general rate case, Case No. ER-2012-0166. On page 30 of its *Report and Order* in that case, the Commission stated why this treatment is appropriate:

> In other words, failure to recognize the CWIP-related ADIT balance in the company's rate base will overstate the companies AFUDC costs and future rate base, essentially allowing the company to earn AFUDC and a return on capital supplied by ratepayers...
>
> ...As fully explained in the findings of fact, Ameren Missouri must include CWIP-related ADIT balances as an offset to rate base to avoid overstating AFUDC and future rate base, to the detriment of both current and future ratepayers.

Therefore, Staff recommends the amount of ADIT on CWIP as of December 31, 2014, be used as an additional reduction to KCPL's rate base, similar to other amounts of ADIT. Because a significant portion of this ADIT is related to the La Cygne construction project, Staff will update this offset to rate base in the May 31, 2014 true-up.

The amount of ADIT on CWIP is listed as a reduction to rate base on Schedule 2 – Rate Base, in Staff's accounting schedules.

Staff Expert/Witness: Keith Majors

XIII. Jurisdictional Allocations

The Missouri Public Service Commission ("Commission") sets cost-of-service based rates for the utility's Missouri retail customers; however, not all the costs a utility incurs are associated with its provision of service to its Missouri retail customers. KCPL has both retail and wholesale customers in both Missouri and Kansas. Wholesale sales, under the jurisdiction of Federal Energy Regulatory Commission ("FERC"), retail sales in Missouri, and retail sales in Kansas are described as sales in three separate "jurisdictions." Some costs to serve a particular jurisdiction may be directly assignable to that jurisdiction; however, other costs may not. Costs that are not directly assignable to a particular jurisdiction are allocated among the various jurisdictions. Costs that vary with energy consumption, i.e. "variable costs"-are denoted as "energy-related". Costs that do not vary with energy consumption, i.e. "fixed costs"-are denoted as "demand-related". Different allocation factors are developed and utilized for each.

Jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel and purchased power, are more appropriate to allocate on the basis of energy consumption. In this Case, Staff calculated jurisdictional allocation factors for demand and energy to allocate KCPL's demand-related (fixed) costs and energy-related (variable) costs between the three applicable jurisdictions: Missouri retail jurisdiction, Kansas retail jurisdiction, and the wholesale jurisdiction. The particular jurisdictional allocation factor applied depends upon the nature of the cost being allocated among the associated jurisdictions.

Staff Expert/Witness: Alan J. Bax

A. Methodology

1. Demand Allocation Factor

Demand refers to the rate at which electric energy is delivered to a system to match the energy requirements of its customers, generally expressed in kilowatts (kWs) or megawatts (MWs), either at an instant in time or averaged over a designated interval of time. System peak demand is the largest electric requirement occurring within a specified period of time (e.g., hour, day, month, season, and year) on a utility's system. Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands, plus required reserves, the contribution of each of the three individual jurisdictions coincident to these system peak demands is the appropriate basis on which to allocate the costs of these facilities.

Thus, the term coincident peak (CP) refers to the load, generally in kWs or MWs, in each of the jurisdictions that coincide with KCPL's overall system peak recorded for the time period used in the corresponding analyses.

Staff utilized a 4 CP method - based on the monthly seasonal coincident peaks of the four summer months in calendar year 2014 to determine the demand allocation factors, the same method that the Commission ordered in Case No. ER-2006-0314, and which both KCPL and Staff have used in each subsequent KCPL rate case (Case Nos. ER-2007-0291, ER-2009-0089, ER-2010-0355 and ER-2012-0174). The 4 CP method is appropriate for a utility such as KCPL that experiences dominant demands in the four summer months (June through September) relative to the demands in the other eight months of a year. A utility that experiences a needle peak in a particular month may utilize the 1 CP method, or a utility that experiences comparatively similar hourly peaks in both winter and summer months might employ the 12 CP method. In analyzing the monthly demands for the for the summer months of calendar year 2014, which lie within the update period utilized by Staff in the current rate case, these demands are consistent with the monthly demands in the analyzed periods associated with these aforementioned rate cases.

Staff determined the demand allocation factor for each jurisdiction using the following process:

a. Identify KCPL's peak hourly load in each month for the four - month period June 2014 through September 2014 and sum the hourly peak loads.

b. Sum the particular jurisdiction's corresponding loads for the hours identified in a. above.

c. Divide b. above by a. above.

The result is the allocation factor for each jurisdiction:

- Missouri Retail Jurisdiction: 0.5317
- Kansas Retail Jurisdiction: 0.4659
- Wholesale Jurisdiction: 0.0024
- Total: 1.0000

2. Energy Allocation Factor

Variable expenses, such as fuel and purchased power, are allocated to the jurisdictions based on energy consumption. The energy allocation factor for each jurisdiction is the ratio of the total kWh used by the particular jurisdiction in the 12-month period ending March 2014, to KCPL's total system kWh usage during the test year. Staff applied adjustments to these kWhs to account for losses, weather, certain annualizations and customer growth. Staff witness Seoung Joun Won, Ph.D., provided the weather adjustment. Staff witnesses Robin Kliethermes and Keith Majors provided the adjustments for annualizations and customer growth respectively. Staff has calculated the following energy allocation factors for each jurisdiction:

- Missouri Retail Operations: 0.5723
- Kansas Retail Operations: 0.4250
- Wholesale Operations: 0.0027
- Total: 1.0000

These jurisdictional demand and energy allocation factors were provided to Staff witness Cary G. Featherstone to allocate related costs to the Missouri retail jurisdiction.

Staff Expert/Witness: Alan J. Bax

B. Application

As stated above, KCPL operates within two state jurisdictions, Missouri and Kansas, and in the wholesale jurisdiction regulated by the FERC. Therefore, it is necessary to identify, then allocate and/or assign, KCPL's specific investments and costs among these three jurisdictions (Missouri Retail, Kansas Retail and Wholesale). To identify KCPL's revenue requirement, Staff must develop KCPL's cost of service for its Missouri retail jurisdiction. To do that KCPL's plant investments and costs in its income statement must be appropriately assigned or allocated to the Missouri retail jurisdiction.

To develop KCPL's cost of service for its Missouri retail jurisdiction, Staff began with KCPL's records kept in accordance with FERC accounting requirements per Commission rule. Where these records reflected costs or investments that KCPL incurred solely to serve the Missouri retail jurisdiction, Staff directly assigned those costs or investments to KCPL's Missouri jurisdictional cost of service. However, when it was not appropriate to directly assign costs or investments, Staff allocated those costs using either a demand or energy allocation factor, depending upon whether the investment or cost was incurred more due to demand or more due to energy.

KCPL uses its generation and transmission facilities to produce and transport electricity to its Missouri retail customers, Kansas retail customers and wholesale customers (FERC jurisdiction). Because these facilities are primarily sized to meet demand, Staff allocated KCPL's costs and investments in these facilities, as well as the related depreciation reserve accounts, to the two state and one federal jurisdiction on the basis of demand, i.e., with demand allocators. Since KCPL is a four summer month peaking utility, Staff used the 4 coincident peak ("4 CP") method to develop the Missouri retail jurisdiction, Kansas retail jurisdiction and wholesale jurisdiction demand allocators. Staff has consistently used the 4 CP method to develop the KCPL demand allocators since KCPL's 1985 Wolf Creek rate case, including each of the four KCPL Regulatory Plan rate cases filed prior to this rate case.

The Commission has approved the use of the 4 CP method to allocate joint investment costs and expenses since the 1985 Wolf Creek rate case. The Commission stated in KCPL's 2006 rate case its reason for using the 4 CP allocation method (page 74, Case No. ER-2006-0314):

> KCPL operates in both Kansas and Missouri. Instead of maintaining separate systems, KCPL's sole system serves both jurisdictions. To set just and reasonable rates for each jurisdiction requires allocating various generation and transmission capital costs property between these states. KCPL and other parties disagree over which coincident peak method to use to allocate those costs.
>
> Coincident peak refers to the load of each jurisdiction that coincides with the hour of a utility's overall system peak. KCPL asserts that its operating

> and capacity planning realities, which take into account all hours of the year, and not just peak hour or seasonal peak needs, dictate use of the 12 CP demand allocator. Staff and other parties assert that KCPL has historically used the 4 CP method, that the 12 CP method would allocate more plant investment and costs to Missouri and less to Kansas, and that KCPL's high peak demand from June until September is more akin to a 4 CP than a 12 CP system.
>
> The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff. As on all issues, KCPL bears the burden of proof.
>
> ....
>
> ...not only Staff, but Praxair, Ford, and Missouri Industrial Energy Consumers support the 4 CP methodology. Their evidence showed that a 4 CP methodology for a utility such as KCPL is appropriate because its non-summer peak demands are significantly lower than the summer peak demands. Moreover, Praxair witness, Maurice Brubaker, has testified hundreds of times on cost allocation issues, and his testimony was that the Commission should use the 4 CP method. In addition, Staff witness Maloney convincingly disputed KCPL's claim that its system is similar to The Empire District Electric Company's system, for which Staff recommended a 12 CP method. Maloney testified that Empire's winter peaks are higher in relation to its summer peaks than are KCPL's peaks. The less developed gas distribution system in Empire's more rural service area results in more electric space-heating use in Empire's area, accounting for a higher winter load for Empire than for KCPL. KCPL's lower winter load suggests that a 4 CP allocation is more appropriate than a 12 CP method.

In KCPL's 2006 rate case, the Commission indicated the appropriateness of use of the 4 CP method to allocate KCPL's production and transmission plant investment and also related expenses, because KCPL's system load is based on much higher summer peaks compared to the rest of the year—the non-peak months. The peak months are June, July, August and September of any given year. Just as it was appropriate to use the 4 CP method in 2006 rate case when the Commission authorized the use of this method of allocations, it is equally appropriate in this rate case. The same relationship continues to exist for the summer peak months to the non-summer peak months as it did almost 10 years ago in the 2006 rate case and, indeed, since being used by KCPL when it filed its 1985 rate case using the 4 CP method to allocate production and transmission plant.

Staff reviewed the relationship of the summer peaking months of June through September and determined the relationship found in the 2006 rate case continues to this one. As was the case in the 2006 rate case, the system load factor is better in Missouri than KCPL's other main jurisdiction, the eastern part of Kansas.

System Load Factors

KCPL's system load is essentially more efficient in Missouri than Kansas—its other main jurisdiction or the FERC wholesale jurisdiction. A common measure of how efficiently a utility is meeting its system load requirements is its "system load factor" or its "load factor." KCPL's system load factor in Missouri has consistently been higher than in Kansas.

Load factor is a measure of the efficiency of the use of the physical facilities to deliver electricity to customers. More specifically, it is the ratio of the system output to peak demand during a specific period of time, either monthly or, more typically, on an annual basis. Load factor is expressed as a percentage. The higher the load factor, the more efficient the system. An electric utility like KCPL that serves three different jurisdictions; Missouri retail, Kansas retail and FERC wholesale; has separate load factors for each jurisdiction. Historically, Missouri has had the better (highest) load factor; therefore, it is KCPL's most efficient operation compared to the other two jurisdictions.

The load factor is calculated by dividing the average hourly load by the maximum hourly load (the peak demand) for a given year. This calculation can be stated as the annual energy (for 2014 in Missouri annual energy was 8,876,838 megawatts hours) divided by the number of hours in year (8,760 total hours) divided by the annual peak of a given year. For 2014, the average hourly load for Missouri was 1,013.3 megawatts with the maximum hourly load (2014 annual peak load) of 1,828 megawatts, resulting in the 55% load factor [Data Request No. 0513, Case No. ER-2006-0314, Data Request No. 0416, Case No. ER-2010-0355 and Data Request No. 0428 in Case No. ER-2014-0370].

KCPL has a better system load factor in Missouri because it has a better "mix" of customers between the different rate classes in Missouri than it does in Kansas. KCPL's Missouri operations comprise a more diverse mix of residential, commercial and industrial (large users) classes of customers, which allows it to more efficiently use its facilities, which in turn results in lower overall costs. KCPL's customers in Missouri have a higher concentration of large industrial users and a better mix of small, medium and large customers that provide better use of KCPL's facilities, and historically, a higher load factor.

KCPL's Missouri retail jurisdiction consistently has had a better load factor than its other two jurisdictions (wholesale and Kansas retail) dating back at least to the early 1980s. The system load factors for the three jurisdictions—Missouri, Kansas and the FERC wholesale- appear as a percentage—the higher the percentage the better load factor.

The load factors in the two state jurisdictions, along with the wholesale jurisdiction are:

Year	Missouri	Kansas	Wholesale
2014	55%	51%	n/a
2013	54%	52%	n/a
2012	54%	45%	n/a
2011	55%	45%	n/a
2010	55%	49%	n/a
2009	59%	44%	51%
2008	57%	49%	46%
2007	56%	48%	46%
2006	52%	45%	62%
2005	56%	47%	59%
2004	55%	46%	56%
2003	51%	44%	54%
2002	55%	47%	56%
2001	54%	46%	56%
2000	56%	46%	53%
1999	55%	44%	53%

[Source: Data Request No. 0428 in Case No. ER-2014-0370; Data Request No. 0416 in Case No. ER-2010-0355; Data Request No. 0513 in Case No. ER-2006-0314]

Up to 2012, the Missouri retail jurisdiction load factor has been in the mid- to lower 50% range while the Kansas retail jurisdiction load factor has always ranged from a low of 37% in 1986 to a high of 52% in 2013. In 2012 and 2013, Kansas has shown an improvement in the load factor, but that may be a result of some abnormal summer months in June and July 2013 in Kansas.

This was described in the direct testimony in this proceeding of KCPL witness Albert R. Bass at page 4. In any event, KCPL's Missouri jurisdiction continues to display a higher load factor.

KCPL's wholesale jurisdiction load factors have compared favorably to those of its Missouri retail jurisdiction over the years; however, KCPL's sales in the wholesale jurisdiction are a very small part of KCPL's total operations, currently less than 1% of KCPL's business. Since 2010, KCPL has not provided wholesale jurisdiction load factor information, as wholesale sales have been declining over the recent past years.

Distribution Plant Investment

In its records kept in accordance with FERC accounting requirements, KCPL separately accounts for its investment in distribution plant located in Kansas and Missouri. Plant identified in this way is referred to as site specific or *situs* plant. Staff used KCPL's actual distribution plant investment in both Missouri and Kansas at March 31, 2014, to develop site specific allocation factors to allocate the total company distribution plant and reserve amounts to quantify only the distribution plant and reserve amounts specific to KCPL's Missouri retail jurisdiction. This is consistent with how KCPL treated distribution plant in its case,

General Plant Allocation

Staff created the Missouri retail jurisdictional allocation factor for general plant investment, and related costs, based on a composite of its demand allocation factor and site specific allocation factor. Staff applied the demand allocation factor used to quantify the Missouri retail jurisdictional share of KCPL's production and transmission costs and the site specific allocation factor used to allocate an appropriate part of KCPL's total company distribution plant and reserve amounts to KCPL's Missouri retail jurisdiction. Staff used the resulting production plant and depreciation reserve amounts and distribution plant costs allocated to KCPL's Missouri retail jurisdiction to form the basis for allocating KCPL's general plant to its Missouri retail jurisdiction. Thus, Staff's Missouri retail jurisdiction allocation factor for KCPL's general plant is based on a composite of the Missouri retail jurisdiction allocation factors Staff developed for KCPL's production, transmission and distribution plant costs. Staff used this composite general plant allocation factor to allocate to KCPL's Missouri retail jurisdiction what are described in KCPL's income statement (Staff Accounting Schedule 9) as "general" costs.

Allocations of Expenses

Using the principle that expenses (costs) should follow plant investment, Staff used the same jurisdictional allocation factors it developed to allocate investment to allocate expenses related to that investment. The FERC expense accounts found in KCPL's income statement (reproduced as Schedule 9 in Staff's Accounting Schedules) include amounts for costs broadly described as production, transmission, distribution, general, and administrative and general ("A&G"). Using the expense accounts found in KCPL's income statement, this principle that expenses should follow plant investment is appropriate because KPCL incurs production (generation) plant expenses to maintain and operate its the generation facilities, making it proper to use the same jurisdictional allocator to allocate production plant expenses that is used to allocate its investment costs in generating facilities. Similarly, KCPL incurs transmission expenses to maintain and operate its transmission facilities, making it appropriate to use the same jurisdictional allocator to allocate transmission expenses that is used to allocate KCPL's investment costs in transmission facilities.

