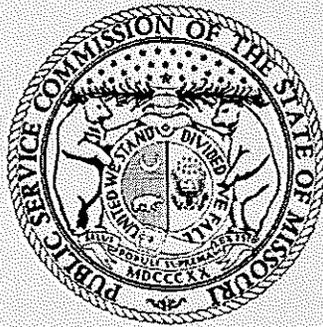


MISSOURI PUBLIC SERVICE COMMISSION

Filed
December 11, 2012
Data Center
Missouri Public
Service Commission

STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE



200 Exhibit No. 200-NP
Date 10/17/12 Reporter MM
File No. ER-2012-0174

KANSAS CITY POWER & LIGHT COMPANY
Great Plains Energy, Inc.

CASE NO. ER-2012-0174

*Jefferson City, Missouri
August 2, 2012*

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

NP

**TABLE OF CONTENTS OF
STAFF REVENUE REQUIREMENT
COST OF SERVICE REPORT
KANSAS CITY POWER & LIGHT COMPANY
CASE NO. ER-2012-0174**

1		
2		
3		
4		
5		
6		
7	I.	Background of Great Plains Energy and Kansas City Power & Light Company1
8	II.	Executive Summary3
9	III.	Kansas City Power and Light Company's Rate Case Filing5
10	A.	Test Year5
11	B.	True-up Case5
12	IV.	Economic Considerations6
13	V.	Kansas City Power & Light Company Electric Rates16
14	VI.	Rate of Return20
15	A.	Introduction20
16	B.	Analytical Parameters21
17	C.	Current Economic and Capital Market Conditions24
18	1.	Economic Conditions24
19	2.	Capital Market Conditions26
20	a.	Utility Debt Markets26
21	b.	Utility Equity Markets26
22	D.	GPE's, KCPL's and GMO's Operations28
23	E.	KCPL, GPE and GMO's Credit Ratings and Financing Activities29
24	1.	Credit Ratings29
25	2.	Financing Activities32
26	F.	Cost of Capital33
27	1.	Capital Structure33
28	2.	Embedded Cost of Debt and Preferred Stock34
29	3.	Cost of Common Equity37
30	a.	The Proxy Group37
31	b.	The Constant-growth DCF38
32	c.	The Multi-stage DCF41
33	G.	Tests of Reasonableness57

1	1.	The CAPM.....	57
2	2.	Other Tests.....	59
3	a.	The "Rule of Thumb".....	59
4	b.	Average Authorized Returns.....	59
5	c.	Equity Analysts.....	60
6	H.	Cost of Equity Compared to Returns on Equity.....	64
7	I.	Conclusion.....	65
8	VII.	Rate Base.....	66
9	A.	Plant-in-Service and Accumulated Depreciation Reserve.....	66
10	1.	Iatan Common Plant Transactions.....	68
11	B.	Material and Supplies.....	69
12	C.	Prepayments.....	70
13	D.	Cash Working Capital.....	71
14	E.	Fuel Inventories.....	72
15	1.	Coal Inventory.....	72
16	2.	Nuclear Inventory.....	73
17	3.	Oil and Fuel Additive Inventories.....	73
18	F.	Customer Deposits.....	74
19	G.	Customer Advances.....	74
20	H.	Iatan Construction Accounting Regulatory Assets.....	75
21	I.	2011 Missouri River Flood Incremental Non-Fuel Operations & Maintenance	
22		Expense.....	76
23	VIII.	Income Statement – Revenues.....	77
24	A.	Rate Revenues.....	77
25	1.	Introduction.....	77
26	2.	The Development of Rate Revenue.....	78
27	3.	Regulatory Adjustments to Billing Unit and Rate Revenue.....	78
28	a.	Weather Normalization.....	78
29	b.	Annualization for Rate Change.....	82
30	c.	365-Days Adjustment.....	83
31	B.	Customer Growth.....	84
32	C.	Additional Revenues from Customer Growth During the Update Period.....	84
33	D.	Customer Growth in Usage.....	85
34	E.	Large Customer Adjustments.....	86
35	1.	Special Contracts and Other Customer Discounts.....	87
36	F.	Off-System Sales.....	87
37	1.	FERC Account 447-Sales for Resale.....	87
38	2.	Firm Off-System Sales.....	88
39	3.	Non-Firm Off-System Sales.....	88
40	4.	Net Margin on Non-Firm OSS.....	88
41	5.	Adjustments to Non-Firm OSS.....	90
42	6.	FERC Wholesale Sales.....	91
43	G.	Excess Off-System Sales Margin Regulatory Liability.....	91
44	H.	SO2 Emissions Allowances.....	92
45	1.	Deferred Sales from SO2 Emissions Allowances.....	92

1	I.	Miscellaneous Revenues.....	93
2	2.	Late Payment Revenue (Forfeited Discount).....	93
3	J.	Other Revenue Accounts.....	93
4	K.	Removal of Gross Receipts Taxes from Test Year Revenues.....	94
5	L.	Regulatory Adjustments Result.....	94
6	IX.	Income Statement – Expenses.....	94
7	A.	Fuel and Purchased Power Expense.....	94
8	1.	Fixed Costs.....	95
9	2.	Fixed Adders.....	95
10	3.	Purchased Power – Energy.....	96
11	4.	Purchased Power – Capacity Charges.....	96
12	5.	Variable Costs.....	97
13	a.	Fuel Prices.....	97
14	b.	Coal Prices.....	97
15	c.	Natural Gas Prices.....	97
16	d.	Nuclear Fuel Prices.....	97
17	e.	Oil Prices.....	98
18	6.	Spot Market Prices.....	98
19	7.	Capacity Contract Prices and Energy.....	99
20	8.	Planned and Forced Outages.....	99
21	9.	Normalization of Hourly Net System Load.....	100
22	10.	Losses.....	102
23	B.	Payroll, Payroll Related Benefits including 401k Benefit Costs.....	102
24	1.	Payroll Costs.....	102
25	2.	Payroll Related Benefits.....	105
26	3.	Payroll Taxes.....	105
27	4.	True-up of Payroll Costs.....	106
28	5.	FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset.....	106
29	6.	FAS 106 – Other Postretirement Benefit Costs (OPEBs) and OPEB Tracker	
30		Regulatory Liability.....	109
31	7.	Supplemental Executive Retirement Plan (SERP) Expense.....	113
32	8.	Talent Assessment Amortization.....	113
33	9.	March 2010 Organizational Realignment/Voluntary Separation (ORVS)	
34		Program.....	114
35	10.	Correction of Accounting for KCPL’s Iatan 2 Construction bonus payments.....	116
36	11.	Short Term Annual Incentive Compensation.....	117
37	12.	Long-Term Incentive Compensation.....	120
38	C.	Maintenance Normalization Adjustments.....	121
39	1.	Wolf Creek Nuclear Refueling Outage.....	123
40	2.	Nuclear Decommissioning.....	125
41	3.	Iatan 2 O&M Expenses.....	126
42	D.	Other Non-Labor Adjustments.....	127
43	1.	Hawthorn 5 SCR.....	127
44	2.	Hawthorn 5 Transformer.....	134
45	3.	Bad Debt Expense.....	135
46	4.	Advertising Expense.....	136

1	5.	Dues and Donations	137
2	6.	Miscellaneous Test Year Adjustments.....	138
3	a.	KCPL Adjustment CS-11	138
4	7.	Deloitte & Touche Expenses.....	139
5	8.	Expenses Concerning the Advanced Coal Tax Credit	140
6	9.	Legal Fee Reimbursements	142
7	10.	Debit/Credit Card Acceptance Program.....	142
8	11.	Accounts Receivable Bank Fees	143
9	12.	Lease Expense.....	144
10	13.	Insurance Expense.....	145
11	14.	Injuries and Damages.....	146
12	15.	Property Tax Expense	147
13	16.	Rate Case Expense	148
14	17.	Arbitration Expenses Concerning The Empire District Electric Company	167
15	18.	Public Service Commission Assessment Fee / FERC Assessment Fee.....	170
16	19.	Customer Deposits – Interest Expense.....	170
17	20.	Depreciation - Clearing	171
18	21.	Economic Relief Pilot Program	171
19	22.	Low-Income Weatherization Program.....	173
20	23.	SPP Administrative (Schedule 1-A) Fees	176
21	24.	Account 565 Transmission Expense	177
22	X.	Depreciation	178
23	A.	Recommendations.....	178
24	B.	Amortization Method:.....	179
25	C.	Reserve Transfers and Reinstatement of Reserves	180
26	D.	Assignment of the contributing sources (causes) of the under recovered amounts	182
27	E.	Regulatory Depreciation	185
28	XI.	Regulatory Plan Additional Amortizations	186
29	XII.	Current and Deferred Income Tax	190
30	A.	Income Tax Expense.....	190
31	B.	Kansas City Earnings Tax.....	191
32	C.	Accumulated Deferred Income Taxes	193
33	XIII.	Qualifying Advanced Coal Project Credit for Iatan Unit 2 Facility.....	195
34	A.	Iatan 2 Qualifying Advanced Coal Project Credit	195
35	1.	Iatan 2 Costs and Iatan 2 Benefits.....	209
36	2.	Kansas City Power & Light Company’s Obligations to KCP&L Greater Missouri Operations Company	210
37	3.	Iatan 2 Coal Credits Are an Acquisition Detriment	213
38			
39	XIV.	Jurisdictional Allocations.....	214
40	A.	Methodology	215
41	1.	Demand Allocation Factor	215
42	B.	Energy Allocation Factor	216

1	C. Application.....	217
2	XV. Other Miscellaneous Items.....	220
3	A. Demand-Side Management Cost Recovery	220
4	1. Missouri Energy Efficiency Investment Act of 2009 (“MEEIA”).....	222
5	2. Demand-Side Resources in Adopted Preferred Resource Plan.....	224
6	B. Demand-Side Management Program Prudence	225
7	1. Historical DSM Program Cost	225
8	2. Rate-Making Treatment for the DSM Program Cost.....	226
9	C. High Efficiency Street and Area Lighting	227
10	1. Current Street Lighting for KCPL Missouri	227
11	2. KCPL’s LED SAL Pilot Projects.....	228
12	D. Tariff Issues	229
13	E. KCPL Smart Grid Update.....	231
14	F. Renewable Energy Standard	236
15	1. Background Information	236
16	2. Renewable Energy Costs.....	237
17	G. Energy Independence and Security Act of 2007 (EISA).....	238
18	XVI. Transition Cost Recovery Mechanism	245
19	A. Acquisition Transition Cost Recovery.....	245
20	B. Qualifying Advanced Coal Project Credit for Iatan 2 Facility	254
21	C. Recommendations.....	255
22	D. Amortization Period Relating to the Transition Costs.....	256
23	XVII. Appendices	257
24		

1 Approximate customer counts for KCPL (Kansas and Missouri) from 2006 through
2 2011 follow:

Year	Total	Residential	Commercial	Industrial, Municipal and other Electric Utilities
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

3 source: KCPL and Great Plains' 2011, 2010, 2009, 2008, 2007 and 2006 Annual Reports at page 9

4 To serve its current customers KCPL owns total generating capacity of 4,500
5 megawatts-- 547 megawatts (MW) of nuclear capacity, 2,760 megawatts of coal capacity,
6 148 megawatts of wind capacity accredited at 12 megawatts, 771 megawatts of natural gas-fired
7 combustion turbine capacity, 410 megawatts of oil fired combustion turbine capacity, and it has
8 purchased power [source: Great Plains' 2011 Annual Report at page 23].

9 Attachment 1, at the end of this Report, is a map of the KCPL and GMO service territory.

10 This case, Case No. ER-2012-0174 (herein referred to the "2012 rate case"), is KCPL's
11 first general electric rate case after the end of KCPL's Experimental Alternative Regulatory Plan
12 (the "Regulatory Plan"), the Commission approved on July 28, 2005, in Case No.
13 EO-2005-0329.

14 During the Regulatory Plan, as contemplated in the plan, KCPL filed four general rate
15 increase cases to address the economic impacts on KCPL of its major environmental upgrades to
16 its LaCyne 1 and Iatan 1 generating units and the construction of Iatan 2—its new baseload,
17 850 megawatt coal-fired, generating unit. KCPL invested in 100 megawatts of wind-generated
18 capacity in September 2006 with phase one of its Spearville Wind Farm and to explore the
19 addition of a second 100 megawatts of wind-generated capacity, adding 48 megawatts
20 (accredited 4 megawatts) of wind capacity—Spearville 2 Wind Energy Facility—in 2010.
21 KCPL filed the four general rate increases on February 1, 2006 (Case No. ER-2006-0314 herein
22 referred to as the "2006 rate case"), February 1, 2007 (Case No. ER-2007-0291, herein referred

1 to as the "2007 rate case"), September 8, 2008 (Case No. ER-2009-0089, herein referred to as the
2 "2009 rate case") and June 4, 2010 (Case No. ER-2010-0355, herein referred to as the "2010 rate
3 case"), respectively. In the 2010 rate case the Commission found that as of August 26, 2010,
4 Iatan 2 was fully operational and used for service.

5 On April 4, 2007, Great Plains, KCPL, and Aquila, Inc. ("Aquila"), filed a joint
6 application with the Commission, designated as Case No. EM-2007-0374 requesting approval
7 for a series of transactions which ultimately would result in Great Plains acquiring Aquila's
8 Missouri electric and steam operations, as well as its merchant services operations. These
9 merchant services operations primarily consisted of a 340 megawatt generating facility located in
10 Mississippi, ("Crossroads"), and certain residual natural gas contracts. The Commission
11 approved the request of Great Plains, KCPL, and Aquila in an Order effective July 1, 2008.
12 Great Plains acquired Aquila on July 14, 2008 and later in 2008, Aquila changed its name to
13 KCP&L Greater Missouri Operations Company.

14 *Staff Expert/Witness: Cary G. Featherstone*

15 **II. Executive Summary**

16 In response to KCPL's February 27, 2012, application to increase its retail rates to
17 recover an additional approximately \$105.7 million per year Staff has conducted a review of all
18 the revenue requirement cost of service components (capital structure and return on investment;
19 rate base investment and income statement results, including revenues; operating and
20 maintenance expenses; depreciation expense; and related taxes, including income taxes) which
21 comprise KCPL's revenue requirement. The results of that review are presented in this Report,
22 including the Schedules and Accounting Schedules. The members of Staff who participated in
23 that review are identified in the sections of the report where their results are presented in verified
24 narrative format. The contemporaneously filed separate testimony, in question and answer
25 format, of Daniel I. Beck, of the Commission's Utility Operations Department, and Cary G.
26 Featherstone of the Utilities Services Department state Staff's recommended revenue
27 requirement, which results from the analysis and recommendations described in this Report.

28 Staff recommends a return on equity ("ROE") range of 8.00% to 9.00%, with a mid-point
29 of 8.5%, which yields the rate of return range of 7.14% to 7.66%. Staff's KCPL revenue
30 requirement calculation, which is based on KCPL actual costs through March 31, 2012, indicates

1 a shortfall of between \$16.5 million to \$33.7 million based on current KPCL rates, which
2 generate approximately \$693.8 million. With the increase of between \$16.5 to \$33.7 million
3 (2.4% to 4.8%), the Staff's total KCPL revenue requirement recommendation is approximately
4 \$710.3 to \$727.5 million. Because of changes expected for the true-up items through August 31,
5 2012, that are not known and measurable at this time, the Staff's revenue requirement for KCPL
6 will change when the true-up is completed in this case.

7 Staff anticipates there will be plant additions through the August 31, 2012, true-up cut-off
8 in this case, as well as cost increases in payroll and, payroll related benefits such as pensions and
9 medical costs. Fuel prices will also be examined for any changes as part of the true-up process.
10 Staff also examined the Additional Amortizations from the Regulatory Plan, and their treatment
11 in this rate case based on the agreement reached in KCPL's last case, Case No. ER-2010-0355.

12 The following is a non-exhaustive list of areas in this report:

- 13 • Rate of Return
- 14 • Removal of the Additional Amortizations from the test year
- 15 • KCPL's costs for new wind generation as a purchased power
16 agreement expected to be completed by the end of the true-up
17 August 31, 2012
- 18 • Remaining costs for the additional plant for KCPL investment
19 in the Iatan 2 not captured in its last rate case
- 20 • KCPL's investment in Iatan Common Plant not captured in its
21 last rate case
- 22 • KCPL's fuel costs, including freight rate changes and purchased
23 power costs
- 24 • KCPL's off-system sales margins from the firm and non-firm
25 bulk power markets
- 26 • KCPL's pension and other post-employment benefits (OPEBS)
27 costs
- 28 • Jurisdictional Allocations
- 29 • Acquisition savings and transition costs

30 *Staff Expert/Witness: Cary G. Featherstone*

1 **III. Kansas City Power and Light Company's Rate Case Filing**

2 KCPL filed its general rate increase case on February 27, 2012, reflecting an annual
3 increase in Missouri retail rate revenues of \$105.7 million. KCPL requested a 15.1% increase.
4 The Commission designated this rate case as Case No. ER-2012-0174. KCPL requested a rate of
5 return on equity of 10.4% applied to a 52.5% equity capital structure for Great Plains
6 [paragraphs 6 and 7 KCPL's Application- Minimum Filing Requirements page 3].