Staff allocated KPCL's production and transmission costs taken from KCPL's income statement to KCPL's Missouri retail jurisdiction with the same demand allocator Staff developed and used to allocate KCPL's investment in generating and transmission facilities to KCPL's Missouri retail jurisdiction.

Other Costs Allocations

Staff also used a variety of jurisdictional allocation factors to allocate the appropriate part of KCPL's administrative and general costs found in KCPL's income statement (Staff Accounting Schedule 9), to KCPL's Missouri retail jurisdiction. Staff relied on KCPL for these allocation factors. Some of these allocation factors are based on the number of KCPL customers in each jurisdiction. Some are based on the number of KCPL employees working in each jurisdiction. Each specific account had a specific allocation factor that Staff used to allocate the appropriate cost to KCPL's Missouri retail jurisdiction.

Energy and Demand Allocations

Staff used the energy allocation factor to allocate costs to the Missouri retail jurisdiction that are considered to vary directly with electricity usage. For example, in response to increased demand for electricity, KCPL must either buy or generate more electricity, causing one or more of its fuel and purchased power costs to increase—there is a direct relationship in the level of megawatts generated or purchased, and the amount of fuel and purchased power costs. In contrast, costs such as fixed capacity or demand charges are constant, regardless of the demand for electricity and, therefore, are allocated using the demand allocator.

The rationale for the demand component of a capacity purchase or sale is to recover the fixed costs of the facilities that underlie these transactions. For example, if KCPL sells capacity, KCPL makes a commitment to have generating capacity in place that is dedicated to meeting the load requirements of the customer to whom it is selling the capacity. This is similar to KCPL's requirement to have fixed capacity available to meet the load requirements of its residential, commercial and industrial customers (referred to as its "native load") at all times of the day and any day of the week. The demand component of a capacity sale can be thought of as the recovery of the fixed costs of generating assets used to provide electricity to the buyer of power, similar to the way fixed costs of a utility are recovered in rates from its customers. Similar to when it sells capacity, when KCPL purchases capacity to assure it can meet its load with energy, it will pay a demand component (fixed charge) to the seller. These demand components are assigned or allocated to the jurisdictions with a demand allocator. However, energy sold or purchased using that capacity is a variable cost and is allocated to the jurisdictions with energy allocation factors.

KCPL meets its native load with the same generating plant and transmission plant that it uses to generate and transport electricity to make off-system sales—sales to firm and non-firm customers in the bulk power markets (off-system sales). Staff uses the energy allocation factor to allocate energy (variable) costs of fuel and purchased power incurred to meet system load requirements of KCPL's native load customers. Staff also used the same energy factor used to allocate the variable costs incurred to meet retail load requirements for Missouri retail customers to allocate KCPL's revenues and energy costs incurred to make off-system sales to its Missouri retail jurisdiction. Since the non-firm, off-system sales market is made up of short-term sales, KCPL does not reserve dedicated capacity for these sales. Traditionally, non-firm off-system sales have been allocated using the energy allocation factors since the costs of making these sales are variable in nature, primarily being the cost of the fuel used to generate the electricity sold. As more megawatts are sold, more fuel is consumed or power purchased and, therefore, the higher the fuel cost or the purchased power cost. These costs vary directly with the megawatt hours sold or purchased and, thus, using energy allocation factors is proper. Staff has used energy allocation factors to allocate off-system sales to KCPL's Missouri retail jurisdiction in each of KCPL's last four rate cases during its Regulatory Plan and in the last case. Staff has consistently used energy allocation factors to allocate off-system sales revenues to the Missouri retail jurisdictions of The Empire District Electric Company and for setting retail rates in what is now GMO's MPS rate district for many rate cases dating back to at least the 1990s. GMO's L&P rate district is a Missouri jurisdictional only utility so has no jurisdictional allocations.

Staff Expert/Witness: Cary G. Featherstone

XIV. Fuel Adjustment Clause (FAC)

A. FAC - Policy

On May 6, 2004, KCPL filed an application in Case No. EO-2004-0577, requesting that the Commission "open an investigatory docket, to provide notice and establish a workshop process ... to discuss, and hopefully gain consensus on, constructive regulatory responses to emerging issues that will affect the supply, delivery and pricing of the electric service provided by KCP&L."

In response to KCPL's application, the Commission opened Case No. EW-2004-0596. During 2004 and 2005, interested stakeholders submitted a series of comments and the Commission held a workshop and an on-the-record conference. On March 28, 2005, KCPL, Staff, Public Counsel and several other parties filed a Stipulation and Agreement which included an Experimental Regulatory Plan (Regulatory Plan), opening Case No. EO-2005-0329.[77] On July 28, 2005, the Commission issued a Report and Order approving the Regulatory Plan and on August 23, 2005, the Commission issued an Order approving amendments to the Regulatory Plan. Relevant to KCPL's request for a fuel adjustment clause in this rate case, the Regulatory Plan states:

[77] Stipulation and Agreement, Case No. EO-2005-0329. Filed March 28, 2005.

> KCPL agrees that, prior to June 1, 2015, it will not ***seek to utilize*** any mechanism authorized in current legislation known as "SB 179"[78] or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors. ***In exchange for this commitment***, the Signatory Parties agree that if KCPL proposes an Interim Energy Charge ("IEC") in a general rate case filed before June 1, 2015 in accordance with the following parameters, they will not assert that such proposal constitutes retroactive ratemaking or fails to consider all relevant factors.[79] (emphasis added)

Two of the six listed parameters were that:

> (i) [t]he rates and terms for such an IEC shall be established in a rate case along with a determination of the amount of fuel and purchased power costs to be included in the calculation of base rates [and] (ii) [t]he rate or terms for such an IEC shall not be subject to change outside of a general rate case where all relevant factors are considered.[80]

The Commission approved the Regulatory Plan, stating:

> KCPL has agreed that before June 1, 2015, it will not seek to use any mechanism authorized in SB 179, enacted this year, or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors.[81]

However, the Commission went on to recognize that KCPL could "***propose*** an Interim Energy Charge ("IEC") in a general rate case filed before June 1, 2015" within certain parameters.[82] (emphasis added) From a policy perspective, and without addressing the fundamentals of the proposed FAC, these excerpts demonstrate that KCPL agreed that it would not seek a FAC prior to June 1, 2015; instead, both the Regulatory Plan and the Commission's Report and Order

[78] On January 1, 2006, Senate Bill 179 (SB 179), codified as Section 386.266 RSMo, became law. It allows interim energy charges or periodic rate adjustments outside of general rate proceedings. Section 386.266 provides in part:

> 386.266.1. Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.

[79] Stipulation and Agreement, Case No. EO-2005-0329, Paragraph III.B.1.c. Single-Issue Rate Mechanisms.

[80] *Id.*

[81] Report and Order, Case No. EO-2005-0329, Page 15. Issued July 28, 2005. Effective August 7, 2005.

[82] *Id.*

acknowledge that KCPL could propose an IEC in a general rate case filed before June 1, 2015, subject to certain parameters.

One of the FAC issues in this case is the interpretation of the sentences from the Regulatory Plan set out above – specifically, whether, according to the Regulatory Plan, KCPL may request a FAC in a rate case filed before June 1, 2015, without violating the Regulatory Plan. This is not the first time this issue has arisen. In Case No. EU-2014-0077, the Commission stated "As part of a general rate case, KCP&L ***may seek an FAC*** to include transmission costs ***in June of 2015***."[83] (emphasis added) However, in a later order in that case, the Commission essentially decided that the issue of the interpretation of the Regulatory Plan was not "ripe" and stated, "The Commission is not directing KCP&L on when KCP&L ***may file*** a rate case requesting an FAC for transmission costs ***or*** when KCP&L ***may implement*** such an FAC. Any decisions regarding the interpretation of the 2005 settlement agreement [the Regulatory Plan] may be determined in a future rate case."[84] (emphasis added)

Staff's position is that the Regulatory Plan prohibits KCPL from even requesting a FAC in a rate case filed prior to June 1, 2015. As the Commission is aware, this rate case was filed before June 1, 2015. In addition to concerns related to prematurely relieving KCPL from its 2005 commitment, allowing KCPL to request a FAC prior to June 1, 2015, inappropriately shifts risk to ratepayers - risks they would not have to undertake for several more months under the terms of the agreement. In Case No. ER-2012-0174, KCPL witness Tim M. Rush explains:

> Q. Is the request made by [KCPL] for an IEC or a Fuel Adjustment Clause ("FAC")?
>
> A. The request is definitely for an IEC, not an FAC. [Staff witness] Mr. Featherstone explains quite well the differences between an IEC and an FAC on pages 23 and 24 of his Rebuttal Testimony. I'll summarize those differences below:
>
> FAC – An FAC is a pass through of cost differences: it has an opportunity for review and a process to address improper cost recovery; it offers periodic rate changes between rate cases; for the current Missouri FACs only a percentage of costs are passed through the clause to the customer and none have a limitation on what increases are passed on to customers or the savings retained by shareholders.

[83] Report and Order, Case No. EU-2014-0077, Page 11, Issued July 30, 2014.
[84] Order Denying Application for Clarification, Case No. EU-2014-0077, Pages 2 – 3, Issued October 15, 2014.

> IEC – An IEC is not a pass through of costs; costs are collected on an interim basis; the IEC has a base and ceiling; it is active for a defined period of time; an IEC has a provision for a prudency audit and true up review; the IEC is in and of itself an incentive for the company to keep costs below floor.[85]

As mentioned, the Regulatory Plan provides:

> KCPL agrees that, prior to June 1, 2015, it will not seek to utilize any mechanism authorized in current legislation known as "SB 179" or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors. In exchange for this commitment, the Signatory Parties agree that if KCPL proposes an Interim Energy Charge ("IEC") in a general rate case filed before June 1, 2015 in accordance with the following parameters, they will not assert that such proposal constitutes retroactive ratemaking or fails to consider all relevant factors[86]

One of the "mechanisms" authorized in SB 179 (now Section 386.266 RSMo) is an IEC. To provide meaning to the applicability of the June 1, 2015, date, both the first and the second sentences of the Regulatory Plan quoted above should be read together. It is significant that the date in both sentences – June 1, 2015 – is the same. The second sentence qualifies the first sentence by allowing KCPL to do something it could not under the first sentence. If the first sentence means that KCPL could request a SB 179 mechanism in a rate case filed before June 1, 2015, as long as that mechanism did not become effective until after June 1, 2015, then the date in the second sentence would be meaningless. Therefore, the first sentence must mean that KCPL is not permitted to request a FAC or any other SB 179 mechanism before June 1, 2015, while the second creates an exception to that broad prohibition by allowing KCPL to request an IEC (but not a FAC) before June 1, 2015.

KCPL previously recognized that the Regulatory Plan prohibits it from requesting a FAC prior to June 1, 2015. In Case No. ER-2012-0174, which involved a request by KCPL for an IEC, KCPL's witness Mr. Rush stated:

> Q: Does the Company have a Fuel Adjustment Clause ("FAC")?
>
> A: No, it does not. Per the Stipulation and Agreement ("Stipulation") approved in 2005 by the Commission in KCP&L's Experimental Regulatory Plan ("Regulatory Plan") docket, Case No. EO-2005-0329, the

[85] Surrebuttal Testimony of Tim M. Rush. Case No. ER-2012-0174. Page 18, beginning at line 19 through page 20, line 9. October 8, 2012.

[86] Stipulation and Agreement, Case No. EO-2005-0329, Paragraph III.B.1.c. Single-Issue Rate Mechanisms.

> Company agreed that it **will not seek a FAC prior to June 1, 2015.** However, the Company is not prohibited from requesting an IEC.[87] (emphasis added)

During the evidentiary hearing, Mr. Fischer, counsel for KCPL, responded to questions posed by Judge Jordan as follows:

> **Mr. Fischer**: Yes, Judge. In the – in the original regulatory plan stipulation, Kansas City Power & [L]ight ***agreed that it would not seek a fuel adjustment clause*** for mechanisms related to, I think it was S[B]-179.
>
> But it was reserved in that stipulation that the company request what's called an interim energy charge. That's a – that's [a] mechanism that had been used previously before fuel adjustment legislation for – I think for Empire and for Aquila.
>
> And the company specifically reserved the opportunity to ask for that kind of treatment, and that's what we're doing in this case. [88] (emphasis added)
>
> * * *
>
> **Judge Jordan**: Okay. Well, my question is, when the utilities signed the stipulation that there would be no FAC, doesn't that mean that they took on the risk of rising fuel costs for themselves? Isn't that what that means?
>
> **Mr. Fischer**: Well, it means that they aren't going to take advantage of the particular mechanisms, the FAC mechanism, but they did reserve the opportunity to use an[other] mechanism, which is sort of an alternative approach that had been used in the past by the Commission. And that was called an interim energy charge. And that's what we're requesting in this case.
>
> Now, ***as the provisions expire*** down the road, ***in 2015***, the company may very well want to come into the fold of all the other utilities and ***ask*** for a fuel adjustment clause.[89] (emphasis added)

Later in the evidentiary hearing, Staff Counsel Kevin A. Thompson and KCPL's Mr. Rush engaged in the following exchange:

> Q. And so what the IEC is an attempt to do is an attempt to be a short-term solution until you believe -- until you would -- outside of the stipulation and agreement to ***request*** an FAC?
>
> A. That is correct. . .[90] (emphasis added)

[87] Direct Testimony of Tim M. Rush. Case No. ER-2012-0174. p. 10, ll. 4-8.
[88] Transcript of Proceedings, Case No. ER-2012-0174, Vol. 14, p. 135, ll. 20 through p. 136, ll. 6, October 17, 2012.
[89] Transcript of Proceedings, Case No. ER-2012-0174, Vol. 14, p. 136, ll. 17 through p. 137, ll. 7, October 17, 2012.
[90] Transcript of Proceedings, Case No. ER-2012-0174, Vol. 14, p. 238, ll. 11 through 15, October 17, 2012.

As shown in these quotes from Case No. ER-2012-0174, even KCPL once recognized that its Regulatory Plan prohibits it from asking for a FAC prior to June 1, 2015, not just from making a FAC effective prior to June 1, 2015. To read the agreement any other way – such as allowing a FAC to be requested prior to June 1, 2015 if it is not effective until after June 1, 2015 – would mean a FAC request could have been filed as early as July 2014. Yet, the Regulatory Plan did not state that a FAC could be requested in July 2014, but made it clear only an IEC could be requested prior to June 1, 2015.

Staff cannot support the request for a fuel adjustment charge (FAC) in a rate case filed prior to June 1, 2015 since the Regulatory Plan prohibits KCPL from proposing a FAC prior to June 1, 2015. Staff witness Dana E. Eaves provides testimony as to whether KCPL meets other criteria and requirements for a FAC, and will propose an appropriate FAC structure in the event that the Commission allows a FAC for KCPL.

Staff Expert/Witness: Natelle Dietrich

B. FAC - Structure

1. Recommendation

In this section, Staff will address whether KCPL meets the criteria for implementing a Fuel Adjustment Clause (FAC) which has been previously utilized by the Commission. Staff will also propose its recommendation as to the design of a FAC if the Commission grants KCPL's request to adopt a FAC. Staff witness Natelle Dietrich addresses the policy issues of Staff's position that KCPL's request in this case violates the terms of the Stipulation and Agreement in Case No. EO-2005-0329.

In summary, Staff recommends the Commission *not* grant KCPL's request for the implementation of a FAC as it has not met all of the three criteria for determining whether an electric utility should be allowed to implement a FAC. First, is the cost of such a magnitude it would have a material impact on the utility's earnings? Second, is the cost outside of the control of the utility? Third, is the nature of the cost component volatile? As will be discussed in more detail below, Staff notes:

1. KCPL has demonstrated that the magnitude of its prudently incurred fuel and purchased power costs could have a material impact on the utility.

2. KCPL has *not* demonstrated its inability to prudently manage its fuel and purchased power costs.

3. KCPL has *not* demonstrated that fuel, purchased power and transmission costs[91] are volatile.

If the Commission grants KCPL's request to adopt a FAC, Staff is proposing a FAC structure that includes a 95/5 percent sharing mechanism between KCPL's customers and KCPL of certain prudently incurred fuel and purchased power costs, Southwest Power Pool (SPP) costs and revenues, transmission costs and revenues, and off-system sales revenue. Staff is recommending to specifically exclude SPP Administrative Service charges associated with SPP Schedule 1-A[92] and SPP transmission costs and revenues associated with SPP Schedule 11. Staff is also proposing two six-month Accumulation Periods: October through March and April through September, and one twelve-month Recovery Period to commence three months after the close of the Accumulation period. Staff will provide its Base Factor calculation for this case that reflects Staff's proposed FAC design when Staff files its Class Cost of Service (CCOS)/Rate Design Report on April 16, 2015. Staff's Base Factor calculation will be developed from Staff's Base Energy Cost as provided in Staff's CCOS. Staff will also provide at that time a redline version of the revised tariff sheets that represent Staff's recommended structure for the implementation of a FAC, and any additional recommended reporting requirements needed for implementation of the FAC, if the Commission grants KCPL's request.

2. History

Senate Bill 179, now codified as Section 386.266 RSMo, was passed in 2005. Section 386.266.1 RSMo provides in part:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation.

[91] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Schedule 11 - Base Plan Zonal Charge and Region-wide Charge.
[92] Southwest Power Pool – Open Access Transmission Tariff, Sixth Revised Volume No. 1 – Schedule 1-A Tariff Administration Service.

Section 386.266 grants the Commission the authority to approve, modify, or reject the electric utility's request. It also states that the Commission may provide the electric utility with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities.

Prior to the passage of SB179, fuel and purchased power costs were afforded regulatory treatment and included in the determination of the utility's revenue requirement in general electric rate proceedings. If the electric utility managed its fuel and purchased power procurement activities in a manner that allowed it to reliably serve its customers at a cost lower than what was included in its revenue requirement in the general electric rate proceeding, the savings were retained by the electric utility. If the actual fuel and purchased power costs were greater than the cost included in the revenue requirement in the general electric rate proceeding, the electric utility's stockholders absorbed the increased cost.

3. Compliance with FAC Criteria

Staff is recommending the Commission *not* grant KCPL's request for a FAC because KCPL has not proven that it meets all of the criteria previously utilized by the Commission for determining whether an electric utility should be allowed to implement a FAC. The Commission has previously determined that a cost or revenue change should be recovered through a FAC only if the cost or revenue change is of such a magnitude it would have a material impact on the utility; is outside the control of the utility; and volatile in amount. See, for example, *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093, Issued July 30, 2008, Page 37. This criteria is also consistent with 4 CSR 240.20.090(2)(C) which states:

> (C) In determining which cost components to include in a RAM, the commission will consider, but is not limited to only considering, the magnitude of the costs, the ability of the utility to manage the costs, the volatility of the cost component and the incentive provided to the utility as a result of the inclusion or exclusion of the cost component. The commission may, in its discretion, determine what portion of prudently incurred fuel and purchased power costs may be recovered in a RAM and what portion shall be recovered in base rates.

Staff used these criteria in its evaluation of KCPL's FAC request in this case. In considering KCPL's FAC request Staff first determined if the costs of the items KCPL is seeking to include in a FAC are of such <u>*magnitude*</u> they would materially impact the utility. Fuel used by KCPL to generate electricity is comprised mainly of coal, nuclear, natural gas and oil which totaled ** __________ **, ** ________ **, ** ________ ** and ** ________ **, respectively for the 12-month period ended March 31, 2014. Fuel and transportation costs are approximately **— ** percent of KCPL's operating revenues. KCPL, in its request, is seeking to include for recovery in its proposed FAC: fuel, purchased power, SPP charges including Administration Fees, and transmission costs to be offset by off-system sales revenues, SPP revenues and transmission revenues[93].

KCPL's fuel and transportation costs alone are of such a magnitude it meets the first criterion.

The second criterion is whether the utility has the <u>*ability to manage*</u> the costs being sought for recovery in the proposed FAC. The fuel costs that KCPL is proposing to flow through its FAC request are coal, coal transportation, natural gas, nuclear fuel, and oil. KCPL generates **___** percent of its electricity from coal-fired power plants, **___** percent from nuclear fuel, ** ________ ** percent from natural gas, and ** ________ ** percent from oil[94]. ** ____ ______________________ ** The price of coal and the associated transportation costs are established by national or international markets, so KCPL does not have complete control over commodity prices. The same is true of the markets for natural gas, nuclear fuel, and oil. However, KCPL does have highly effective mechanisms in place that optimize its ability to acquire fuel at the best cost possible and for long terms. KCPL employs a staff of experts that administers its purchasing and hedging strategies. While KCPL clearly cannot control the commodity markets in which it must purchase its fuel, it does exercise considerably more control over the prices it pays for fuel and purchased power than do its ratepayers who must simply pay the rates set by the Commission.

The third criterion is whether the costs that will be tracked in KCPL's proposed FAC are <u>*volatile*</u>. Coal and the transportation costs comprise the majority of KCPL's fuel costs.

[93] KCPL's proposed positions on components being sought for recovery are different from the components that are being recommended by the Staff.
[94] From Fuel and Purchased Power Section of Staff's Cost of Service Report.

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The cost of coal and the transportation costs[95] are ** — ** percent of total fuel costs for the test year. ** ** [96] ** **

Another significant cost KCPL is seeking to include in its proposed FAC is purchased power costs off-set by off-system sales. KCPL participates in SPP, a regional transmission organization (RTO). As of March 1, 2014, SPP implemented its IM in which SPP is responsible for the market operations for 127 participants and 627 generating resources in 9 states[97]. Purchased power under the RTO scenario is the power KCPL buys back from SPP to meet the needs of its customers. ** ** The price at which KCPL purchases energy from the market will be at a rate set by SPP that reflects a market price. However, KCPL is paid at a SPP set market price for the generation it sells into the market that is designed to cover all of KCPL's generation costs. KCPL could receive additional revenue if the market price is in excess of the cost of generating the power. Although energy prices are not certain, the existence of SPP IM market operations seeks to utilize the least expensive available energy[98].

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95 ** ** KCP&L's response to Staff's Data Request No. 0078, Highly Confidential.

96 KCPL's response to Staff's Data Request No. 0068, Highly Confidential.

97 http://www.spp.org/publications/Intro_to_SPP_OCTOBER%202014.pdf.

98 Southwest Power Pool 2014 Strategic Plan, page 6; **Market Operations**: The Integrated Marketplace launched in 2014 and replaced the existing Energy Imbalance Service market. It includes a Day-Ahead Market with Transmission Congestion Rights, a Reliability Unit Commitment process, a Real-Time Balancing Market replacing the EIS Market, and the incorporation of price-based Operating Reserve procurement. It is expected to yield its more than 115 participants up to $100 million in annual net savings by allowing load serving participants to use the least expensive available energy in the SPP footprint regardless of ownership while maintaining the reliability of the transmission system. It also allows generation owning participants another avenue to sell their energy.

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The SPP Schedule 11 transmission costs and revenues KCPL is seeking to track through its proposed FAC are rising, but in Staff's opinion are not volatile, as shown in the following chart as provided by Tim Rush:[99]

The Commission discussed this issue of rising costs "vs" the volatility of costs being included in a FAC in its Report and Order in case ER-2007-0002[100].

> Markets in which prices are volatile tend to go up and down in an unpredictable manner. When a utility's fuel and purchased power costs are swinging in that way, the time consuming ratemaking process cannot possibly keep up with the swings. As a result, in those circumstances, a fuel adjustment clause may be needed to protect both the utility and its ratepayers from inappropriately low or high rates. Because AmerenUE's costs are simply rising, that sort of protection is not needed. As Brosch explains, rising, but known, fuel costs are the worst reason to implement a fuel adjustment clause because such a fuel adjustment clause allows the utility to recover a single known rising cost while avoiding a rate case in which all its other expenses and revenue, which are changing in the background, will be examined and perhaps used to offset all or part of the rising fuel cost to avoid an unnecessary rate increase.

Staff contends that because SPP's Transmission Schedule 11 costs are known and measurable[101] traditional rate making practices would be more than sufficient to allow KCPL a reasonable opportunity to recover these costs from customers on a going forward basis; thus, KCPL would not need special regulatory treatment afforded this individual cost item. KCPL will also share in

[99] Direct Testimony of Tim M. Rush on Behalf of KCPL, p. 11.

[100] REPORT AND ORDER, In the Matter of Union Electric Company d/b/a Ameren UE's Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area, Case No ER-2007-0002, p. 23.

[101] Direct Testimony of Tim M. Rush on Behalf of Kansas City Power & Light Company, page 20, lines 17-18: "This equates to a substantial increase of approximately 16% per year from 2013-2022."

escalating transmission revenues associated with the cost of additional transmission projects and that will aid in off-setting the rising transmission costs.

While fuel prices and other costs that KCPL is seeking to recover in its proposed FAC can be volatile in nature, the fuel acquisition strategies KCPL employees mitigates this volatility in the market. Staff contends that KCPL's fuel, purchased power, and transmission costs are not volatile and would not prevent KCPL from reasonably earning its authorized return.

4. FAC Request Filing Requirements

The filing requirements for establishing a FAC are found in Commission Rules 4 CSR 240-20.090(2) and 4 CSR 240-3.161(2).

The Staff has reviewed and analyzed the requirements as provided in 4 CSR 240-20.090(2) and 4 CSR 240-3.161(2) in an effort to ensure KCPL's request for a FAC has met these filing requirements. KCPL has complied with the filing requirements contained in 4 CSR 240-20.090(2) and 4 CSR 240-3.161(2).

Staff Expert/Witness: Dana E. Eaves

5. Loss Study Compliance / FAC Voltage Adjustment Factors

Rule 4 CSR 240-20.090(9) requires an electric utility that desires to implement a Rate Adjustment Mechanism ("RAM"), such as the current request of KCPL to initiate a Fuel Adjustment Clause ("FAC"), to complete a jurisdictional system loss study of the corresponding energy losses experienced in its delivery of electricity. This study must be conducted within twenty-four months prior to the general rate case in which it requests its initial RAM.[102] The KCPL Loss Study, R075-14-Revision 1, was provided in KCPL's response to Staff Data Request No. 0172. The study is dated October 29, 2014 and contains system loss calculations/determinations based on data collected during calendar year 2013. Staff used the information in this loss study in developing the following primary and secondary voltage level adjustment factors:

[102] 4 CSR 240-20.090(9) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM.

Voltage Level	Voltage Adjustment Factor
Primary	1.0452
Secondary	1.0707

These voltage adjustment factors account for the energy losses experienced in the delivery of electricity from the generator to the customer. These factors will be utilized in Staff's determination of a Fuel Adjustment Rate (FAR), applicable to the individual voltage service classification of a particular customer in the corresponding FAC tariff, in the event that KCPL is authorized to implement a FAC tariff.

Staff Expert/Witness: Alan J. Bax

6. Heat Rate Testing Review

When an electric utility files to establish a Rate Adjustment Mechanism Fuel Adjustment Clause (FAC) Commission Rule 4 CSR 240-3.161(2)(P) sets forth the requirements for heat rate tests and/or efficiency tests for generating units. Specifically, it requires an electric utility that files to provide:

> (P) A proposed schedule and testing plan with written procedures for heat rate tests and/or efficiency tests for all of the electric utility's nuclear and non-nuclear generators, steam, gas, and oil turbines and heat recovery steam generators (HRSG) to determine the base level of efficiency for each of the units;

Staff's review has confirmed that KCPL provided a proposed schedule and testing plan as part of the direct testimony of KCPL witness Burton L. Crawford as indicated on Schedule BLC-6. Staff's review of the KCPL Heat Rate Testing Plan, also indicated on Schedule BLC-6, identified several dates that occurred prior to the filing date of this general rate case. As a result of this review, Staff generated Data Request No. 0396 and requested KCPL update the information in Schedule BLC-6. KCPL provided the following updated information in its response.

continued on next page

Heat Rate Testing Plan

Unit	Heat Rate Test due by
Hawthorn 5	8/21/16
Hawthorn 6-9	8/26/16
Hawthorn 7	8/4/16
Hawthorn 8	8/5/16
Iatan 1	10/3/15
Iatan 2	6/13/16
LaCygne 1	6/30/15
LaCygne 2	4/15/15
Montrose 1	6/25/16
Montrose 2	6/20/16
Montrose 3	6/27/16
Northeast 11	7/18/15
Northeast 12	7/18/15
Northeast 13	8/27/15
Northeast 14	7/18/15
Northeast 15	7/17/15
Northeast 16	7/17/15
Northeast 17	7/17/15
Northeast 18	7/17/15
Osawatomie	6/25/16
West Gardner 1	5/21/16
West Gardner 2	5/21/16
West Gardner 3	5/21/16
West Gardner 4	5/21/16

Staff reviewed the monthly heat rate testing results for the Wolf Creek nuclear generating station also included in Crawford's direct testimony as indicated on Schedule BLC-8.Staff also reviewed the heat rate testing results for the fossil fueled generating units provided in Crawford's direct testimony on Schedule BLC-9. Staff identified several conflicts between the test results and the information provided in response to Staff's Data Request No. 0261. Staff submitted Data Request No. 0395 and requested that KCPL update the table on Schedule BLC-9 to be consistent with its response to Data Request No. 0261. In response to Data Request No. 0395, KCPL provided the following **HC** information.

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KCPL provides a written procedure for heat rate testing in KCPL witness Burton L. Crawford's direct testimony as indicated on Schedule BLC-7 and identified as revision 1 of procedure ETP-002, entitled "Generating Unit Heat Rate Testing Procedure." The procedure is the product of a series of Staff reviews and feedback starting with a set of testing procedures submitted in

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Case No. EO-2008-0156 by Aquila, Inc. (Aquila), which were approved by the Commission on January 15, 2008, and procedures submitted as revision 0 in Case No. ER-2010-0356 in support of the continuation of GMO's FAC. Although not required for this filing, Staff's review of the procedure finds that in section 8.1 heat rate testing is required to be performed at least once every 2 years. This 2 year frequency standard satisfies the heat rate test frequency requirement found in the Commission Rule 4 CSR 240-3.161(3) submission requirements for continuing or modifying a FAC.

The results of Staff's review based on Crawford's direct testimony and modified by KCPLs responses to Data Request Nos. 0395 and 0396 confirms that KCPL has met the submission requirements for heat rate tests and/or efficiency tests for generating units as indicated in Commission Rule 4 CSR 240-3.161(2)(P).

Staff Expert/Witness: Randy S. Gross

XV. Other Miscellaneous Items

A. Electric Vehicle Clean Charge Network Initiative

In Staff's opinion the Electric Vehicle (EV) Clean Charge Network Initiative (Clean Charge Network or initiative) is an activity that should not be subject to Commission regulation and therefore, for the reasons outlined below, Staff recommends that the Commission not include any amount in KCPL's cost of service in this case for the expenses for the Clean Charge Network. Staff is supportive of the initiative that KCPL has undertaken to promote the adoption of electric vehicles in the KCPL service territory; however, as explained below, it should be a non-regulated service.

On January 26, 2015, KCPL announced the kickoff of the Clean Charge Network, a plan to install and operate more than 1,000 electric vehicle charging stations[103]. The Clean Charge Network is a joint initiative with GMO that is designed to "[s]erve as a catalyst for electric vehicle adoption in the Kansas City region."[104] Based on Staff's current understanding of the Clean Charge Network, this initiative may be viewed as two separate initiatives: one initiative is

[103] All references to the KCPL Clean Charge Network or initiative refer to all of the operating areas of KCPL and KCPL affiliates.
[104] KCPL response to Staff Data Request No. 0406.

a partnership between KCPL, Nissan Motor Company, and other organizations to host[105] approximately 5 fast charging stations[106]: and, the other initiative is between KCPL and other organizations to host additional charging stations[107]. Under the initial phase of the "15" initiative, KCPL will construct fast charging stations at hosts sites that will remain under KCPL ownership.[108] Under this initiative, the usage will be paid by KCPL the partnership with Nissan Motor Company. ** ______________________________ **[109] (See Highly Confidential Appendix 3, Schedule MLS-1 for details of site license agreement.)

Under the second initiative, KCPL will provide, at no cost to the host, charging stations that will be separately metered from the host facilities, but the host will be liable for the usage at the station.[110] Staff is not aware of any contracts between KCPL and the "second initiative" host sites, so it is unclear which entity retains ownership of the charging station or what the operations of the charging sites will be after the two year period. Staff is also not aware of any analysis that justifies the different treatment of charging station hosts under the initiative.