7 GMO also filed a rate case on February 27, 2012, for its electric operations. This case
8 has been designated as Case No. ER-2012-0175. GMO has different rates in two different
9 geographical areas – one in and about Kansas City, which was formerly served under the d/b/a
10 Aquila Networks - MPS and one about St. Joseph, Missouri, which was formerly served under
11 the d/b/a Aquila Networks – L&P. For ease, the areas with differing rates are referenced as
12 “MPS” and “L&P” in this report. For MPS, GMO requested a rate increase of \$58.3 million per
13 year, representing a 10.9% increase. For L&P electric service, GMO requested a rate increase of
14 \$58.3 million per year, representing a 10.9% increase. These GMO requests are based on a
15 proposed rate of return on equity of 10.4% applied to the 52.5% equity capital structure for Great
16 Plains [source: paragraphs 6 and 7 of GMO Application- Minimum Filing Requirements page 3 and GMO
17 Press Release].

18 *Staff Expert/Witness: Cary G. Featherstone*

19 **A. Test Year**

20 As the Commission ordered April 19, 2012, the test year in this case, as well as the GMO
21 case for MPS and L&P, is the 12-month period ending September 30, 2011, updated for known
22 and measurable changes through March 31, 2012, and true-up through August 31, 2012. Staff's
23 revenue requirement as presented in its Accounting Schedules includes preliminary estimates for
24 expected changes as of the true-up cut-off date of August 31, 2012, based on current information.

25 *Staff Expert/Witness: Cary G. Featherstone*

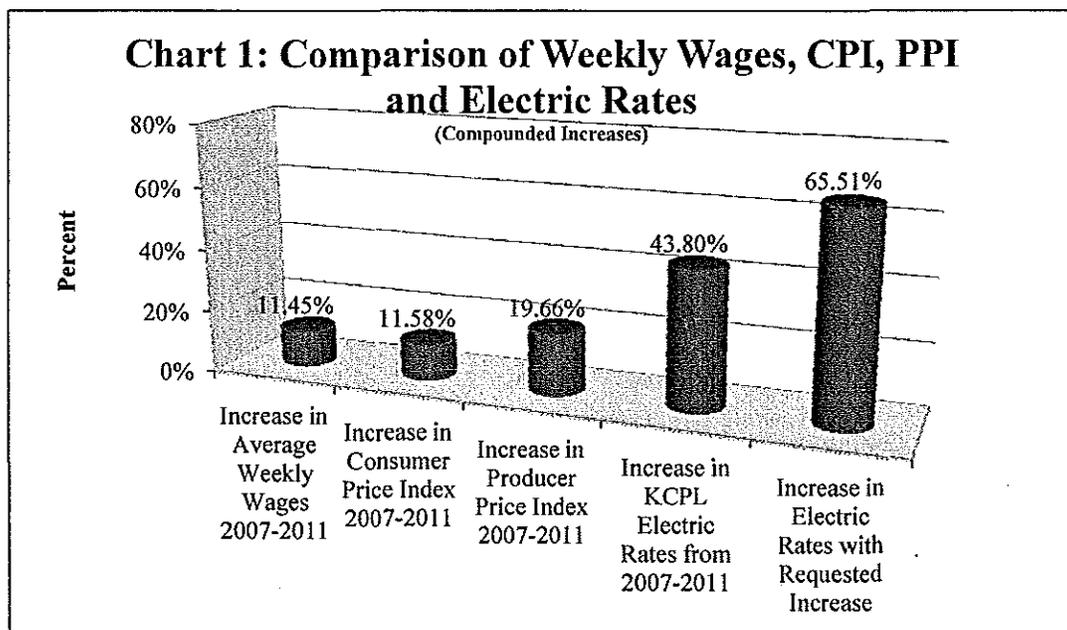
26 **B. True-up Case**

27 Because of anticipated cost increases, including plant additions and a new purchased
28 power agreement for 100 megawatts of wind turbine power anticipated by the summer of 2012, at
29 KCPL's request the Commission established a true-up through the August 31, 2012.

30 *Staff Expert/Witness: Cary G. Featherstone*

1 **IV. Economic Considerations**

2 As demonstrated below, Missouri, and specifically the counties² in the Missouri service
3 area of KCPL have experienced challenging economic times since 2007 due to the recession and
4 a slow recovery. Additionally, KCPL consumers in Missouri have experienced a 43.80%
5 increase in electric rates since 2007, while experiencing an increase in average weekly wages of
6 less than one-third of that amount. Chart 1 provides a comparison of the increase in average
7 weekly wages for the Missouri counties in the KCPL service area, Consumer Price Index
8 (“CPI”), Producer Price Index (“PPI”)³ and KCPL electric rates in Missouri.



9
10 From 2007 to 2011⁴ the counties in the Missouri KCPL service area collectively
11 experienced an 11.45% increase in average weekly wages. This was slightly lower than the
12 overall Missouri compounded increase in average weekly wages of 11.63%. During that same

2 According to the minimum fling requirements KCPL submitted to the Missouri Public Service Commission, KCPL serves 13 counties in Missouri; Cass, Clay, Jackson, Johnson, Platte, Lafayette, Livingston, Pettis, Saline, Howard, Randolph, Chariton and Carroll. The boundaries of the KCPL service territory do not follow specific county boundaries. This report does not include counties in the GMO service area.

3 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.

4 Average weekly wage data for 2011 is still preliminary.

1 time period the CPI increased 11.58% and electric rates for Missouri KCPL customers increased
2 43.80%, shown in Table 1.

Case Number	Effective Date	Dollar Value	Percent Increase
ER-2006-0314	January 1, 2007	\$50,616,638	10.46%
ER-2007-0291	January 1, 2008	\$35,308,914	6.50%
ER-2009-0089	September 1, 2009	\$95,000,000	16.16%
ER-2010-0355	May 4, 2011	\$34,817,199	5.23%
Total Dollars		\$215,742,751	
Total Compounded Increase			43.80%

3
4 The total increase in KCPL's revenues from these cases was approximately \$216 million.
5 For this same time period of 2007 to 2011, purchasers of industrial commodities, such as KCPL,
6 have, on the average, also experienced inflationary pressure, illustrated by a 19.66% increase in
7 the PPI for Industrial Commodities.⁵

8 Based on a update period ended March, 2012, tried up through August 31, 2012, KCPL
9 is currently requesting an increase of \$105.7 million in its revenue requirement, which is a 15.1%
10 increase over the current rates approved in Case No. ER-2010-0355. If the increase requested by
11 KCPL is approved, the total increase since January 1, 2007 would be 65.51%.

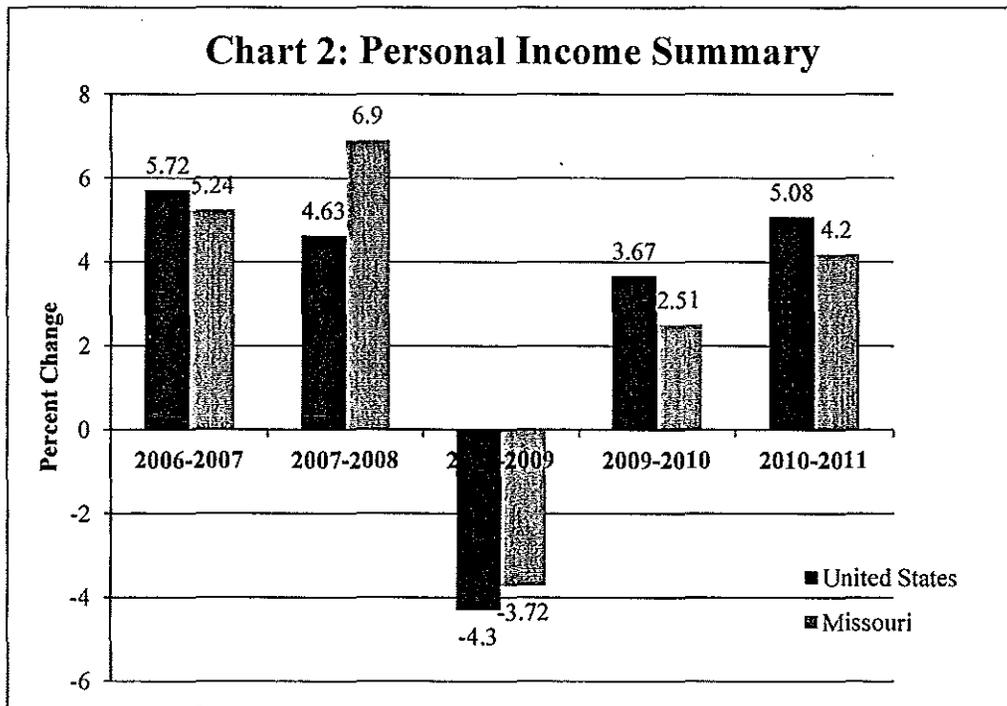
12 The increase in average weekly wages for counties in the Missouri KCPL service area is
13 about one-fourth of the increase in Missouri electric rates for KCPL from 2007 to 2011 and less
14 than one-fifth of the increase in rates if KCPL receives the 15.1% it is requesting in this case. In
15 addition, in the first quarter of 2012 the cost of living utility index⁶ for Missouri was 103.1. This
16 indicates that general utility expenses constitute a higher percentage of a Missouri resident's
17 living expenses than the average U.S. resident. The U.S. average is an average of the

5 Detailed information on KCPL's expenditures and revenues can be found later in the Staff's Cost-of-Service Report.

6 Source: Missouri Economic Research and Information Center ("MERIC") and The Council for Community & Economic Research - 1st Quarter 2012. The cost of living composite index represents indices for grocery items, housing, utilities, transportation, health care and misc. services. The utility index includes electric, natural gas and telephone services.

1 participating urban areas in that quarter and is the “base” value which serves as the comparison
2 at 100. Although average weekly wages are increasing, the cost of living reflected by the CPI is
3 increasing, decreasing the positive impact of the increase in average weekly wages.

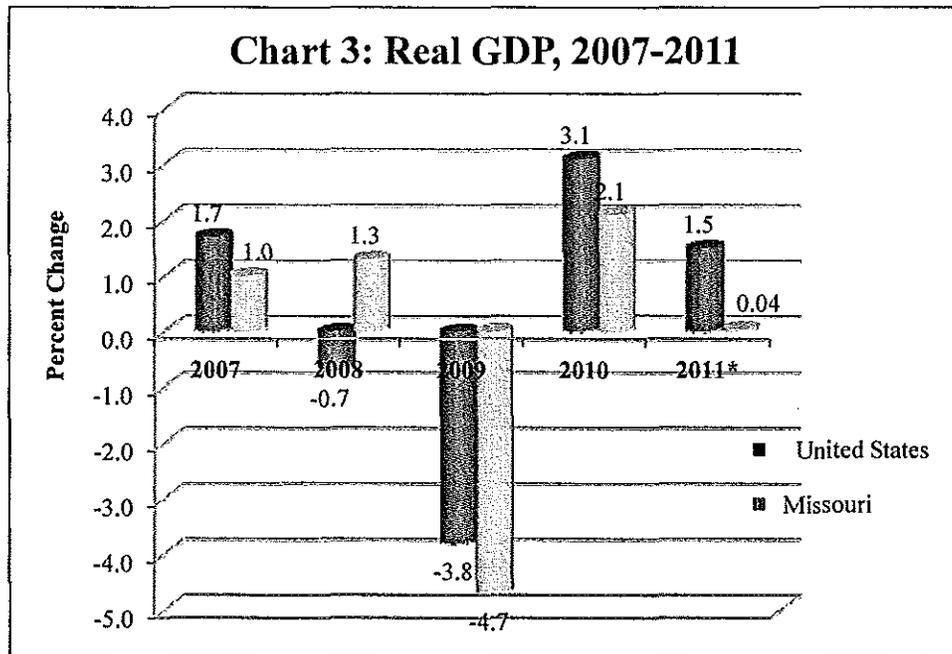
4 According to the Current Economic Conditions in the Eighth Federal Reserve District
5 report from the Federal Reserve Bank of St. Louis,⁷ Missouri’s recovery has been slower
6 compared to the nation in personal income and economic activity. Chart 2, illustrates this
7 through a comparison of personal income between the United States as a whole and Missouri,
8 based on data obtained from the Bureau of Economic Analysis.



9
10 This data shows that Missouri experienced a percentage change between 2010 and 2011
11 of positive 4.2% in personal income, while the nation experienced a percentage change of
12 positive 5.08%.

⁷ The Federal Reserve Bank of St. Louis’ Current Economic Conditions in the Eighth Federal Reserve District, June, 2012 report included state and national level data as well as MSA level data for the St. Louis area. The only information used from the report was the national and state comparisons.

1 The Federal Reserve Bank of St. Louis, using data from the Federal Reserve Bank of
 2 Philadelphia, also reported that Missouri's coincident index,⁸ as of June 2012, is at 94.4% of its
 3 pre-recession level where the nation is at 101.2% of its pre-recession level. Missouri's lowest
 4 level of economic activity was reported at 91.9% of pre-recession levels while the U.S only
 5 dropped to 95.3% of its pre-recession level. Missouri also falls behind the nation in Gross
 6 Domestic Product ("GDP") growth in 2010 and 2011, illustrated in Chart 3.



7
 8 Chart 3, shows that Missouri's real GDP^{9 & 10} only increased 0.04% in 2011, while that of
 9 the nation grew 1.5%. In 2010, Missouri's real GDP grew less than the nation's real GDP of
 10 2.1% and 3.1%, respectfully. Growth in real GDP occurred in 2010 after Missouri's real GDP
 11 declined by 4.7% in 2009, compared to the nation's real GDP decline of 3.8%.

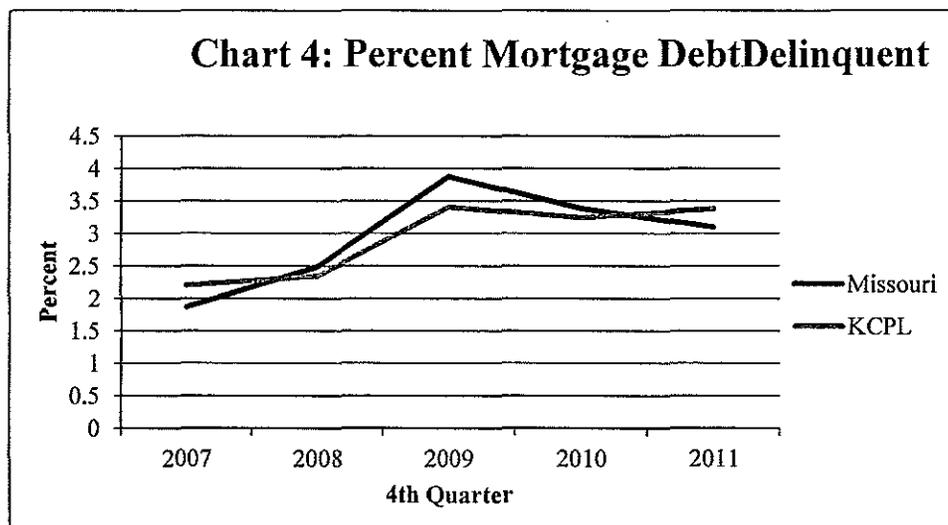
8 The Federal Reserve Bank of Philadelphia's coincident index is a combination of payroll employment, wages, unemployment and hours of work to give a single measure of economic performance. Per the Federal Reserve Bank of St. Louis, June 2012, "The Federal Reserve Bank of Philadelphia has significantly revised their national coincident economic activity index since our previous publication."

9 Source: Bureau of Economic Analysis ("BEA") – Real GDP, All Industries.

10 Advance 2011 real GDP by State statistics and revised 1997 - 2010 statistics were released on June 5th, 2012 by the Bureau of Economic Analysis. Real GDP by Metropolitan Statistical Area ("MSA") for 2011 have not yet been released.

1 Real GDP¹¹ for the Kansas City MO-KS Metropolitan Statistical Area (“MSA”), which
2 includes six counties in Kansas and nine counties in Missouri,¹² grew by 1.5% in 2010, which is
3 also behind the U.S. Metropolitan portion’s real GDP growth of 2.5%. The personal income
4 data, the coincident index data and the real GDP data suggests that Missouri is experiencing a
5 slower recovery than the nation.

6 As explained below, the residents and businesses in the Missouri counties in the KCPL
7 service area are recovering from the longest and worst recession since the Great Depression¹³ on
8 lower than the national average weekly wage, lower than the national average per capita personal
9 income and the unemployment rate peaked at 9.8%¹⁴ in 2010. However, the state average for
10 mortgage debt delinquency peaked in 2009 above the average for the Missouri KCPL service
11 area, as shown in Chart 4.



12 Nevertheless, percent mortgage delinquency has increased greatly between the fourth
13 quarter of 2007 and the fourth quarter of 2011 for both the state in general and the Missouri
14 KCPL service area. The values in Chart 4 can be interpreted as percent of mortgage debt balance
15

11 The BEA defines GDP by state as, “the value added in production by the labor and capital located in a state,” where GDP by metropolitan area is, “the measure of the market value of all final goods and services produced within a metropolitan area in a particular period of time (annually).”