KCPL previously had an electric vehicle charging station program. Since 2011, KCPL has installed more than twenty charging stations in its Missouri service territory, some as a part of the Smart Grid Demonstration Pilot Project and others as part of a grant from the Department of Energy.[111] Prior to the January 26, 2015, kickoff announcement, KCPL installed 37 electric vehicle charging stations in its combined Kansas and Missouri service territory and seven more

[105] Staff's current understanding, based on supplemental direct testimony and data request responses, KCPL uses "host" to mean the premises of the existing customer where the EV charging station will be located and which is used for the rate at which KCPL plans to charge energy usage, i.e., energy usage to the EV charging station will be billed at the same rate KCPL charges the customer for electric service it is already receiving from KCPL.

[106] The initial initiative anticipates 15 fast charging stations – 5 in KCPL-MO, 4 in GMO and 6 in the Kansas service territory.

[107] Staff is not aware of how many of these stations will be Level 1, Level 2 or Level 3 (defining the level of charging capability), with Level 3 being the fastest charging station type.

[108] Supplemental Direct Testimony of KCPL witness Darrin R. Ives, p. 2, ll. 9 – 16.

[109] KCPL response to Staff Data Request No. 360.1.

[110] Supplemental Direct Testimony of KCPL witness Darrin R. Ives, p. 2, ll. 9 – 16.

[111] KCPL response to Staff Data Request No. 0400, "KCP&L Electric Vehicle Charging Stations Announcement" 24JUN2011. https://www.kcpl.com/about-kcpl/media-center/2011/june/electric-vehicle-charging-stations-announcement (18MAR2015), and "Electric Vehicles" https://www.kcpl.com/about-kcpl/company-overview/industry-topics/energy-efficiency/electric-vehicles (18MAR2015).

in the GMO service territory for a total of 44 electric vehicle charging stations.[112] These charging stations have not been rate regulated by the Commission and have not been included in rate base.

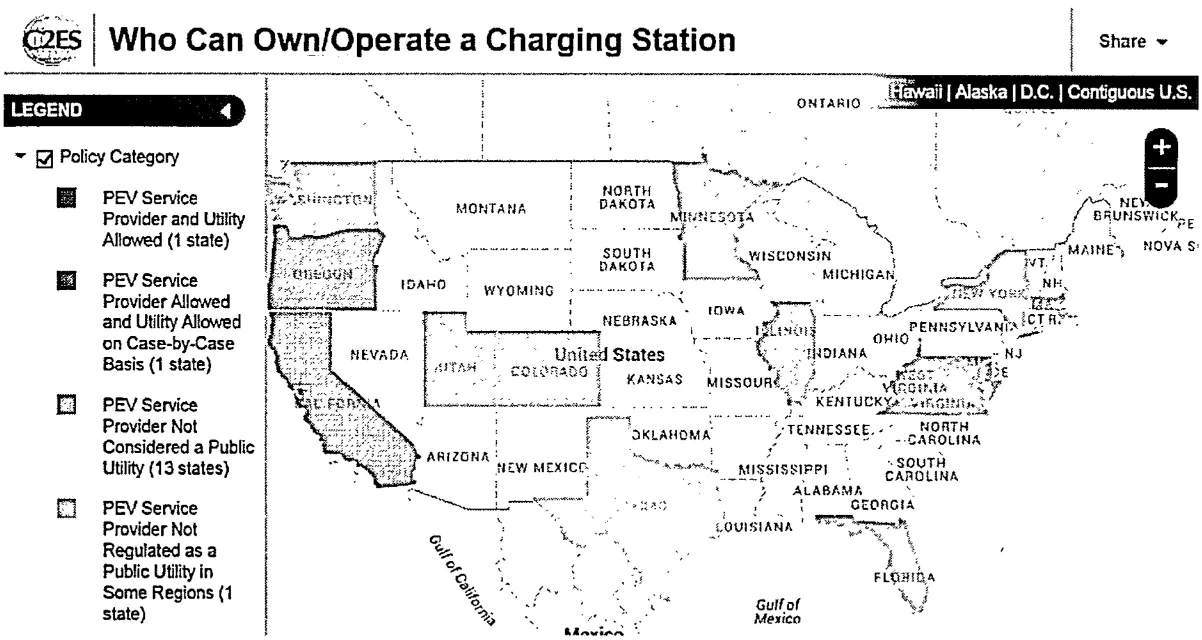
In addition to the existing KCPL electric vehicle charging stations, there are many other electric vehicle charging stations in the Missouri and Kansas KCPL service territories that have not been installed by KCPL and are not regulated by the Commission.[113] According to the ChargePoint website referenced in KCPL's response to Staff Data Request No. 0402, there are at least 151 electric vehicle charging stations in the Kansas City, Missouri region and another 40 electric vehicle charging stations in the Kansas City, Kansas region.[114] The website also indicates that a few of these stations may charge the owners of electric vehicles for charging at their stations.[115]

Figure 1 below is a screen shot of the Center for Climate and Energy Solutions website which identifies the regulatory treatment of electrical vehicle charging stations across the contiguous United States. As can be seen, "[m]any states have not yet made a distinction between the retail sale of power and the provision of public electric vehicle charging services; some states have explicitly exempted the stations from existing utility regulation and some states have a de facto unregulated position that has yet to be challenged, ruled or legislated upon."[116] Alaska, which is not shown in Figure 1, is identified as a state without a defined distinction. For the sixteen states that have a defined policy, thirteen, including Hawaii which is also not shown in Figure 1, have a policy to not consider charging stations as a public utility. Oregon's rules permit ownership of charging stations, but treat the investment as a nonregulated utility investment.[117] California prohibited utilities from owning charging stations, and exempted

[112] KCPL response to Staff Data Request No. 0400.
[113] KCPL response to Staff Data Request No. 0402.
[114] ChargePoint. https://na.chargepoint.com/charge_point (19MAR2015).
[115] For instance, the converter stations at the Kauffman Center for the Performing Arts appear to cost $1.00/hour for charging an electric vehicle in addition to the parking fee. There was no information available for electric vehicle charging stations not associated with ChargePoint. Source: ChargePoint. https://na.chargepoint.com/charge_point (19MAR2015).
[116] The Council of State Governments (2013). "State Utilities Law and Electric Vehicle Charging Stations." http://knowledgecenter.csg.org/kc/sites/default/files/Electric%20Vehicle%20Charging%20Stations_0.pdf. (19MAR2015). p. 1.
[117] The Council of State Governments (2013). "State Utilities Law and Electric Vehicle Charging Stations." http://knowledgecenter.csg.org/kc/sites/default/files/Electric%20Vehicle%20Charging%20Stations_0.pdf. (19MAR2015). p. 2.

charging stations from electric utility law.[118] However, the California Public Utility Commission recently issued an order stating: "The blanket prohibition against electric utility ownership of plug-in electric vehicle charging infrastructure adopted in Decision 11-07-029, Conclusion of Law 20 shall no longer be in effect, and shall be replaced by a case-specific approach."[119] Texas, the final exception, is more complex. Charging stations are under the regulatory authority of the Public Utility Commission of Texas and there is "a high regulatory bar for the sale of electricity" in both the competitive and noncompetitive jurisdictions in Texas.[120] The Council of State Governments has attributed this bar to reasons why there are networks of charging stations in noncompetitive jurisdictions such as Austin, where businesses can partner with the municipal power company, but has stymied networks in competitive zones like Houston.

Figure 1[121]



[118] The Council of State Governments (2013). "State Utilities Law and Electric Vehicle Charging Stations." http://knowledgecenter.csg.org/kc/sites/default/files/Electric%20Vehicle%20Charging%20Stations_0.pdf. (19MAR2015). p. 3.

[119] Public Utilities Commission of the State of California. (2014). "PHASE 1 DECISION ESTABLISHING POLICY TO EXPAND THE UTILITIES' ROLE IN DEVELOPMENT OF ELECTRIC VEHICLE INFRASTRUCTURE" http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K682/143682372.PDF (27MAR2015). p. 11.

[120] The Council of State Governments (2013). "State Utilities Law and Electric Vehicle Charging Stations." http://knowledgecenter.csg.org/kc/sites/default/files/Electric%20Vehicle%20Charging%20Stations_0.pdf. (19MAR2015). p. 2.

[121] Center for Climate and Energy Solutions. "Who Can Own/Operate a Charging Station." http://www.c2es.org/initiatives/pev/maps/who-can-own-operate-a-charging-station. (19MAR2015).

Perhaps the most comparable situation in Missouri is the treatment of Compressed Natural Gas vehicle fueling facilities. Compressed natural gas refueling stations are not Commission-regulated activities in Missouri. One natural gas company, Laclede Gas Company ("Laclede"), does have a Vehicular Fuel schedule that specifies the price at which natural gas will be sold to the station owner, but does not require the owner to sell the gas at that price. A portion of the Laclede tariff for Vehicular Fuel reads:

> This rate schedule shall apply to the sale of separately metered natural gas to customers for the sole purpose of compression by the customer or a party engaged by the customer for use as vehicular fuel, whether such fuel is used directly by the customer or is resold to other end user(s) as compressed natural gas ("CNG") for vehicular use.
>
> Service for any end-use of gas other than the compression of natural gas for vehicular use...is not permitted under this schedule...
>
> Service provided by the Company under this rate schedule does not include the provision of compression services or facilities for CNG purposes.[122]

Other utilities do not have a rate specified in their tariffs for CNG vehicle fuel facilities, but provide CNG fuel as a non-regulated service. For instance, a recent article in the St. Joseph News Press discusses the recent opening of a public CNG vehicle fuel facility by Missouri Gas Energy just prior to being acquired by Laclede.[123] According to CNGPrices.com, there are public CNG vehicle fueling facilities in the Kansas City region, two of which are in Missouri that are operated by companies not regulated by the Commission.[124]

Staff has concerns with issues that might arise should the Commission decide that regulation of electric vehicle charging stations is warranted. First, regulation would give uncertainty as to whether the current and future charging station hosts/owners would be able to charge customers to recover the expenses to install, operate, and maintain charging stations or could only be permitted to have the stations if they provide the service for free. As mentioned earlier, the Council of State Governments has attributed a high regulatory bar as the reason for a limited number of charging stations in Texas.[125]

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[122] Laclede Gas Company Tariff, PSC Mo. No. 5, Twelfth Revised Sheet 11. (Mo. PSC EFIS 2012).
[123] Scherer, R. "CNG pump shows fuel's benefits." St. Joseph News-Press, March 19, 2015.
[124] CNGPrices.com, http://www.cngprices.com/station_map.php (19MAR2915).
[125] The Council of State Governments (2013). "State Utilities Law and Electric Vehicle Charging Stations." http://knowledgecenter.csg.org/kc/sites/default/files/Electric%20Vehicle%20Charging%20Stations_0.pdf. (19MAR2015).

Another reason Staff recommends the Commission disallow Clean Charge Network expenses is that in its response to Staff Data Request No. 0365, KCPL stated that no expenses relating to the Clean Charge Network were deferred as of January 31, 2015-one month past the update period. None of the *projected estimated* expenses should be allowed for recovery from ratepayers in this rate case. KCPL is not proposing any adjustment to revenues generated by the Clean Charge Network. KCPL states that "It is not currently expected that any meaningful revenues will be generated by the Clean Charge Network before the end of the true-up period."[126] KCPL's position filing is inconsistent since KCPL is requesting $500,000 operation and maintenance expenses to increase revenue requirement, but KCPL is not recognizing any revenues related to this issue.

Staff is also concerned about the impact of the Clean Charge Network from a demand-side management perspective.[127] ICF International, as attached in Schedule DRI-2 to the Supplemental Direct Testimony of Darrin R. Ives, states that "if vehicle charging occurs coincident with peak demands, increased loads will drive a need for new investment in generation, transmission and distribution capacity."[128] Although "[p]eople generally charge their cars at non-peak periods,"[129] the provision of free charging at locations that are more likely to be used during the day may lead to increased usage at peak times rather than off-peak. According to KCPL's response to Staff Data Request No. 0411, the Clean Charge Network currently has no provision to either cease charging or draw on an electric vehicle's battery during periods of high demand. ** ____

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________ **[130] The limited data provided in response to Staff Data Request No. 0410, while insufficient to be conclusive, generally shows little to no charging during the nighttime hours and some charging between 3 pm and 6 pm, with most charging occurring between 8 am and noon. A rough view of the data appears to show consistency with the "L2 Non-Residential" loadshape

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[126] Supplemental Direct Testimony of KCPL witness Darrin R. Ives, p. 6, ll. 3-4.
[127] KCPL discusses the potential of this program as a demand-side management program in Schedule DRI-1 page 2 of 10 to the Supplemental Direct Testimony of KCPL witness Darrin R. Ives and in response to Staff Data Request No. 0411.
[128] California Transportation Electrification Assessment. Page 38.
[129] Schedule DRI-1 to the Supplemental Direct Testimony of KCPL witness Darrin R. Ives, "KCP&L Clean Charge Network Announcement" p. 3 of 4.
[130] KCPL response to Staff Data Request No. 0360.

in Figure 6 on page 33 of the California Transportation Electrification Assessment Phase 2: Grid Impacts, attached as Schedule DRI-3 to the Supplemental Direct Testimony of Darrin R. Ives.

In addition, although Staff agrees that vehicle exhaust emissions may be reduced through the use of electric vehicles, emissions from the power plants that charge the vehicles will not decrease as a result of the charging stations. While the emissions may, on net, be beneficial, Staff cannot quantify how much, if any, emissions may be reduced,[131] how the increased emissions would factor into meeting new environmental regulations, and how the operations of current power plants would be impacted.[132]

A final concern is that KCPL's filing has not met the requirements of the Commission's Promotional Practice rules. Promotional practices are defined in 4 CSR 240-3.100(13) and 4 CSR 240-14.010(6)(L) as "any consideration offered or granted by an electric utility or its affiliate to any person for the purpose, express or implied, of inducing the person to select and use the service or use additional service of the utility or to select or install any appliance or equipment designed to use the utility service, or for the purpose of influencing the person's choice or specification of the efficiency characteristics of appliances, equipment, buildings, utilization patterns or operating procedures." Consideration, per 4 CSR 240-14.010(6)(C), is to "be interpreted in its broadest sense and shall include any cash, donation, gift, allowance, rebate, discount, bonus, merchandise (new or used), property (real or personal), labor, service, conveyance, commitment, right or other thing of value". One of the stated goals of the Clean Charge Network is to build electric load,[133] potentially qualifying the program as a load-building program per 4 CSR 240-14.010(6)(J). Although characterized by KCPL to be a pilot program,[134] 4 CSR 240-14.010(6)(E) prohibits load-building programs being construed as demand-side resources. Thus, in Staff's opinion, the exemptions in 4 CSR 240-14.010(4) and (5) are inapplicable.

Prohibited Promotional Practices are discussed in 4 CSR 240-14.020. These rules prohibit any public utility, for the purpose of inducing any person to select or use additional service, from offering consideration to any person for the installation or use of appliances or

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[131] Another aspect of free electric charges can be increased usage (i.e. more miles driven), although this is likely to be limited due to the range and time to charge electric vehicles.

[132] e.g., Depending on the timing and size of electric vehicle loading, it could impact which power plants operate, when or how often they operate, and the efficiency at which they operate.

[133] KCPL response to Staff Data Request No. 0406.