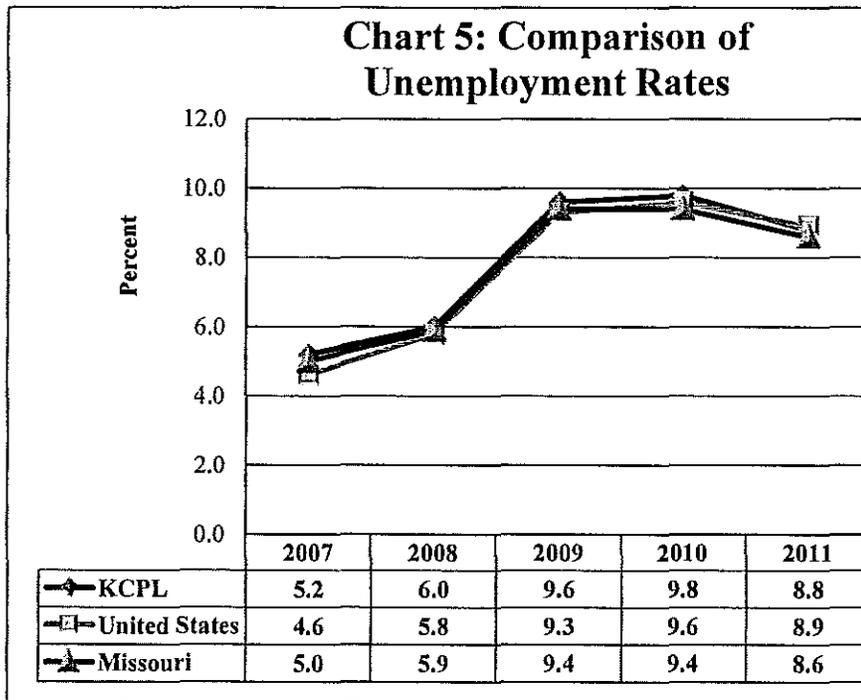
12 Five (Cass, Clay, Platte, Jackson and Lafayette) of the nine Missouri counties in the Kansas City, MO-KS MSA are in the Missouri KCPL service area.

13 The Economic Report of the President, Chapter 1, Federal Reserve Bank of St. Louis

14 The Missouri KCPL service area unemployment rate is calculated as a percentage of the total labor force.

1 that is 90+ days delinquent.¹⁵ Of the Missouri counties¹⁶ in the KCPL service area, Randolph
 2 County had the highest percent of mortgage debt balance 90+ days delinquent in 2011 at 4.98%,
 3 up from 1.21% in 2007, Jackson County followed at 4.24% in 2011 up from 2.45% in 2007.
 4 Johnson County reported the lowest mortgage debt delinquent at 1.81%, just slightly up from
 5 2007 at 1.71%.

6 Missouri counties served by KCPL experienced a slightly higher unemployment rate¹⁷
 7 than Missouri and the U.S. in 2007, 2008, 2009 and 2010, but fell slightly below the U.S.
 8 unemployment rate in 2011, while staying higher than the Missouri unemployment rate, as
 9 demonstrated in Chart 5, below.



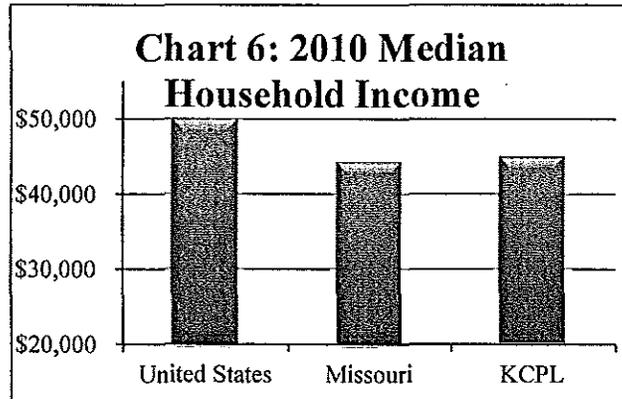
10
 11 Although the unemployment rate in Missouri counties that KCPL serves seems to be
 12 decreasing in 2011, all of the Missouri counties in the KCPL service area had higher
 13 unemployment rates in 2011 than in pre-recession 2007.

15 Source: Federal Reserve Bank of New York, Consumer Credit Panel, 90+ days delinquent is considered seriously delinquent and in the foreclosure process.

16 The Federal Reserve Bank of New York – Consumer Credit Panel, “only includes counties with an estimated population of at least 10,000 consumers with credit reports in the 4th quarter 2011.” This includes 77 of the 115 counties in Missouri and 10 of the 13 counties in the Missouri KCPL service area.

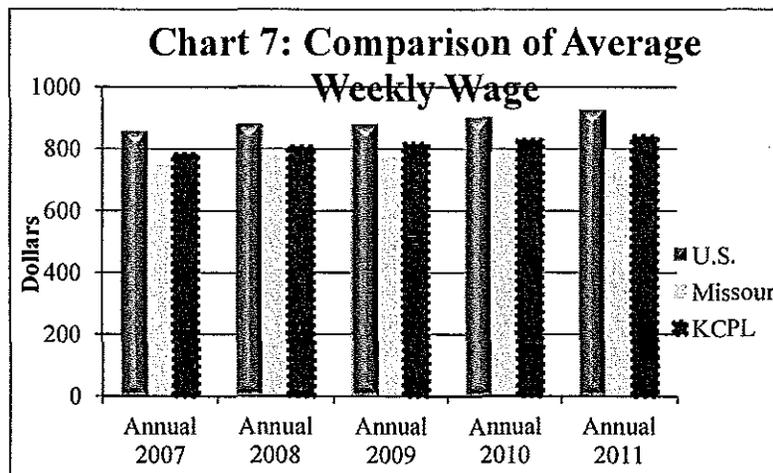
17 Source: Bureau of Labor Statistics, Local Area Unemployment Statistics.

1 Chart 6, illustrates median Missouri household income based on data from the Missouri
2 Economic Research and Information Center ("MERIC").



3
4 On average, households in the Missouri KCPL service area fell below the national
5 median household income level in 2010, but were slightly higher than the Missouri median
6 household income level in 2010.

7 Average weekly wages¹⁸ for workers in the Missouri KCPL service area also fell below
8 the national average, but are slightly higher than the state average, as shown in Chart 7.

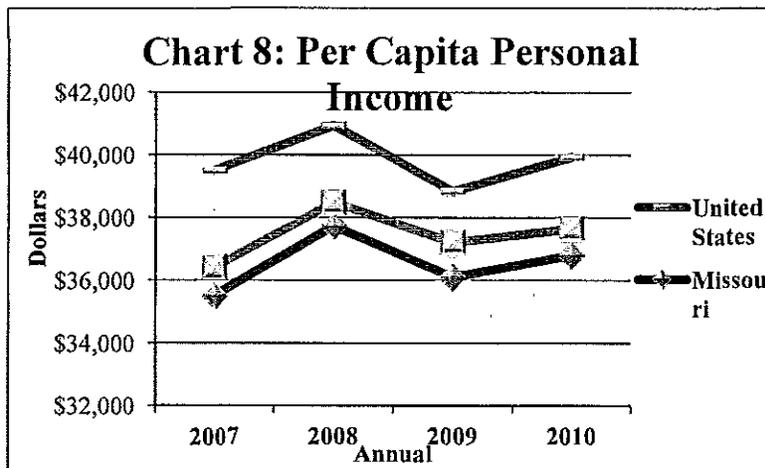


9
10 All of the average weekly wages in the Missouri counties in KCPL's service area were
11 lower than the national average of \$924. The only two Missouri counties in KCPL's service area
12 that reported a higher average weekly wage than the state average of \$797 were Jackson County
13 at \$918 and Clay County at \$849. The median average weekly wage in 2011, based on data from

18 Source: Bureau of Labor Statistics: Quarterly Census of Employment and Wages, Average Weekly Wage 2007 - 2011. Per Bureau of Labor Statistics, "annual average weekly wage values are calculated by dividing total annual wages by the average of the twelve monthly employment levels and dividing the result by fifty-two."

1 all 13 Missouri counties in KCPL's service area, is \$588. This can be interpreted as the average
2 weekly wage in 50% of these counties is below \$588 and 50% are above.

3 In 2010,¹⁹ the per capita personal income²⁰ level for the KCPL service area in Missouri,
4 as a whole, was \$37,651, which was slightly higher than the state average of \$36,799, but lower
5 than the national per capita personal income level of \$39,937. Chart 8 shows a comparison of
6 per capita personal income between the Missouri counties served by KCPL, Missouri and the
7 U.S.



8
9 Platte County reported a per capita personal income level of \$43,303 for its residents in
10 2010, which is the only Missouri County in KCPL's service area that reported a higher per capita
11 personal income level than the national level of \$39,937. However, Platte County's per capita
12 income of 2010 is below the per capita personal income level of \$45,027 it reported in 2008. In
13 2011, Missouri reported a per capita personal income of \$38,248 which fell below the national
14 per capita personal income level of \$41,663. However, this was the first time both the state and
15 the nation experienced a per capita personal income level that surpassed the 2008 levels by
16 approximately 1.5%.

17 Collectively, the Missouri counties in KCPL's service area have higher average
18 weekly wage and per capita personal incomes than the Missouri average, but the Kansas City,

19 Source: Bureau of Economic Analysis, Local Area Personal Income data for 2011 will not be available until November 26th, 2012.

20 Per capita personal income is calculated as total personal income divided by total midyear population.

1 MO-KS MSA has a higher cost of living composite index²¹ & ²² at 98.7 compared to Missouri's
2 at 92.7. In fact, the Kansas City, MO-KS MSA had the highest cost of living composite index
3 compared to all other MSA's in Missouri during the first quarter of 2012. Again, the index
4 values can be interpreted as a percentage of the U.S. average²³ which serves as the "base" value
5 and the comparison at 100.

6 KCPL Missouri's average cents per kWh as reported by the Edison Electric Institute
7 ("EEI") for total retail is 8.01²⁴ for the twelve months ending December 31, 2011 is lower than
8 the national average as calculated by EEI of 10.09 cents per kWh. However, as a whole,
9 Missouri counties in KCPL's service area have per capita personal income and average weekly
10 wages below the national average, and unemployment rates in 2011 that were higher than its
11 2007 pre-recession unemployment rates.

12 It is important to note that average cents per kWh reported by EEI is not a specific
13 tariffed rate paid by consumers. EEI does not describe how it calculates the average cost per
14 kWh that it reports. Average cents per kWh can be calculated as total revenues collected by the
15 utility divided by total kWh, which can include revenues from energy efficiency program
16 charges, customer charges, demand charges, fuel adjustment charges or any other type of
17 specialty program in addition to a customer's general energy rate. Each utility has different
18 billing and rate structures. On a national level a utilities' average cents per kWh is compared
19 using three rate groups (residential, commercial and industrial) and by a composite category
20 called total retail. KCPL has twenty-one rate groups and none of them are specifically called
21 "commercial" or "industrial."

22 Staff compared an average monthly bill for a typical Missouri KCPL residential customer
23 to other investor-owned utilities operating in Missouri based current tariff rates and on the
24 average monthly winter and summer usage reported in its minimum filing requirements, shown
25 in Table 2.

21 Source: Missouri Economic Research and Information Center ("MERIC") and The Council for Community & Economic Research – 1st Quarter 2012.

22 The composite index represents indices for grocery items, housing, utilities, transportation, health care and misc. services.

23 The U.S. average is an average of the participating urban areas in that quarter.

24 Source: EEI Typical Bill Rankings Report and Typical Bill/Average Rates Report, provided by KCPL in Data Request 241.1 in Case No. ER-2012-0174. Average cents per kWh for total retail includes the subgroups of residential, commercial and industrial.

Table 2: Comparison of Residential Customers

760 kWh - Winter Usage, 1150 - Summer Usage

	GMO- MPS	GMO- L&P	KCPL	Ameren Missouri	Empire
Date of Current Rate	6/25/2011	6/25/2014	5/4/2011	7/31/2011	6/15/2011
Average Monthly Bill	\$104.47	\$98.55	\$97.27	\$87.08	\$106.29

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

According to the EEI report GMO-L&P reports the lowest average cents per kWh for a residential customer at 8.64¢, compared to all other Missouri investor-owned utilities. However, a typical GMO-L&P residential customer's average monthly bill is higher than an Ameren Missouri residential customer's bill and slightly higher than a Missouri KCPL residential customer's bill, using the same amount of usage. From the EEI report, Ameren Missouri's average cents per kWh is 8.80¢ and KCPL's average cents per kWh for a Missouri residential customer is 9.90¢. If the 9.90¢ was applied to the average usage, rather than KCPL's actual tariffed residential rates the average monthly bill should be approximately \$88 rather than \$97.

Again, average cents per kWh reported by EEI are not tariffed specific rates. Many utilities have different blocked rates based on usage, such as the first 650 kWh or the first 1000 kWh and different rates for summer and winter; therefore it is difficult to get an average energy rate per kWh.

Staff Expert/Witness: Robin Kliethermes

continued on next page

1 **V. Kansas City Power & Light Company Electric Rates**

2 KCPL has filed for the following rate increases under the Regulatory Plan:

3

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	Pending	January 2013 expected

4
5 KCPL had not had a general rate increase case prior to the 2006 rate case since the
6 Wolf Creek Operating Corporation ("Wolf Creek" or WCNOC) rate case filed as Case No.
7 EO-85-185. Since the 1985 Wolf Creek rate case, and the phase-in of rates relating to this
8 nuclear generating unit, there have been several rate reductions as result of Staff earnings
9 reviews. The following table identifies the rate activity for KCPL:

10

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)

1 Staff did a comparison of KCPL's electric rates in Missouri with other electric utilities in
 2 Missouri and Kansas. Based on information supplied to by KCPL to the Edison Electric Institute
 3 that KCPL in turn provided in response to a Staff data request, the rates KCPL charges its
 4 Missouri residential customers are below the national average and generally below those of other
 5 Missouri and mid-western utilities.

6 The following table shows such a comparison of KCPL's actual composite residential
 7 customer rates as of January 1, 2012:

Missouri and Kansas Residential-in cents per kilowatt hour	2011	2010	2009	2008	2007	2006	2005
MISSOURI RATES							
KCPL-Missouri	9.90 cents/kwh	9.53	8.51	8.14	7.61	6.90	6.88
MPS	10.81	10.52	9.67	9.10	8.64	8.08	7.45
L&P	8.64 Does not include Phase 2 rates in effect June 2012	7.97	7.43	7.03	6.78	6.31	5.97
Ameren Missouri	8.80	7.82	7.03	6.53	6.60	6.60	6.52
Empire- Missouri	11.22	9.95	9.75	9.19	9.10	8.35	7.98
Missouri Average	9.39	8.54	7.77	7.27	7.18	6.96	6.77
KANSAS RATES							
KCPL- Kansas	10.58	9.67	9.07	8.43	7.43	6.92	6.88
Empire - Kansas	10.53	9.65	8.97	9.26	9.20	8.69	7.11
Westar Energy -- KGE	9.92	9.46	8.84	7.84	7.29	7.72	7.74
Westar Energy -- KPL	9.93	9.55	9.17	8.07	7.16	7.36	6.69
Kansas Average	10.12	9.56	9.03	8.12	7.31	7.51	7.27
United States Average	12.07	12.01	11.72	11.53	10.95	10.62	9.60

Source: EEI Winter 2010 Report, page 180 provided Data Request 380- ER-2010-0355
 EEI Winter 2012 Report, page 212 provided Data Request 241- ER-2012-0174

9
10
11

1 As shown in the table below, KCPL's commercial rates are now, and for several years
 2 have been higher than those for L&P customers, but lower than MPS customers while KCPL's
 3 residential rates are above the Missouri average but below the United States national average:
 4

Missouri and Kansas Commercial-in cents per kilowatt hour	2011	2010	2009	2008	2007	2006	2005
MISSOURI RATES							
KCPL-Missouri	7.62 cents/kwh	7.31	6.56	6.22	5.92	5.49	5.48
MPS	8.45	8.25	7.62	7.08	6.59	6.16	5.94
L&P	7.36 Does not include Phase 2 rates in effect June 2012	6.69	6.26	5.86	5.51	5.26	5.37
Ameren Missouri	6.92	6.29	5.71	5.34	5.34	5.32	5.29
Empire- Missouri	9.94	8.82	8.60	8.13	7.96	7.32	7.08
Missouri Average	7.40	6.85	6.26	5.87	5.74	5.56	5.50
KANSAS RATES							
KCPL- Kansas	8.38	7.57	7.20	6.62	6.13	5.90	5.87
Empire - Kansas	11.21	10.27	9.48	9.62	9.61	9.19	7.64
Westar Energy -- KGE	7.97	7.57	7.31	6.66	6.03	6.38	6.29
Westar Energy -- KPL	7.99	7.64	7.33	6.54	5.68	5.89	5.22
Kansas Average	8.12	7.61	7.30	6.61	5.93	6.24	5.96
United States Average	10.20	10.21	10.03	10.05	9.53	9.33	8.67

5 Source: EEI Winter 2010 Report, page 246 provided Data Request 380- ER-2010-0355
 6 EEI Winter 2012 Report, page 244 provided Data Request 241- ER-2012-0174
 7

8 The table below shows KCPL's industrial rates are now and for several years have been
 9 higher than those for L&P customers, but lower than MPS customers while KCPL's residential