[134] Supplemental Direct Testimony of KCPL witness Darrin R. Ives, p. 3, ll. 1 – 4.

equipment,[135] the provision of free or less than cost appliances or equipment,[136] the provision of free or less than cost installation, operation, repair, modification or maintenance of appliances or equipment,[137] or "[t]he financing of the acquisition of any appliance or equipment at a rate of interest or on terms more favorable than those generally applicable to sales by nonutility dealers…"[138] As discussed earlier, the KCPL initiative provides, at no cost to the host, charging stations that will be separately metered from the host's facilities.[139] KCPL also stated that it currently has no plans to continue this initiative as a permanent program or to remove the charging stations after the three-year period is completed.[140]

If the Commission determines that this initiative is not prohibited by 4 CSR 240-14.020, 4 CSR 240-14.030 prescribes standards governing the promotional practices. One of these standards is that all promotional practices shall be economically feasible and reasonably calculated to benefit both the utility and its customers.[141] Staff Data Request No. 0405 requested that KCPL provide "any and all economic feasibility studies" and Staff Data Request No. 0413 requested that KCPL provide "any and all studies, analysis, or evaluations of KCPL's or GMO's proposed Clean Charge Network that demonstrates benefits in excess of costs to KCPL's or GMO's customers who do not own electric vehicles." In response, KCPL stated that:

> As a pilot project, no specific economic feasibility study was conducted for the KCP&L Clean Charge Network ("CCN") pilot project. KCP&L believes that this pilot will show benefits that exceed costs to all customers as the electric vehicle market evolves.[142]

> As a pilot project, no specific studies, analysis or evaluations leading to a specific cost-benefit calculation for customers who do not own electric vehicles was conducted for the [KCPL] Clean Charge Network ("CCN") pilot project. Rather, [KCPL] believes, that this pilot will show benefits that exceed costs to all customers as the electric vehicle market evolves.[143]

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[135] 4 CSR 240-14.020(1)(D).
[136] 4 CSR 240-14.020(1)(E).
[137] 4 CSR 240-14.020(1)(F).
[138] 4 CSR 240-14.020(1)(H).
[139] Supplemental Direct Testimony of KCPL witness Darrin R. Ives, p. 2, ll. 9 – 16.
[140] KCPL response to Staff Data Request No. 0414. Per that data request response, the program is a three-year program where the host must provide free charging service for the first two years. After that two year period, it appears that the host may be able to charge for reselling the electricity to electric vehicle owners.
[141] 4 CSR 240-14.030(1).
[142] KCPL response to Staff Data Request No. 0405.
[143] KCPL response to Staff Data Request No. 0413.

The data requests did state that KCPL reviewed "multiple reports and studies"[144] in the development of the initiative, some of which are attached as schedules to the Supplemental Direct Testimony of Darin R. Ives.

Another standard is that "no new promotional practice...shall be made or offered unless first filed on a tariff with the commission."[145] Staff requested the tariff sheets for the Clean Charge Network in Staff Data Request Nos. 0359 and 0360. In response, KCPL stated that the service is being provided "on standard Commercial & Industrial rates, i.e. Small General Service, Medium General Service, Large General Service, or Large Power as is appropriate for the particular site."[146] However, these tariff sheets lack the information required by 4 CSR 240-3.150(2)(A), information such as the class of persons to which the promotional practice is being offered,[147] whether the promotional practice is being uniformly offered to all persons within the class,[148] a description of the promotional practice and a statement of its purpose,[149] and a statement of the terms and conditions governing the promotional practice.[150] As a further consequence, Staff cannot verify that the practice of providing charging station equipment is being offered without "any undue or unreasonable preference or advantage to any person or subject any person to any undue or unreasonable prejudice or disadvantage."[151]

The Filing Requirements for Electric Utility Promotional Practices, 4 CSR 240-3.150, also require, in addition to the tariff sheets discussed in 4 CSR 240-3.150(2), a description of the advertising or publicity to be employed.[152] If the promotional practice is designed to evaluate or acquire demand-side resources, then 4 CSR 240-3.150(3)(B) and (3)(C) require, a description of the evaluation criteria, evaluation plan, and schedule for completing the evaluation[153] or "documentation of the criteria used and the analysis performed to determine that the demand-side resources are cost-effective" as applicable. Since the Clean Charge Network is touted by

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[144] KCPL response to Staff Data Request No. 0405.
[145] 4 CSR 240-14.030(3).
[146] KCPL response to Staff Data Request No. 0360.
[147] 4 CSR 240-3.150(2)(A)2.
[148] 4 CSR 240-3.150(2)(A)3.
[149] 4 CSR 240-3.150(2)(A)4.
[150] 4 CSR 240-3.150(2)(A)5.
[151] 4 CSR 240-14.030(2). Staff cannot verify whether there is undue or unreasonable preference, advantage or prejudice among the 5 EV charging stations subject to this case. Further, Staff cannot verify whether there will be undue or unreasonable preference, advantage or prejudice related to the second initiative EV charging stations.
[152] 4 CSR 240-3.150(3)(A). Staff has requested this information form KCPL by Staff Data Request No. 0511. KCPL's response is currently pending.
[153] 4 CSR 240-3.150(3)(B).

KCPL as load building, it cannot be a demand-side resource for purposes of Chapter 14.[154] However, due to the potential of discharging EV batteries into the grid during peak hours Staff asked KCPL, in Staff Data Request No. 0411, if KCPL planned to use the Clean Charge Network as a Demand-Side Resource. In response KCPL stated that no program specifics have been designed to do so, but that it hoped to obtain data through the Clean Charge Network to evaluate the program as a demand-side resource. Additionally, KCPL stated in response to Staff Data Request No. 0406 that one of the goals of the Clean Charge Network is to "[d]evelop demand side management, rate and vehicle discharge programs for customers." However, KCPL currently has no evaluation plan and has not identified what criteria would be used to measure the success of the Clean Charge Network.[155]

In summary, Staff recommends no costs related to the Clean Charge Network be allowed.

Staff Experts/Witnesses: Michael L. Stahlman and Byron M. Murray

B. Pre-MEEIA Cost Recovery

As part of the non-unanimous Stipulation and Agreement to File No. EO-2014-0029, which addressed KCPL's practices regarding customer opt-out of Demand-Side Programs, the parties agreed that opt-out customers would receive a credit on their monthly bills equivalent to the non-MEEIA energy efficiency charges built into rate base.[156] The agreement also allowed KCPL to defer the amounts credited to customers in a separate account,[157] which is identified as CS-97 in the Direct Testimony of Ronald A. Klote. Staff has reviewed the account and has not found any issues at this time. Consistent with the aforementioned stipulation and agreement, Staff recommends these amounts being included in KCPL's base rates, subject to true-up. However, Staff also recommends that these amounts should be included in CS-100, which is the recalculated, pre-MEEIA rate.

Staff Expert/Witness: Michael L. Stahlman

[154] 4 CSR 240-14.010(6)(E.).
[155] KCPL's responses to Staff Data Request Nos. 0406 and 0411.
[156] Paragraphs 6A and 6B of the Stipulation and Agreement to EO-2014-0029.
[157] Paragraphs 6G of the Stipulation and Agreement to EO-2014-0029.

C. Pre-MEEIA DSM Programs and Cost Recovery Mechanism

KCPL presently has in place a DSM regulatory asset account mechanism[158] to allow full recovery of direct program costs for KCPL's eleven (11) pre-MEEIA demand-side management ("DSM") programs. Staff recommends that the Commission order the continuation of this account mechanism.

KCPL's first began implementing DSM programs as part of its Regulatory Plan approved on July 28, 2005, in Case No. EO-2005-0329. As a result of the Commission's *Report and Order* in KCPL's 2010 general rate case (Case No. ER-2010-00355), the Regulatory Plan ended on May 4, 2011, and KCPL was no longer required to implement DSM programs. However, KCPL continued to offer the same eleven DSM programs to its customers, and the Company's DSM Advisory Group continued to meet quarterly with KCPL's to provide guidance and support for DSM program development, implementation, monitoring and evaluation. The pre-MEEIA programs were terminated on July 6, 2014, when KCPL's MEEIA programs were implemented as a result of Case No. EO-2014-0095.

Staff Expert/Witness: Jason Huffman

1. Demand-Side Management Program Prudence

KCPL's FERC Account 182.440[159] contains costs that have been directly incurred for KCPL's DSM programs,[160] along with (1) costs not directly assignable to any individual program, and (2) DSM market research costs. Based on Staff's participation in DSM Advisory Group meetings and Staff's review of the costs in Account 182.440, Staff has no recommended disallowances to the levels of costs charged to KCPL's DSM Account.

Staff Expert/Witness: Jason Huffman

[158] All DSM programs' costs will be placed in a regulatory asset account and receive interest at the AFUDC rate. In subsequent general electric rate proceedings, prudent DSM programs' costs incurred prior to December 31, 2010 will be amortized over a ten (10) year period. Prudent DSM programs' costs incurred on or after December 31, 2010, will be amortized over a six (6) year period and the unamortized balances will be included in rate base for determining rates in the case.

[159] KCPL General Ledger, 182440 Deferred Customer Program MO.

[160] DSM programs consist of demand response, energy efficiency and affordability programs, including the low income weatherization programs.

2. <u>Rate-Making Treatment for the DSM Program Cost</u>

In its Report and Order in Case No. ER-2010-0355, with regard to how DSM past and future costs should be treated, the Commission stated:

> One area of agreement is that the —old regulatory assets (Vintages 1, 2, and 3) should be governed by the previous decisions to amortize those regulatory asset accounts over a ten-year period and that amortization period should not change. The Commission also agrees and directs that Vintages 1, 2, and 3 continue to be amortized over a ten-year period.
>
> KCP&L agrees with MDNR regarding the treatment for —future investments. The Commission agrees as well and will direct that DSM program costs for investments made from December 31, 2010, until a future recovery mechanism is in place [Vintage 5] shall be placed in a regulatory asset account and amortized over six years with a carrying cost equal to the AFUDC rate applied to the unamortized balance
>
> With regard to the —current investments, it would be inconsistent with previous Commission orders to authorize a six-year amortization for the current investments (Vintage 4). The Commission determines that these Vintage 4 investments should continue to be amortized over a ten-year period.
>
> The Commission determines that the unamortized balances of the regulatory asset accounts shall be included in rate base for determining rates in this case.

<u>Accounting Treatment for Existing Vintages</u>

Staff reviewed KCPL's proposed adjustment mechanism for DSM related costs and found that the amortization calculations are inconsistent with the Commission's Report and Order in Case No. ER-2010-0355. KCPL's proposed amortization of deferred DSM costs effectively rolls all historical vintages and the current deferred DSM balance into one regulatory asset amortized over 11 years. Staff included the DSM vintages in the revenue requirement consistent with the Commission's order above by including the unamortized balances for Vintages 1-6 in its Rate Base Schedule 2 and by including the annual amortization for each vintage based on a 10 year amortization for Vintages 1-4, a 6-year amortization for Vintage 5, and a recommended 6-year amortization for Vintage 6.

<u>Accounting Treatment forExpiring Vintages</u>

In reviewing the amortization schedules for each vintage, Staff noted that Vintages 1 and 2 will be fully amortized within three years of the conclusion of the current rate case and

Vintage 5 within four years. Once the vintages are fully amortized, KCPL will be collecting funds in rates for expenses it is no longer incurring. Staff recommends that once amortization of a vintage is complete, KCPL apply the funds that will continue to be collected through rates relative to the completed amortizations to the unrecovered amounts in the next vintage DSM program costs currently being deferred by KCPL's. The application of funds collected from expired Vintages will reduce the overall carrying costs incurred by KCPL's, which will reduce future rates resulting from deferred DSM costs, thereby providing a benefit to both KCPL's and the ratepayer.

In the event that all active DSM programs are ended or the total of expired amortization amounts exceed the costs deferred for Vintage 7, Staff recommends that the amounts collected in rates from all expired vintages be applied to the next vintage scheduled to expire soonest. This accounting treatment is appropriate since all six (6) existing vintages are nearly identical in nature except for the timing in which the DSM costs were incurred. Since the approval of KCPL's regulatory plan on July 28, 2005, KCPL's has been managing energy efficiency programs, demand response programs, and affordability programs. The type of programs included in the deferred DSM costs has not changed since 2005 and, therefore, Staff recommends that the funds collected for each vintage should not be earmarked for that particular vintage, but pooled to reimburse KCPL for the deferred costs expeditiously.

Staff Expert/Witness: Matthew R. Young

D. KCPL's MEEIA Filings Summary

KCPL filed its first MEEIA application on December 22, 2011, in File No. EO-2012-0008 and withdrew it on February 17, 2012. KCPL filed its second MEEIA application on January 7, 2014, in File No. EO-2014-0095 to implement twelve (12) demand-side programs. KCPL's requested Commission approval for the programs and asked for the authority to establish a demand-side programs investment mechanism ("DSIM"). The Commission approved the *Non-Unanimous Stipulation and Agreement Resolving Kansas City Power & Light Company's MEEIA Filing* with the effective date of June 15, 2014, and KCPL began implementation of its MEEIA programs and Demand-Side Investment Mechanism Rider (Schedule DSIM) on July 6, 2014. The 18-month plan includes a total budget of $19,175,842 for the 12 MEEIA Programs with 102,588,995kWh of total energy savings and 43,093 kW of total demand savings.

Staff Expert/Witness: Jason Huffman

E. Light Emitting Diode ("LED") Street and Area Lighting

In Staff's last KCPL Cost of Service Report, filed in Case No. ER-2012-0174, Staff recommended that KCPL complete the evaluations of its pilot projects' of Light Emitting Diode (LED) Street and Area Lighting ("SAL") systems, and no later than the end of calendar year 2012, file either a compliance LED lighting tariff, or a status report as to when it anticipates filing such a tariff. As part of the settlement of certain issues in Case No. ER-2010-0355, KCPL agreed during the February 4, 2011, on the record hearing to:

> ...file by the end of calendar year 2012 either a LED lighting tariff, or when [KCPL] anticipate[s] filing such LED lighting tariff. Also by the end of calendar year 2012, KCPL . . . shall file the results of its LED study, which shall include a review of potential LED lighting health issues.

As agreed upon in Case No. ER-2012-0174, KCPL filed its LED and SAL project status report with Staff on December 31, 2012. Further, KCPL continues to monitor the development of LED options within the roadway and area lighting sectors. As recently as March 2015, KCPL reported to Staff:

> "We have been reviewing and evaluating LED options, but are not yet ready to propose a tariff for this technology. We have made progress concerning the available LED models, finding what we believe are replacement fixtures for our various streetlight sizes. Our latest efforts have been focused on defining how to offer and deploy LEDs. We have identified alternatives but need to be certain how they might impact customers and the Company. We have a team that meets frequently to continue to move this initiative forward. We still expect that once the details have been worked out, our next step will be to review the plan with you in advance of any filing. "

Staff recommends that the Commission order KCPL to continue to study the cost-effectiveness of replacement of all or parts of existing company-owned street lights with LED lights. Staff also recommends that the Commission order KCPL no later than twelve (12) months following the Commission's Report and Order in this case, to file either proposed LED lighting tariff sheets or an update to the Commission on when it will file a proposed LED lighting tariff to replace existing company-owned street lights.

Staff Expert/Witness: Jason Huffman

F. Tariff Issues

1. <u>METERING: Billing Adjustments Charges</u>

Staff recommends the Commission approve KCPL's request for a billing adjustment for commercial entities because the changes would be consistent with regulation 4 CSR 240-13.025. 4 CSR 240-13.025.1.B states the following:

> (B) In the event of an undercharge, an adjustment shall be made for the entire period that the undercharge can be shown to have existed not to exceed twelve (12) monthly billing periods or four (4) quarterly billing periods, calculated from the date of discovery, inquiry or actual notification of the utility, whichever was first.

The proposed changes will bring the KCPL-MO jurisdiction under the same requirements of KCPL-Kansas jurisdiction and as GMO. Currently, the tariff language does not address the issue of billing adjustments for undercharges. The proposed language will allow back billing for slow meters for up to twelve billing periods. Consistent adjustment terms will provide customers consistent treatment and will make KCPL's internal processes more efficient.

Staff Expert/Witness: Byron M. Murray

2. <u>BILLING AND PAYMENT: Returned Check Charge Increase</u>

Staff recommends the Commission reject KCPL's request for the increase of the current return check charge. The only evidence provided by KCPL's to support the proposed increase above the current charge of thirty dollars ($30) is the direct testimony provided by Mr. Tim Rush in the 2006 rate case (ER-2006-0314). Page ten (10) of Mr. Tim Rush's testimony in that case states that increasing the fee from ten dollars ($10) to thirty dollars ($30) is in line with their actual cost of processing and collecting on a returned check. No current information has been provided KCPL that its actual cost of processing and collecting returned checks has increased since the 2006 case. Furthermore, KCPL does not state a specific dollar amount or percentage increase that the returned check charge should be increased. A spreadsheet of collected amounts of returned charges was provided but did not include supporting documentation to justify KCPL's requested increase. KCPL did not provide requested documentation used to determine the amount of the returned check charge. Data Request No. 0298 asked for documentation supporting the increase for the two charges.

In response to Data Request No. 0296, KCPL stated the following: "KCP&L will need clarification on what is considered a billing adjustment. Return check/collection fees are created and billed through an adjustment in CIS." The response was provided by Mr. Paul Myers. KCPL requested clarification of what is considered a billing adjustment.

Staff Expert/Witness: Byron M. Murray

3. BILLING AND PAYMENT: Collection Charge Fee (In-Field)

Staff recommends the Commission reject the requested increase in the collection charge for in-field payments. KCPL's current collection charge was established as part of the its 2010 rate case (Case No. ER-2010-0355). The charge was based on direct testimony provided by KCPL witness Tim Rush. Staff filed a data request in this case (Data Request No. 0557), which inquired about the justification of the requested increase in the charge. All of the documentation provided by KCPL is from the 2010 rate case and no current information on the costs of providing the in-field service was provided as requested by Staff.

KCPL's only stated rational for increasing the collection charge is to reduce the number of customers attempting to avoid disconnection of service by remitting payment in the field. KCPL argues that an increase in the collection fee will incent chronically slow payers to use no-fee payment options in place of delaying payment of their bills at the time of disconnection. KCPL's Response to Data Request No. 0298 explains that the methodology used to value the in-field collection is based on the time associated with the activity. Their costs provided in the 2010 rate case totaled and aligned with a twenty-five dollar ($25) in-field collection charge. KCPL did not provide any updated studies or analysis showing an increase in the cost for the collection of outstanding payments in the field therefore; there is no justification for an increase in the collection charge. There was no analysis provided as to the sufficiency or insufficiency of the current twenty dollar ($20) collection charge on reducing late, last minute payments by the chronically slow payers.

Staff Expert/Witness: Byron M. Murray

G. KCPL Smart Grid Update

This section provides information on the history and status of KCPL's Smart Grid deployment and does not address any particular revenue requirement in this rate case. KCPL has over the past several years invested in upgrading its existing electrical grid infrastructure with several Smart Grid components that includes phase measurement units, faulted circuit indicators, smart line capacitors and switches as described in Schedule RSG-1. The final phases of the Smart Grid demonstration project were completed at the end of 2014 and final reports are scheduled to be issued in the second quarter of this year.[161] KCPL is in the initial phase of the planned partial replacement of its existing 500,000 Automated Meter Reading (AMR) meters with approximately 250,000 Advanced Metering Infrastructure (AMI) meters in 2015.[162] To support the AMI deployment, KCPL has installed 27 Collectors, 1707 Concentrators/Routers and an additional AMR radio to collect data from both the AMR and AMI meters.[163] The Company also announced in a press release earlier this year its plans to install and operate over 1,000 electric vehicle charging stations as part of its Clean Charge Network.

The KCPL Smart Grid Demonstration Project (Project) is included in the Department of Energy (DOE) and Electric Power Research Institute (EPRI) demonstration programs.[164] The Project is located in an economically challenged area of Kansas City, Missouri. The Project's goal is to deliver benefits to the immediate targeted end-users and provide valuable experience and lessons for future applications. Project funding consists of approximately $58.2 million spent from 2010 through 2014, of which $25.2 million (43%) is KCPL-funded, $9 million (16%) is partner/vendor-funded and $23.9 million (41%) is federally-funded through the American Recovery & Reinvestment Act (ARRA).[165] KCPL vendor partners consist of Siemens Energy, Inc., Open Access Technology, Inc. (OATI), Landis&Gyr, Tendril, Exergonix, EPRI, Intergraph, and eMeter/Siemens.[166]

The Project is an end-to-end Smart Grid that includes AMI, renewable generation, energy storage resources, leading edge substation and distribution automation and control, energy management interfaces, and innovative customer programs to include time of use (TOU) rate

[161] KCPL Smart Grid Demonstration Project Missouri Stakeholder update November 21, 2014.
[162] KCPL response to MOPSC Data Request No. 0218.
[163] KCPL response to MOPSC Data Request No. 0217.
[164] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.
[165] KCPL Smart Grid Demonstration Project Missouri Stakeholder update November 21, 2014.
[166] Interim Technology Performance Report submitted to the Department of Energy, December 31, 2013.

structures and demand response (DR). The Project will focus on the area served by KCPL's Midtown Substation across 2 square miles, impacting about 14,000 commercial and residential customers across ten circuits with total electric demand of 69.5 Mega Volt Amperes (MVA). The Smart Grid Project includes over 25 stakeholder groups including: Mid-America Regional Council (MARC), Missouri Electric Cooperative (MEC), Missouri Gas Energy (MGE), University of Missouri at Kansas City (UMKC), the Missouri Public Service Commission, The Kansas Corporation Commission, the City of Kansas City, Missouri and several local neighborhood groups.[167]

Within the Smart Grid Project boundaries lies the Green Impact Zone project, a 150 square block area of inner-city neighborhoods in Kansas City. The primary goal of the Green Impact Zone Project is to help transform distressed urban neighborhoods into sustainable communities.[168] The Project is based upon the guidance found in the proposed National Institute of Standards (NIST) interim Smart Grid Interoperability Standards Roadmap, the EPRI IntelliGrid Architecture and the GridWise Architectural Council recommendations.[169]

The primary, overall focus for the Project is to implement next-generation, end-to-end Smart Grid components that will include Distributed Energy Resources (DER), enhanced customer facing technologies, and a distributed-hierarchical grid control system that includes the following key elements:[170]

- Upgrade the Midtown Substation to create a next generation "Smart Substation;" with multiple distribution circuits that have a variety of feeder-based instrumentation and control devices for monitoring and control, and a Grid management infrastructure to support the upgraded grid, back office and substation requirements (see detailed description below);

- Smart Meters (14,000) with AMI installed at all customer sites to provide consumers with enhanced information on energy use and the opportunity to utilize residential TOU rate structures.

- Integration of distributed generation that includes an Exergonix 1 MW Superior Lithium battery storage system that was delivered and installed at the Midtown Substation in April 2013. The final operational test was conducted successfully in

[167] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.
[168] KCP KCPL Green Impact Zone Smart Grid Demonstration submitted to the DOE, August 26, 2009.
[169] Ibid.
[170] Ibid.

October of 2014, which consisted of providing power to the KCPL Innovation Park.[171] This differed from the original plan of providing power to the entire feeder connected to the battery due to a vendor control system malfunction that was subsequently corrected prior to the test;[172]

- Distributed roof-top solar photovoltaic systems that include installations at Paseo High School, Blue Hills Community Center, UMKC Student Union and Flarsheim Hall, Midwest Research Institute, KCPL Midtown/SmartGrid battery site, KCPL Crosstown Substation, Project Living Proof demonstration house and City of Kansas City, MO Swope Building;[173]

- Distributed electrical vehicle charging stations. Currently the Company has 20 distributed vehicle charging stations that accommodate Plug in Hybrid Electrical Vehicles (PHEV) at various locations and is monitoring usage patterns. The Company announced in a press release earlier this year plans to install and operate over 1,000 electric vehicle charging stations as part of its Clean Charge Network;

- The Smart Grid Innovation Park that contains the Exergonix battery energy storage system (BESS), solar panel electrical generation, electrical vehicle charging stations, operating system displays and an educational Kiosk.[174]

- Demonstration House (Project Living Proof) that is located at 917 Emanuel Cleaver II Blvd and is open to the public. KCPL has partnered with the Metropolitan Energy Center to show case products and technology applications that include smart hyper-efficient washers, dryers and water heaters, roof top solar, battery storage and associated DC to AC inverter, alternative heating and cooling equipment, an electrical vehicle charging station, sustainable landscaping, energy efficiency measures, and devices and web based tools utilized by customers in the Smart Grid demonstration project as described below.

Consumers within the Smart Grid demonstration project boundaries were offered a wide range of products and services as follows[175]:

- 2,040 customers with internet access have taken advantage of KCPL's personalized web page via a web portal ("MySmart Portal") to view their real-time energy usage [176];

[171] KCPL Smart Grid Demonstration Project Missouri Stakeholder update November 21, 2014.
[172] Ibid.
[173] Ibid.
[174] KCPL Smart Grid Demonstration Project Missouri Stakeholder update July 26, 2013.
[175] KCPL Smart Grid Demonstration Project Missouri Stakeholder update November 21, 2014.
[176] Ibid.

- 1,231 residential and commercial customers have in home/business energy usage displays ("MySmart Display") that indicate real-time information and demand response thermostats ("MySmart Thermostat")[177];

- All residential and commercial customers have access to an Energy Management System (EMS);

- TOU program. This voluntary program charges customers a rate that is dependent on the time of day and is designed to reflect higher and lower rates during the day that coincide with the wholesale electric market. During the summer of 2012, 68 residential customers participated in the TOU program with 40 customers saving and 28 customers not saving money on their electric bill as determined by computing what their bill would have been had they been on a fixed rate charge.[178] Customers participated on a "no-risk" basis in that they were guaranteed that their bill would be no greater than it would have been had they been on a fixed rate plan.

- DR Plan. Testing of this plan occurred during 4 events in July and 1 event in August of 2014, taking place between 4 and 6 pm, and consisting of raising the temperature of the MySmart Thermostat by 3 degrees during the first hour of the event. Target participation rates ranged between 75-82 percent with actual participation rate results ranging between 12-71 percent. The lower participation rates were attributed to an error in the Tendril software code that improved to 71 percent after the code fix.[179]

Staff Expert/Witness: Randy S. Gross

1. Midtown Substation[180]

The Midtown Substation is located at 47th and Forest and is one of the oldest substations, built in the early 1960s. The new substation upgrades the existing substation controls as well as the monitoring and older communication protocols. Schedule RSG-1 includes descriptions of the upgrades for controls, automation and monitoring and additional Smart Grid components outside the substation.

Staff Expert/Witness: Randy S. Gross

[177] Ibid.
[178] KCPL Smart Grid Demonstration Project Missouri Stakeholder update November 21, 2014.
[179] Ibid.
[180] https://www kcpl.com/troost/051308_mtgSumm.pdf & http://tdworld.com/distribution/wired-success.

H. Renewable Energy Standard

1. Background Information

The Missouri Renewable Energy Standard ("RES")[181] was enacted as a voter initiative petition in November 2008. Provisions of the resulting statute and regulations require KCPL (and the other investor-owned utilities) to meet certain requirements regarding the use of renewable energy while not exceeding the one percent (1%) retail rate impact limit. The RES requires KCPL to provide a rebate ($2.00 per installed watt)[182] to its retail customers for installation of solar electric systems on their premises. KCPL filed an application requesting suspension of its solar rebate payments on September 10, 2013, in Case No. ET-2014-0071. The Commission approved a non-unanimous stipulation and agreement[183], by an order effective October 30, 2013, which set a specified level of $36.5 million for solar rebate payments incurred subsequent to August 31, 2012. Also in the non-unanimous stipulation and agreement, KCPL agreed that recovery of RES compliance costs related to solar rebate payments would not exceed one percent (1%) of the Commission-determined annual revenue requirement in the proceeding. Staff continues to review the RES compliance costs including solar rebate payments.

For calendar years 2011 through 2013, the RES requires KCPL to generate or purchase two percent (2%) of its retail sales using renewable energy resources. For calendar year 2014 the renewable energy requirement increases to five percent (5%) of its retail sales[184]. KCPL must derive two percent (2%) of the renewable energy requirement from solar energy[185]. RECs can be banked for three (3) years and utilized for future compliance purposes[186]. KCPL files annually a RES Compliance Plan and RES Compliance Report[187]. Each RES Compliance Plan provides information regarding the utility's plan for the current calendar year and the subsequent two (2) calendar years. The RES Compliance Report is a status report on the utility's compliance for the preceding calendar year. For the 2013 calendar year, KCPL utilized renewable energy and RECs from Spearville I for the non-solar requirement and retired S-RECs from various third-party

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181 Mo. Rev. Stat. § 393.1020 (2000).
182 For systems becoming operational on or before June 30, 2014.
183 Filed on October 3, 2013 in ET-2014-0071.
184 Mo. Rev. Stat. § 393.1030 .1(1) (2000).
185 Mo. Rev. Stat. § 393.1030.1 (2000).
186 "An unused credit may exist for up to three years from the date of its creation." Mo. Rev. Stat. § 393.1030.2 (2000).
187 Ameren Missouri filed its RES Plan for 2014-2016 and its RES Report for calendar year 2013 in EO-2014-0291.

brokers for the solar requirement[188]. KCPL's compliance report for calendar year 2014 is due on April 15, 2015.

Staff Expert/Witness: Claire M. Eubanks

2. <u>Renewable Energy Costs</u>

Pursuant to 4 CSR 240-20.100 (6)(D), the RES rule provides a recovery option for compliance costs. The rule provides that KCPL may:

> ...recover RES compliance costs without the use of a RESRAM through rates established in a general rate proceeding. In the interval between general rate proceedings, the electric utility may defer the costs in a regulatory asset account and monthly calculate a carrying charge on the balance in that regulatory asset account equal to its short-term cost of borrowing. All questions pertaining to rate recovery of the RES compliance costs in a subsequent general rate proceeding will be reserved to that proceeding, including the prudence of the costs for which rate recovery is sought and the period of time over which any costs allowed rate recovery will be amortized.

On April 19, 2012, the Commission authorized KCPL's use of an accounting authority order in Case No. EU-2012-0131, to:

> (a) record all incremental operating expenses associated with the cost of solar rebates, the cost to purchase renewable energy credits, the cost of the standard offer and other related costs incurred as a result of compliance with Missouri's Renewable Energy Standard Law in USOA Account 182; (b) include carrying costs based on the Compan[y's] short term debt rate on the balances in those regulatory assets; and (c) defer such amounts in a separate regulatory asset with the disposition to be determined in the Compan[y's] next general rate cases.[189]

In Case No. ER-2012-0174, a regulatory asset was established for costs incurred through August 31, 2012, and recovery of those costs was set for three (3) years. The regulatory asset defined in that case is labeled Vintage 1 and is scheduled to be completed in January, 2016. Similar to Staff's recommended treatment of other expiring amortizations, Staff recommends that once the amortization of Vintage 1 is complete, KCPL should apply the funds that will continue to be collected in rates for the amortization of Vintage 1 to the current deferred RES

[188] EO-2014-0289, *Staff Report and Conclusion on Kansas City Power & Light Company's 2013 Renewable Energy Standard Compliance Report*, p. 4.
[189] File No. EU-2012-0131, *Order Approving and Incorporating Stipulation and Agreement*, p. 2.

program costs or to the unamortized balance of Vintage 2. The application of funds collected from expired Vintages will reduce the overall carrying costs incurred by the Company, which reduces the future rates resulting from deferred DSM costs, thereby providing a benefit to both the Company and the ratepayer.

In Adjustment E-182.1, Staff has included deferred RES costs (Vintage 2) incurred through December 31, 2014 with the recovery period set at six (6) years. Staff continues to have discussions with the Company concerning the level of RES costs through December 31, 2014. As part of its True-Up audit, Staff will continue to examine RES costs through May 30, 2015, and make additional adjustments as needed to the level for inclusion in permanent rates.

Staff Expert/Witness: Matthew R. Young

XVI. La Cygne Environmental Construction Project Continuation of Construction Accounting

On June 12, 2014 KCPL filed an application for an accounting authority order to defer certain costs related to the accounting treatment used for construction of the environmental upgrades at its La Cygne Generating Station. KCPL's AAO sought approval for several separate accounting treatments involving the La Cygne project. First, KCPL seeks to defer the impact on its books of recording depreciation expense associated with the La Cygne project from the time construction is completed to when KCPL starts to recover the La Cygne project's capital costs through rates set in the current rate case, expected to be September 29, 2015. Second, KCPL proposed to defer the impact of inclusion of the La Cygne project in KCPL's rate base once the project is in-service by recording carrying charges on the La Cygne project investment from the time construction is completed to when KCPL starts to recover the La Cygne project's capital costs through rates set in the current rate case. This accrual is referred to as "continuation of construction accounting," or, further abbreviated, "construction accounting." KCPL's application was docketed as Case No. EU-2014-0255.

At present, the environmental upgrades of La Cygne Unit 2 are expected to be completed in late March or April 2015, and the environmental upgrades of La Cygne Unit 1 are expected to complete by May 31, 2015.