1 rates are above the Missouri average but below the United States national average as of
 2 January 1, 2012:

Missouri and Kansas Industrial-in cents per kilowatt hour	2011	2010	2009	2008	2007	2006	2005
MISSOURI RATES							
KCPL-Missouri	5.83 cents/kwh	5.57	5.13	4.77	4.47	4.21	4.23
MPS	6.28	6.26	5.82	5.34	4.89	4.58	4.49
L&P	5.61	5.16	4.96	4.60	4.26	3.98	3.97
Ameren Missouri	4.87	4.46	4.30	3.87	3.89	3.96	4.05
Empire- Missouri	7.72	6.89	6.60	6.19	6.08	5.51	5.41
Missouri Average	5.30	4.90	4.73	4.26	4.18	4.14	4.61
KANSAS RATES							
KCPL- Kansas	7.95	7.06	6.73	6.15	5.50	5.15	5.15
Empire - Kansas	8.26	7.42	7.01	6.97	6.94	6.32	5.02
Westar Energy -- KGE	5.89	5.47	5.34	4.78	4.17	4.36	4.32
Westar Energy -- KPL	6.84	6.50	6.31	5.62	4.83	5.01	4.40
Kansas Average	6.34	5.91	5.75	5.15	4.49	4.77	4.65
United States Average	6.64	6.71	6.63	6.66	6.15	6.00	5.73

4 Source: EEI Winter 2010 Report, page 278 provided Data Request 380- ER-2010-0355
 5 EEI Winter 2012 Report, page 276 provided Data Request 241- ER-2012-0174
 6

7 The above rates represent information supplied to Edison Electric Institute for
 8 publication entitled *EEI Typical Bills and Average Rate Report – Winter 2012*. Each utility who
 9 participates in the survey supplies information on its rates to EEI. The above rates relate to
 10 actual composite rates determined using actual revenue and kilowatt hour usage as of
 11 December 31 of a given year. As a cautionary note, these actual composite rates should not be
 12 confused with rates appearing in the tariff sheets of a utility. Also the commercial and industrial
 13 classes are used by federal filings such with the Securities Exchange Commission and FERC

1 annual reports these classes do not reflect the categories of customer classes found in the tariffs
2 of the Missouri companies.

3 While the information in these charts is most current available, these rates do not reflect
4 the full year of any rate increases granted in 2011 for KCPL and GMO as well as the other
5 utilities. As an example, the KCPL rates for Missouri do not reflect the full year of rate increase
6 for Missouri approved by the Commission in Case No. ER-2010-0355 in April 2011. Both MPS
7 and L&P rates appearing in the EEI rate book do not reflect the full year's annual rate impact of
8 the Commission approved rates in Case No. ER-2010-0356 in June 2011 nor does the rate for
9 L&P reflect the second Phase of the rate increase authorized for June 2012.

10 GMO filed more recent rate information for MPS and L&P in its rate application in Case
11 No. ER-2012-0175 concerning residential rates that reflect the impact of second phase in that
12 took effect June 2012. In its minimum filing requirements filed in File No. ER-2012-0175,
13 GMO identified its proposed rate increase for MPS would be 11.66 cents per kilowatt hour and
14 L&P 10.97 cents per kilowatt hour (assuming full requested rate award). The residential rates
15 for MPS and L&P have become closer since the last rate GMO case. In comparison, KCPL's
16 proposed residential rate in this case is 11.56 cents per kilowatt hour (assuming full requested
17 rate award). If the full rate requests are granted by the Commission, KCPL's residential rates
18 would still be between those for MPS and L&P.

19 *Staff Expert/Witness: Cary G. Featherstone*

20 **VI. Rate of Return**

21 **A. Introduction**

22 An essential ingredient of the cost-of-service ratemaking formula is the rate of
23 return ("ROR"), which is designed to provide a utility with a return of the costs required to
24 secure debt and equity financing. This ROR is equal to the utility's weighted average cost of
25 capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate
26 capital structure by its cost and then summing the results. While the proportion and cost of most
27 components of the capital structure are a matter of record, the cost of common equity must be
28 determined through expert analysis. Staff's expert financial analyst, David Murray, has
29 determined KCPL's cost of common equity by applying well-respected and widely-used
30 methodologies to data derived from a carefully-assembled group of comparable companies.

1 Staff then used that cost of common equity, net of any risk adjustments, together with
 2 other capital component information as of June 30, 2012, to calculate KCPL's fair rate of return,
 3 as follows:

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of:		
			8.00%	8.50%	9.00%
Common Stock Equity	**	—	—	—	**
Preferred Stock	**	—	—	—	**
Long-Term Debt	**	—	—	—	**
Total	<u>100.00%</u>		<u>7.14%</u>	<u>7.40%</u>	<u>7.66%</u>

5
 6 As contained in the above table, Staff estimates, based upon its expert analysis, a cost of
 7 common equity range of 8.00% to 9.00%, mid-point 8.50%, and an overall ROR of 7.14% to
 8 7.66%, mid-point 7.40%. Staff recommends that the Commission authorize a return on
 9 common equity of 9.00% based on the high-end of its estimated cost of equity due to
 10 past concerns about Staff's estimates being too low. However Staff considers anywhere within
 11 its range of 8.00% to 9.00% to be reasonable but for purposes of its revenue requirement Staff
 12 used 9.00%. The details of Staff's analysis and recommendations are presented in attached
 13 Appendix 2, Schedules 1-23. Staff's workpapers will be provided to the parties at the time of
 14 filing Staff's Cost of Service Report. Staff will make any source documents of specific interest
 15 available upon the request of any party to this case or upon the Commission's request.

16 **B. Analytical Parameters**

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

NP

1 of a Constitutionally-acceptable rate of return in two frequently-cited cases.²⁵ In *Bluefield Water*
2 *Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:²⁶

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

17 Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co.*, the
18 Court stated:²⁷

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

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

25 *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).

26 262 U.S. 679, 692-693, 43 S.Ct. 675, 679, 67 L.Ed. 1176.

27 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345.

- 1 1. A return consistent with returns on investments of comparable risk;
- 2 2. A return sufficient to assure confidence in the utility's financial
- 3 integrity; and
- 4 3. A return that allows the utility to attract capital.

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

9 The methodologies of financial analysis have advanced greatly since the *Bluefield* and
10 *Hope* decisions.²⁸ Additionally, today's utilities compete for capital in a global market rather
11 than a local market. Nonetheless, the parameters defined in those cases are readily met using
12 current methods and theory. The principle of the commensurate return is based on the concept of
13 risk. Financial theory holds that the return an investor may expect is reflective of the degree of
14 risk inherent in the investment, risk being a measure of the likelihood that an investment will not
15 perform as expected by that investor. Any line of business carries with it its own peculiar risks
16 and it follows, therefore, that the return KCPL's shareholders may expect is equal to that
17 required for comparable-risk utility companies.

18 Financial theory holds that the company-specific Discounted Cash Flow ("DCF") method
19 satisfies the constitutional principles inherent in estimating a return consistent with those of
20 companies of comparable risk;²⁹ however, Staff recognizes that there is also merit in analyzing a
21 comparable group of companies as this approach allows for consideration of industry-wide data.
22 Because Staff believes the cost of equity can be reliably estimated using a comparable group of
23 companies and the Commission has expressed a preference for this approach, Staff relies
24 primarily on its analysis of a comparable group of companies to estimate the cost of equity for
25 KCPL.

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

29 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*.

1 In this case, Staff has applied this comparable company approach through the use of both
2 the DCF method and the Capital Asset Pricing Model ("CAPM"). Properly used and applied in
3 appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate
4 estimates of a utility's cost of equity. Because it is well-accepted economic theory that a
5 company that earns its cost of capital will be able to attract capital and maintain its financial
6 integrity, Staff believes that authorizing an *allowed* return on common equity based on the
7 *cost* of common equity is consistent with the principles set forth in *Hope* and *Bluefield*.
8 However, as Staff will discuss extensively throughout this section of the report, Staff believes its
9 recommended return on equity is higher than KCPL's cost of equity.

10 C. Current Economic and Capital Market Conditions

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

16 1. Economic Conditions

17 The United States economy has been growing at a tepid pace since the most severe
18 recession since the Great Depression. The pattern of this slow economic recovery has been
19 much different than other past recoveries from severe recessions, in which the economy usually
20 grew at a fairly rapid pace for a few years following the recession. This has investors,
21 policy makers and academics concerned about the long-term prospects for not only U.S. growth,
22 but for that of global economic growth. Most economists project domestic economic growth to
23 be lower in the long-term as compared to the growth rates achieved during the post World War II
24 era before the recent recession. Economists generally expect the long-term nominal GDP growth
25 rate to be in the range of 4% to 5%.³⁰ These projected long-term nominal GDP growth rates
26 generally are predicated on 2% expected inflation, as measured by the GDP price deflator.