Construction accounting is the deferral of treatment on a utility's books when an asset is completed and moved from construction work-in-progress (CWIP) to plant-in-service.

Construction accounting defers the start of depreciation and continues the use of Allowance for Funds Used During Construction ("AFUDC") even though, under the FERC Uniform System of Accounts ("USOA"), the completed construction – now plant-in-service—is no longer eligible for continued accrual of AFUDC. Under USOA treatment, depreciation expense starts the month that the equipment goes into service. Construction accounting deferral treatment effectively delays when the depreciation starts and allows continued AFUDC.

In the case of the construction accounting for the La Cygne Units 1 and 2 environmental projects, KCPL requested the Commission authorize the use this deferral mechanism in Case No. EU-2014-0255 to accrue a regulatory asset equal to the depreciation expense and carrying costs for the Missouri jurisdictional portion of this investment. This is for a period after the new investment is in-service, but prior to when the new investment will be included in KCPL's rate base in this case. When the construction of the La Cygne Units 1 and 2 environmental upgrades is completed, the USOA requires that AFUDC stop and depreciation expense start in the month of the completion of the installation of the equipment. KCPL's request to defer the costs relating to AFUDC and depreciation expense until when new rates determined by the Commission in this case go into effect. This deferral treatment would go through the effective date of rates in this case under KCPL's proposal, which would be the only item currently proposed to be taken out beyond the May 31, 2015, true-up ordered in this case.

On December 15th, 2014, KCPL and Staff filed their *Second Non-Unanimous Stipulation and Agreement* ("La Cygne 2nd Stipulation"). This agreement was essentially to consolidate the accounting authority order application with the 2015 rate case filed by KCPL on October 30, 2015. All rate recovery, if any, for the construction accounting treatment was to be addressed in the current rate case. The Commission approved the stipulation effective January 17, 2015, and ordered the following:

> 2. KCP&L is authorized to continue using construction accounting for the La Cygne Environmental Project for the period of time between when the project becomes operational and when rate recovery begins for the associated costs.
>
> 3. KCP&L is authorized to defer and record as a regulatory asset 1) depreciation expense that would otherwise be record [sic] on the company's income statement when the La Cygne Environmental Project becomes operational, and 2) carrying costs (equivalent of AFUDC recorded during construction work in

> progress in the last month before La Cygne Unit 2 and common plant become operational) that would otherwise cease to be recorded when the La Cygne Environmental Project becomes operational.
>
> 4. The base La Cygne Environmental Project costs on which carrying costs are calculated for deferral purposes shall not increase after the amount determined at the true-up in File No. ER-2014-0370, and no additional deferrals shall be recorded for the La Cygne Environmental Project after the effective date of rates in File No. ER-2014-0370.
>
> 5. Nothing in this order shall be considered a Commission ratemaking determination regarding the La Cygne Environmental Project construction accounting deferrals.

As of the December 31, 2014, end of the update period, there are no La Cygne construction accounting deferrals. The environmental equipment at La Cygne 2 is expected to become in-service in the early second quarter of 2015 and the environmental equipment at La Cygne Unit 1 is expected to become in-service on or before June 1, 2015. Therefore, Staff has made no adjustment involving La Cygne construction accounting accruals in its direct case.

Staff does not recommend direct rate recovery of any La Cygne deferrals be approved. The Commission authorized deferrals to be recorded to KCPL's books and records. The Commission stated specifically in that authorization, "Nothing in this order shall be considered a Commission ratemaking determination regarding the La Cygne Environmental Project construction accounting deferrals."

The cost of the La Cygne environmental construction project does not rise to the level of the cost of other KCPL construction projects for which KCPL has received construction accounting treatment from this Commission in the past. Staff does not believe KCPL's request meets the Commission's prior standard for accounting authority orders being associated with events that are extraordinary, unusual, and infrequent. The expenses KCPL seeks recovery of are also not non-recurring. Although the magnitude of the La Cygne environmental construction project may be higher than some of the other KCPL construction projects, KCPL, as a vertically integrated electric utility, is constantly constructing significant assets. In that respect, the La Cygne environmental construction project cannot be considered "extraordinary."

However, if the Commission believes it is necessary to allow KCPL construction accounting treatment for the La Cygne Units 1 and 2 environmental upgrades, Staff believes there are other considerations that must be included as part of the calculation for any La Cygne deferrals included in the 2015 rate case. Those considerations include:

> 1) Offset the base on which the carrying costs are calculated by the additional non-environmental La Cygne depreciation reserve from the true-up date through the effective date of rates;
>
> 2) Offset the base on which carrying costs are calculated by the monthly depreciation expense deferral recorded to the regulatory asset;
>
> 3) Offset the base on which carrying costs are calculated by the accumulated deferred income taxes created by the La Cygne environmental plant;
>
> 4) Offset the base on which carrying costs are calculated by the accumulated deferred income taxes created by the monthly regulatory asset deferral;
>
> 5) Use actual depreciation and carrying costs based on the actual unadjusted Allowance for Funds Used During Construction (AFUDC) rate, less Staff's adjustment to the equity rate;
>
> 6) For the calculation of the AFUDC rate, a 250 basis point (2.50%) reduction to the authorized ROE used in the calculation should be assumed in the cost rate of common equity component of the AFUDC rate;
>
> 7) No additions to the base on which carrying costs or depreciation are calculated after the true-up in Case No. ER-2014-0370 (agreed to in the La Cygne 2nd Stipulation and ordered by the Commission in Case No. EU-2014-0255); and
>
> 8) No additional deferrals after the effective date of rates in Case No. ER-2014-0370 (agreed to in the La Cygne 2nd Stipulation and ordered by the Commission in Case No. EU-2014-0255).

Staff Expert/Witness: Keith Majors

XVII. Transition Cost Recovery Mechanism

A. Acquisition Transition Cost Recovery

On April 4, 2007, Great Plains, KCPL and Aquila sought authority for a series of transactions whereby Aquila would become a direct, wholly-owned subsidiary of Great Plains. On July 1, 2008, in Case No. EM-2007-0374 ("Acquisition Case"), the Commission granted that authority. On July 14, 2008 Great Plains completed the acquisition.

In the Commission's *Report and Order* in that case, at page 282 of the Slip Opinion, in ordered paragraph 6(c), the Commission included the following condition:

> c. Great Plains Energy, Incorporated, Kansas City Power & Light Company and Aquila, Inc., shall, upon closure of the authorized transactions, implement a synergy savings tracking mechanism as described by the Applicants, and in the body of this order, utilizing a base year of 2006;

Re Great Plains Energy Inc., et al., Case No. EM-2007-0374, *Report and Order*, 17 Mo.P.S.C.3d 338, 581 (2008). The Commission found potential for significant savings from the acquisition, and supported Great Plains, KCPL and Aquila recovering the costs incurred in combining the operations of KCPL and Aquila. These costs are referred to as "transition costs" and include non-executive severance costs for employees terminated, facilities integration costs, and incremental third-party and other non-labor expenses incurred as a result of the acquisition. The Commission also addressed transaction costs, such as investment banking fees, legal costs preparing legal documents to complete the acquisition. In the Acquisition Case Report and Order where it presented its "Final Conclusions Regarding Transaction and Transition Cost Recovery," on page 241 of the Slip Opinion, the Commission stated:

> Substantial and competent evidence in the record as a whole supports the conclusions that: (1) the Applicants' calculation of transaction and transition costs are accurate and reasonable; (2) in this instance, establishing a mechanism to allow recovery of the transaction costs of the merger would have the same effect of artificially inflating rate base in the same way as allowing recovery of an acquisition premium; and (3) the uncontested recovery of transition costs is appropriate and justified. The Commission further concludes that it is not a detriment to the public interest to deny recovery of the transaction costs associated with the merger and not a detriment to the public interest to allow recovery of transition costs of the merger.
>
> If the Commission determines that it will approve the merger when it performs its balancing test..., the Commission will authorize KCPL and Aquila to defer transition costs to be amortized over five years.[930]

In footnote 930 referenced above the Commission stated:

> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCPL and Aquila demonstrate that the synergy savings

> exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases.
> *Id.* at 548.

In the 2010 Rate Case (*Re Kansas City Power & Light Co.*, File No. ER-2010-355, *Report and Order* (2010), the Commission determined the appropriate amount of acquisition transition costs to include in KCPL's rates. The Commission ordered recovery of the transition costs over five years beginning with the effective date of rates in the 2010 Rate Case. KCPL and GMO have not deferred any additional transition costs after December 31, 2010. Below are the total unamortized transition costs, the amount of amortization at December 31, 2014, and the balance at December 31, 2014:

Acquisition Transition Costs at December 31, 2014	
KCPL – MO	
Deferred Transition Costs	$19,344,018
Amortized Amount	$14,185,613
Balance At December 31, 2014	$5,158,405
GMO – MPS	
Total Deferred Transition Costs	$17,727,367
Amortized Amount	$12,468,248
Balance At December 31, 2014	$5,259,119
GMO – L&P	
Total Deferred Transition Costs	$4,452,471
Amortized Amount	$3,131,571
Balance At December 31, 2014	$1,320,900
Summary All Missouri Jurisdictions	
Total Deferred Transition Costs	$41,523,856
Total Amortized Amount to Expense	$29,785,433
Balance At December 31, 2014	$11,738,423

Directly through the cost of service through rates, KCPL and GMO will recover $29.8 million in transition costs through the December 31, 2014 update in this case. The total unamortized balance for all jurisdictions is $11.7 million at December 2014 (see above table).

KCPL's annual amortization of transition costs is $3,868,804. With the balance of the amortization at December 31, 2014 of $5,158,405 (see table above) and $3,546,403 at the May 31, 2015 true-up cutoff date, KCPL amortization will expire in April 2016. If the amortization is allowed to be reflected in KCPL's rates in this case, KCPL will over-accrue (over collect) in rates after that date.

In the 2010 Rate Case *Report and Order* Findings of Fact at page 151 of the Slip Opinion, the Commission found:

> 441. In Missouri, it is well established that there is a lag between when a cost or revenue is incurred and when that cost or revenue is reflected in rates. This is known as regulatory lag. [footnote omitted]
>
> 442. As a result of regulatory lag, if a utility experiences a cost decrease, there is a lag in time until that reduced cost is reflected in rates. During that lag, the Company shareholders reap, in the form of increased earnings, the entirety of the benefit associated with reduced costs. The Company shareholders also reap, in the form of decreased earnings, the entirety of the loss associated with increased costs.

The Commission also recapped its Acquisition Case *Report and Order* by restating footnote 930 of that *Report and Order* in Paragraph 444 of the Findings of Fact in the 2010 Rate Case *Report and Order*.

> 444. The Commission qualified its authorization by stating that, "The Commission will give consideration to ...[the transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCP&L and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases." [footnote omitted] The Commission contemplated that the recovery would only happen if the synergy savings were greater than the costs to achieve those savings. [footnote omitted; emphasis added]

The Commission, in both the Acquisition *Report and Order*, and in its 2010 Case *Report and Order*, relied on the Synergy Savings Tracking Model that Acquisition Case *Report and Order* ordered. In Findings of Fact 449 and 451 at page 152 of the Slip Opinion in the 2010 Case *Report and Order*, the Commission related as follows:

> 449. The Companies developed and maintained a Synergy Tracking Model which demonstrated that the merger synergy savings for non-fuel operations and maintenance expense exceed the amortization of merger transition costs. [footnote omitted]
>
> *　　　*　　　*　　　*
>
> 451. Staff performed an analysis of both the Commission-ordered synergy savings tracking model and KCP&L created synergy project charter

> database. Staff's analysis showed that the amount of synergies in the synergy project database exceeded those in the Commission-ordered tracking system. [footnote omitted]

When reading the above decisions, the Commission relied on, in part, the Commission-Ordered Synergy Savings Tracking Model. However, in response to Staff Data Request No. 0195.1 in Case No. ER-2012-0174 (2012 Rate Case), KCPL stated:

> KCP&L has not maintained the synergy tracking model that the Commission ordered to demonstrate that amortization of transition costs should begin. KCP&L has continued to track synergies internally using the charter database provided in the response to data request 196 in the current case (ER-2012-0174).

In response to Staff Data Request No. 0229 in this case, KCPL confirmed that it has not used the Commission Ordered Synergy Savings Tracking Model through the current time period. Although KCPL received the amortizations reflected in rates in the 2010 Rate Case based largely on reliance on the tracking system to demonstrate acquisition synergy savings, KCPL simply disregarded the Commission's expectations to continue tracking synergy savings beyond the 2010 rate case.

The relevance of an updated Commission Ordered Synergy Savings Tracking Model lies in what the model was designed to demonstrate. In the 2010 Rate Case and the previous KCPL rate case (Case No. ER-2009-0089), the model compared the adjusted base year of non-fuel operations and maintenance (non-fuel O&M) of standalone KCPL and GMO (then Aquila) operations in calendar year 2006 to the combined KCPL and GMO operations of calendar year 2009, the test year in the 2010 Rate Case. The model demonstrated annual synergies of $48.5 million. The Commission relied on this model, as contemplated in the Acquisition Case *Report and Order*, to consider transition cost recovery in future rate cases. The Commission specifically relied on the results of this model in its 2010 Case Report and Order in Finding of Fact No. 455: "The synergy savings exceed the level of the amortized costs."

The Commission reiterated in the 2010 Case *Report and Order* Conclusions of Law, Slip Opinion, p. 155, its reliance on the Commission-Ordered Synergy Savings Tracking Model as follows:

> 41. ...[T]he Commission reserved consideration of recovery of the transition costs when it said:

> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCP&L and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases. [Footnotes omitted]

KCPL has not maintained the Commission Ordered Synergy Savings Tracking Model. In the 2010 KCPL Case, the Commission relied on, among other things, this very model in its decision to amortize the transition costs and include the annual amortization amounts in the revenue requirements of KCPL and GMO. While KCPL has maintained its Synergy Charter Tracking Database for recording cumulative synergy savings, without the Commission Ordered Synergy Savings Tracking Model, Staff cannot determine whether the annual synergy savings, from an adjusted 2006 base year compared to the Commission-ordered test year in this case ending March 31, 2014, exceed the amount of the amortized transition costs.

B. Administrative and General (A&G) Expenses

1. <u>Regional Electric Utility Comparison</u>

Although the Staff cannot rely on the Commission Ordered Synergy Savings Tracking Model for its analysis, as it has not been maintained by KCPL, there is evidence that KCPL's administrative and general (A&G) expenses continue to increase and are the highest per average customer, third highest per megawatt hour sold, and highest per dollar of operating revenue of all the electric utilities this Commission rate regulates, and Westar. Staff's analysis used information directly from the individual utilities' FERC Form 1, their Annual Reports to the Commission, and information from the Westar Energy, Inc. ("Westar") FERC Form 1. Westar was included in Staff's analysis because it share's three baseload units with KCPL and is a vertically integrated electric utility that borders KCPL's service territory.

Staff presented a similar analysis in KCPL's 2010 Rate Case, and the Commission found in its Report and Order, Slip Opinion, page 154:

> 458. Staff did an analysis of the Companies' Administrative & General (A&G) expenses and other electric utilities in the region. [footnote omitted] Staff's analysis indicates that on a combined company basis, KCP&L and GMO have the highest A&G expenses per customer, per megawatt hour sold and per dollar of operating revenue. [footnote omitted]

Staff also updated and presented a similar analysis and conclusion about the A&G expense in the 2012 Rate Case

As can be seen below, KCPL and GMO's Administrative & General expenses remain pervasively high. The tables below are Staff's analysis through calendar 2013 (the last full year available) and calendar year 2011 (from the last rate case):

2013 Administrative & General (A&G) Expenses per Customer

Calendar Year 2013	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$44,699,513	$251,903,994	$97,745,567	$74,536,767	**$155,757,596**	$230,294,363
Average Number of Customers	168,080	1,197,298	373,151	314,937	**514,843**	829,780
A&G Cost per Customer	$265.94	$210.39	$261.95	$236.67	**$302.53** **Highest**	$277.54

2011 A&G Expenses per Customer

Calendar Year 2011	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$36,912,783	$275,200,772	$94,161,548	$70,505,022	**$173,703,809**	$244,208,831
Average Number of Customers	166,236	1,190,483	369,168	312,716	**512,125**	824,841
A&G Cost per Customer	$222.05	$231.17	$255.06	$225.46	**$339.18** **Highest**	$296.07

2013 A&G Expenses per Megawatt Hour Sold

Calendar Year 2013	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$44,699,513	$251,903,994	$97,745,567	$74,536,767	**$155,757,596**	$230,294,363
Megawatt Hours Sold	5,620,276	43,158,374	17,484,374	8,413,828	**21,683,329**	30,097,157
A&G Cost Per MWH Sold	$7.95	$5.84	$5.59	$8.86	**$7.18**	$7.65

2011 A&G Expenses per Megawatt Hour Sold

Calendar Year 2011	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$36,912,783	$275,200,772	$94,161,548	$70,505,022	**$173,703,809**	$244,208,831
Megawatt Hours Sold	5,815,365	48,142,970	17,499,665	8,520,415	**20,374,582**	28,894,997
A&G Cost Per MWH Sold	$6.35	$5.72	$5.38	$8.27	**$8.53** **Highest**	$8.45

2013 A&G Expenses per Electric Operating Revenue

Calendar Year 2013	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$44,699,513	$251,903,994	$97,745,567	$74,536,767	**$155,757,596**	$230,294,363
Total Electric Operating Revenues	534,280,086	3,390,675,469	1,361,533,261	800,537,114	**1,671,422,009**	2,471,959,123
A&G Cost Per Electric Revenue Dollar	$0.0837	$0.0743	$0.0718	$0.0931	**$0.0932** **Highest**	$0.0932

2011 A&G Expenses per Electric Operating Revenue

Calendar Year 2011	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$36,912,783	$275,200,772	$94,161,548	$70,505,022	**$173,703,809**	$244,208,831
Total Electric Operating Revenues	522,506,506	3,226,611,565	1,240,125,727	759,742,827	**1,558,265,703**	2,318,008,530
A&G Cost Per Electric Revenue Dollar	$0.0706	$0.0853	$0.0759	$0.0928	**$0.1115** **Highest**	$0.1054

Five Year Analysis of FERC Form 1 Administrative & General Expenses

A&G Expenses per Customer

Company	2009	2010	2011	2012	2013
Empire	$170.09	$194.16	$222.05	$251.10	$265.94
Ameren Missouri	$211.03	$201.85	$231.17	$198.47	$210.39
Westar	$223.55	$252.38	$255.06	$265.45	$261.95
GMO	$214.65	$198.10	$225.46	$240.43	$236.67
KCPL	**$278.43**	**$298.54**	**$339.18**	**$298.63**	**$302.53**
Combined KCPL & GMO	$254.23	$260.45	$296.07	$276.55	$277.54

A&G Expenses per Megawatt Hour Sold

Company	2009	2010	2011	2012	2013
Empire	$5.28	$5.46	$6.35	$7.47	$7.95
Ameren Missouri	$5.11	$4.98	$5.72	$5.38	$5.84
Westar	$4.76	$5.17	$5.38	$5.79	$5.59
GMO	$8.26	$7.02	$8.27	$8.99	$8.86
KCPL	**$7.08**	**$7.10**	**$8.53**	**$6.97**	**$7.18**
Combined KCPL & GMO	$7.42	$7.07	$8.45	$7.53	$7.65

A&G Expenses per Electric Operating Revenue

Company	2009	2010	2011	2012	2013
Empire	$0.0660	$0.0678	$0.0706	$0.0825	$0.0837
Ameren Missouri	$0.0926	$0.0793	$0.0853	$0.0757	$0.0743
Westar	$0.0768	$0.0772	$0.0759	$0.0754	$0.0718
GMO	$0.1035	$0.0838	$0.0928	$0.0992	$0.0931
KCPL	**$0.1079**	**$0.1007**	**$0.1115**	**$0.0969**	**$0.0932**
Combined KCPL & GMO	$0.1064	$0.0952	$0.1054	$0.0977	$0.0932

In comparison to The Empire District Electric Company ("Empire"), Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri"), and Westar, KCPL and GMO combined have the highest A&G cost per customer, the third highest A&G cost per megawatt hour sold (GMO has the highest), and the highest A&G cost per dollar of electric revenue.

The result of the revised analysis is similar to that presented by Staff in the 2010 and 2012 Rate Cases. In addition, Staff compared the same utilities' A&G expenses to their respective overall O&M again using data from FERC Form 1:

A&G Expenses Compared to Total O&M Expense

Calendar Year 2013	Empire	Ameren Missouri	Westar	GMO	KCPL	Combined KCPL and GMO
A&G Expenses	$44,699,513	$251,903,994	$97,745,567	$74,536,767	**$155,757,596**	$230,294,363
Total O&M Expense	$310,360,096	$1,857,637,721	$779,531,805	$454,058,386	**$950,427,859**	$1,404,486,245
A&G as a % of Total O&M	14.40%	13.56%	12.54%	16.42%	**16.39%**	16.40%

Five Year A&G Expenses Compared to Total O&M Expense

Company	2009	2010	2011	2012	2013
Empire	10.31%	10.66%	11.54%	13.82%	14.40%
Ameren MO	15.65%	14.17%	14.66%	14.93%	13.56%
Westar	11.97%	12.80%	12.91%	13.27%	12.54%
GMO	14.84%	13.14%	14.50%	17.13%	16.42%
KCPL	**19.41%**	**19.08%**	**19.42%**	**17.17%**	**16.39%**
Combined KCPL & GMO	17.67%	16.88%	17.69%	17.16%	16.40%

As can be seen from the FERC Form 1 data, KCPL's cost structure had more A&G expenses as a portion of O&M for the last five years than other electric utilities in the region. In 2013, KCPL's A&G costs were almost 300 basis points higher than Ameren Missouri and almost 400 higher than Westar. While KCPL's A&G costs have declined in relationship to the other utilities in 2009 to 2011, they remain high compared to the other utilities in Staff's study.

Several conclusions can be drawn from the A&G analysis:

1) KCPL has the highest A&G expense per customer in 2013 and the highest among these utilities since Great Plain Energy's acquisition of Aquila.

2) KCPL has the third highest (behind GMO and Empire) A&G expense per MWH sold in 2013. From 2010-11, KCPL had the highest A&G expense per MWH sold.

3) KCPL has the highest A&G expense per dollar of operating revenue in 2013, and for the majority of 2009-2013. Put another way, for every dollar of revenue KCPL receives, a larger portion of that dollar goes to A&G expenses than the other utilities in the study.

4) In every year of the study, KCPL's cost structure had and continues to have a larger A&G expense in comparison to all other operating expenses (fuel, maintenance, etc.).

5) KCPL has higher A&G expenses than both utilities that own nuclear generation (Ameren Missouri and Westar). In some cases, Ameren Missouri and Westar have less A&G costs than non-nuclear utilities (Empire and GMO) in Staff's study. Consequently, KCPL's higher A&G expenses cannot be solely attributed to owning nuclear generation.

Although KCPL has not maintained the Commission Ordered Synergy Savings Tracking Model, it has maintained its Synergy Project Charter Tracking database. This database has been created by KCPL to internally track the cumulative savings it considers are a result of the acquisition of Aquila. The results of KCPL's current model as of June 30, 2013 are:

Synergy Project Charter Tracking Database Synergy Savings

Period	Regulated Savings	Corporate Savings
2008 Total	$20,614,612	$48,950,489
2009 Total	64,561,991	78,001,774
2010 Total	83,023,990	81,679,059
2011 Total	83,073,379	80,087,134
2012 Total	75,532,276	70,165,888
2013 Total	40,703,068	34,272,223
Total Cumulative Synergies	$367,509,317	$393,156,567

The KCPL Synergy database identifies two categories of synergy savings: "Regulated" savings and "Corporate" savings. Regulated savings are savings that relate to KCPL and GMO's regulated utility operations such as reduced headcounts, bulk purchase discounts, and fleet reductions. However, the amounts listed by year do not correspond to savings to ratepayers. "Corporate" savings are not enjoyed by ratepayers, as they are entirely company-paid costs (such as the excess interest on Aquila debt). KCPL has reaped an excess of savings over the transition costs of over $351 million [$393.2 million less $41.5 million of transition costs], or 846% of the total transition costs, with respect to the "Corporate Savings" alone. KCPL has sufficiently recovered the transition costs and no further collection from customers is warranted.

The cumulative totals of synergy savings show a clear distinction between the claimed "Corporate Savings" and "Regulated Savings," in light of the escalating A&G expenses. KCPL and GMO, while enjoying significant corporate retained benefits, have not flowed comparable regulated synergy savings to its regulated electric utility operations. During the five years post-acquisition, KCPL and GMO's ratepayers continue to pay rates premised upon some of the highest A&G expenses in the region.

KCPL launched its Organizational Realignment/Voluntary Separation Program ("ORVS") on March 10, 2011. The resulting reduction of 140 KCPL employees resulted in significant savings KCPL has and will retain through regulatory lag. Staff's analysis in the 2012 Rate Case demonstrated that KCPL recovered all of its ORVS-related costs and realized a net savings of approximately $13 million. These employee reductions are additional acquisition synergies that were realized less than three years subsequent to the acquisition of Aquila.

KCPL reduced its workforce after the completion of the 2012 Rate Case by a net of **___ ** employees. The annual salaries, wages, and benefits (with a 0.6 benefits adder) related to these employees are an annual savings to KCPL of ** __________ **, approximately ** __________ ** Missouri jurisdictional. These employees were included in the cost of service in the 2012 Rate Case, and KCPL retained savings related to those reductions through regulatory lag.

C. Recommendations

Staff does not recommend the continued amortization of transition costs through KCPL's cost of service. While KCPL has identified a cumulative total of $367,509,317 of Regulated Savings and $393,156,567 of Corporate Savings, it has not complied with the Commission's requirement to demonstrate that test year savings exceed the amortized transition costs. The Staff's latest figures indicate that KCPL and GMO will have received $29.8 million of amortized transition costs through rates through the December 31, 2014 update in this case.

In the Findings of Fact section of its *Report and Order* in the 2010 Rate Case concerning this issue, the Commission found the following at page 151 of its Slip Opinion:

> 441. In Missouri, it is well established that there is a lag between when a cost or revenue is incurred and when that cost or revenue is reflected in rates. This is known as regulatory lag. [footnote omitted]
>
> 442. As a result of regulatory lag, if a utility experiences a cost decrease, there is a lag in time until that reduced cost is reflected in rates. During that lag, the Company shareholders reap, in the form of increased earnings, the entirety of the benefit associated with reduced costs. The

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> Company shareholders also reap, in the form of decreased earnings, the entirety of the loss associated with increased costs.

In this case, the retained savings related to the 2011 and 2013 employee reductions are a result of regulatory lag, which the Commission recognized as a source of increased earnings as a result of reduced costs without a change in its retail rates.

In its 2010 Rate Case *Report and Order*, at pages 153-54 Slip Opinion, the Commission found that shareholders had retained significant synergy savings:

> 452. As of September 1, 2009, the shareholders of KCP&L and GMO had realized over $59.3 million in synergy savings. [footnote omitted]
>
> 453. As of June 30, 2010, the shareholders of KCP&L and GMO had realized approximately $121 million in retained synergy savings. [footnote omitted]
>
> 454. KCP&L and GMO project that total synergy savings through 2013 will be $344 million. [footnote omitted] Of that amount, KCP&L and GMO project that ratepayers will receive $150 million. [footnote omitted]

The amount of savings through September 1, 2009 alone of $59.3 million exceeded the amount of deferred transition costs KCPL and GMO requested for recovery of $41.5 million. In every year since 2009, KCPL and GMO continued to enjoy the benefits of the acquisition over and above the transition costs and enjoyed those benefits in advance of passing the savings to customers.

KCPL and GMO continue to realize new synergies related to the acquisition of Aquila. To the extent these synergies were not included in the test year of 2009 or the true-up cutoff of December 31, 2010 in the 2010 Rate Case, or in the test year, update, and true-up in the 2012 Rate Case, those synergies were not flowed to ratepayers and were retained by shareholders. These are in addition to $121 million of retained synergies the Commission identified in its 2010 *Report and Order*. Any acquisition savings realized by KCPL beyond those reflected in rates in the 2010 and 2012 rate cases are retained by KCPL and will continue to benefit KCPL until the effective date of rates in this case, expected late September 2015.

D. Amortization Period Relating to the Transition Costs

If the Commission authorizes the continued amortization of transition costs, Staff recommends a different amortization period than ordered in the 2010 Rate Case *Report and*

Order. In that *Report and Order*, the Commission found the following at page 153 of the Slip Opinion:

> 448. KCP&L and GMO began to retain synergy savings, in the form of reduced costs, immediately upon the closing of the acquisition. Given that KCP&L and GMO did not have its next rate case completed until September 1, 2009, the Great Plains shareholders retained the entirety of these synergy savings for that period of time. [footnote omitted]

Staff recommended, in its Cost of Service Report in both the 2009 and 2010 rate cases, that the amortization of transition costs should have begun at the effective date of rates of KCPL and GMO's first rate cases post-acquisition at September 1, 2009, effective dates of rates in Case No. ER-2009-0089. In Finding of Fact Paragraph 448 in the 2010 Rate Case *Report and Order* in Slip Opinion page 153, the Commission recognized that KCPL and GMO began retaining synergy savings immediately upon the closing of the acquisition. In consideration of this, Staff recommends that the assumed starting date for any transition cost amortization authorized in this case should be September 1, 2009, the effective date of the 2009 rate case (ER-2009-0089). However, again, it is Staff's position that the amortizations are concluded. KCPL has substantially recovered the transition costs to complete the acquisition of the former Aquila entity and should not receive any further rate recovery from its customers.

E. Summary

Staff recommends no additional amortization of transition costs in KCPL's cost of service. A full year of amortized transition costs is included in the test year cost of service. Staff Adjustments E-193.1 and E-200.4 remove the test year amount of the transition cost amortization from the cost of service.

Staff Expert/Witness: Keith Majors

XVIII. Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Support for Staff Cost of Capital Recommendation
-Zephania Marevangepo

Appendix 3 – Other Staff Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Alan J. Bax

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF KORY BOUSTEAD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kory Boustead, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Kory Boustead
Kory Boustead

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF NATELLE DIETRICH

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Natelle Dietrich, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Natelle Dietrich

Natelle Dietrich

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	) .)))	Case No. ER-2014-0370

AFFIDAVIT OF DANA E. EAVES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Dana E. Eaves, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Dana E. Eaves

Dana E. Eaves

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF CLAIRE M. EUBANKS, P.E.

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Claire M. Eubanks, P.E., of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Claire M Eubanks
Claire M. Eubanks, P.E.

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Cary G Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Cary G Featherstone

Cary G. Featherstone

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF RANDY S. GROSS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Randy S. Gross, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Randy S. Gross

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

V. William Harris

V. William Harris

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF JASON HUFFMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Jason Huffman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Jason Huffman

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF CHARLES R. HYNEMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Charles R. Hyneman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Ch. R. Hyn

Charles R. Hyneman

Subscribed and sworn to before me this 2nd day of April, 2015.

D. Suzie Mankin

Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF THOMAS M. IMHOFF

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Thomas M. Imhoff, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Thom M. Imhoff
Thomas M. Imhoff

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Robin Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Robin Kliethermes

Robin Kliethermes

Subscribed and sworn to before me this 2nd day of April, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF LISA A. KREMER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lisa A. Kremer, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lisa A. Kremer
Lisa A. Kremer

Subscribed and sworn to before me this 2nd day of April, 2015.

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OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Shawn E. Lange, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Shawn E Lange

Shawn E. Lange

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AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Karen Lyons, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Karen Lyons

Karen Lyons

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AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith Majors, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Keith Majors

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney

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AFFIDAVIT OF ZEPHANIA MAREVANGEPO

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Zephania Marevangepo, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Zephania Marevangepo

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF DERICK A. MILES, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Derick A. Miles, PE, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Derick A. Miles
Derick A. Miles, PE

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF JOEL A. MOLINA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Joel A. Molina, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Joel A. Molina

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF BYRON M. MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Byron M. Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Byron M. Murray

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Michael L. Stahlman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael L. Stahlman

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF SEOUNG JOUN WON, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoung Joun Won, PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won, PhD

Subscribed and sworn to before me this 2nd day of April, 2015.

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AFFIDAVIT OF MATTHEW R. YOUNG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Matthew R. Young, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Matt Young
Matthew R. Young

Subscribed and sworn to before me this 2nd day of April, 2015.

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