30 The Congressional Budget Office ("CBO"), *The Budget and Economic Outlook: Fiscal Years 2012-2022*, January 2012; Minutes from the Federal Open Market Committee's ("FOMC") meeting on April 24-25, 2010; First Quarter 2012 Survey of Professional Forecasters; Energy Information Administration's 2012 Annual Energy Outlook and The Livingston Survey, June 7, 2012.

1 The Federal Reserve Bank ("the Fed") continues to maintain the Fed Funds Rate at
2 historically low levels between 0.00% and 0.25% (see Schedules 2-1 and 2-2). Additionally, the
3 Fed decided in meetings held on June 19 and 20, 2012, to extend its bond buy-back program,
4 "Operation Twist," through the end of the year. Through this program, the Fed hopes to continue
5 to maintain, if not further reduce, already low long-term interest rates. Fed Chairman
6 Ben Bernanke bluntly indicated, "if we don't see continued improvement in the labor market
7 we'll be prepared to take additional steps." The Fed's announcement was accompanied by a
8 revised outlook for lower economic growth in the near term as compared to previous estimates.
9 The Fed now projects the economy will grow between 1.9% and 2.4% this year and less than
10 3% next year. The Fed also lowered its estimates for inflation to 1.2% to 1.7% for this year from
11 its previous projection of 1.9% to 2.0% in April. The Fed continues to communicate to the
12 markets that it will keep short-term interest rates low until late 2014.³¹ Minutes since released
13 from the June 19 and 20 meeting indicated: "Additional policy action could be warranted if the
14 economic recovery were to lose momentum, if the downside risks to the forecast become
15 sufficiently pronounced, or if inflation seemed likely to run persistently below the Committee's
16 longer-run objective."³²

17 Consequently, while there is much debate regarding the effect current monetary policy
18 may have on inflation, it appears that the Fed's primary concern is still the lack of
19 sustainable growth in the economy. Although there is also discussion of the possible impact
20 monetary policy may have on inflation in the future, the market is not factoring in a high
21 expected inflation rate in security prices. The 2012 monthly spread between 30-year Treasury
22 Inflation Protected Securities ("TIPS") and non-inflation protected Treasury bonds implies
23 investors are requiring an additional 2.25% to 2.40% return for potential inflation.³³

31 Kristina Peterson and Jon Hilsenrath, "Fed Warns of Risk to Economy, Central Bank Extends Bid to Lower Long-Term Rates, Stands Poised to Do More," *Wall Street Journal*, June 21, 2012, p. A1 and A14.

32 Kristina Peterson and Jon Hilsenrath, "Fed Weighs More Stimulus, Slow Recovery Has Central Bank on High Alert but Not Ready to Pull Trigger," *Wall Street Journal*, July 12, 2012, p. A1 and A2.

33 <http://research.stlouisfed.org/fred2/categories/22>

1 **2. Capital Market Conditions**

2 **a. Utility Debt Markets**

3 Debt markets have been very attractive for utility companies in recent months. It has
4 started to become fairly common for utilities to issue 10-year to 15-year bonds at coupons in the
5 3% range. For example, The Empire District Electric Company issued \$88 million of 15-year
6 secured debt at a coupon of 3.58% in April 2012. If one were to assume that the risk premium³⁴
7 required to invest in utility stocks rather than utility bonds was constant, then these lower utility
8 debt yields directly translate into a lower required return on equity. In other words, a lower cost
9 of debt is indicative of a lower cost of capital, all else being equal.

10 Unlike the short-term capital costs directly influenced by the Fed, long-term capital
11 costs are typically market-based. Although long-term interest rates, as measured by 30-year
12 Treasury bonds ("T-bonds"), increased to the 4% range during the November 2010 to July 2011
13 period, they have since decreased to the high 2% to 3% range for the period August 2011
14 through May 2012. (*see Schedules 4-2 and 4-3.*)

15 Long-term utility bond yields have also continued to more closely track the changes
16 in the 30-year T-bond yields in the aftermath of the financial crisis of late 2008 and early 2009.
17 Although the current spread between utility bond yields and 30-year Treasury yields is slightly
18 above the average of 1.55% since 1980 (1.91%), the absolute yield on utility bonds recently fell
19 below 5% for the first time during this prolonged period of low interest rates and slow economic
20 growth. (*see Schedules 4-1 and 4-3.*)

21 Not only has the cost of investment-grade debt capital declined considerably, but it
22 appears that the cost of non-investment grade debt has declined, as well (*see Schedule 4-6*).
23 However, the spread between investment-grade and non-investment grade debt is higher than it
24 was during the loose credit years during the middle of the previous decade (*see Schedule 4-7*).

25 **b. Utility Equity Markets**

26 For the twelve months ending December 31, 2011, the total return on the Dow Jones
27 Industrial Average was 8.38%, the total return on the Standard & Poor's 500 ("S&P 500")
28 was 2.11%, and the total return on the EEI Index of electric utilities was 19.99%. More

34 Risk Premium in this context is defined as the excess required return to invest in a company's equity rather than its debt.

1 specifically, on a non-market capitalization weighted basis, the total return for the twelve months
2 ending December 31, 2011, was 22.30% for EEI "Regulated" electric utilities, 19.52% for
3 EEI "Mostly Regulated" electric utilities and 21.36% for "Diversified" electric utilities.

4 Typically, utility indices tend to lag behind broader market indices that are increasing or
5 decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because
6 of low demand elasticity; however, utilities with significant non-regulated operations are likely
7 to be more affected by general economic trends. Although the returns of EEI's "Diversified"
8 electric utilities and "Mostly Regulated" electric utilities had lagged that of "Regulated" Utilities
9 in 2010, in 2011 the returns of all the categories were quite strong as compared to the broader
10 markets. "Regulated" utilities' total returns in 2010 were 15.75%. Adding the "Regulated"
11 utilities' returns for 2011 with those achieved in 2010, totals 38.05% over the last two years,
12 a truly spectacular couple of years for electric utility stock returns. It appears that these strong
13 returns have been driven largely by the continued decline in bond yields over the past year.
14 This is highly consistent with investors' views that utility stocks compete with bond investments
15 because they are largely considered to be bond surrogates/substitutes. In order for equilibrium to
16 return to bond prices as they relate to utility stock prices, either bond prices would decrease
17 (bond yields increase) and/or utility stock prices would increase. So far, it has been the latter.
18 The increase in utility stock price valuations does not appear to be driven by higher
19 growth expectations for the regulated utility sector. Staff's proxy group in this case contains
20 eight companies Staff used in the prior Ameren Missouri rate case, Case No. ER-2010-0036.
21 The average forward price-to-earnings ("p/e") ratio for these eight companies increased from
22 13.19x to 14.67x in just a little over a year. There are two primary drivers for higher p/e ratios,
23 higher expected growth in earnings and/or a lower cost of equity, i.e. investors willing to pay a
24 higher price per unit of earnings. In this case, it appears to be the latter because the projected
25 5-year earnings-per-share ("EPS") forecasted growth rates have actually declined since the last
26 rate case. This is a clear indication that the cost of equity has declined since KCPL's last rate
27 case, which was filed 3 months prior to Ameren Missouri's last rate case. Another indication of
28 the continued decrease in the cost of capital, especially for regulated electric utilities, is the fact
29 that the electric utility industry is trading at a premium, i.e. higher p/e ratios, to that of the
30 S&P 500. During a recent Society of Utility and Regulatory Analysts ("SURFA") conference
31 Staff attended on April 26 and 27, 2012, Greg Gordon, CFA, Senior Managing Director and

1 Partner with International Strategy and Investment, provided a presentation showing that
2 regulated electric utilities' p/e ratios have been approximately 1.2x higher than that of the
3 S&P 500. Higher p/e ratios are usually associated with higher growth companies. In the
4 aggregate, the projected growth in EPS over the next 5-years for the S&P 500 is typically 10% or
5 higher, whereas utilities' 5-year EPS growth forecasts are typically in the 5% to 6% range.
6 Clearly, this means that investors are not paying a higher p/e for electric utility stocks for growth,
7 but because of the low comparative returns offered by bonds. Utility stock returns are
8 consistently highly correlated with bond returns. The current macroeconomic environment is
9 clearly favorable to utilities in terms of a lower cost of capital for debt and equity instruments.
10 Staff believes these lower capital costs should be shared with ratepayers through lower
11 authorized returns on common equity ("ROEs").

12 In a recent Barron's 2012 Roundtable discussion, Bill Gross, founder and managing
13 director of PIMCO, indicated the following about utility returns:

14 They pay big dividends because they continually are granted a 10% return
15 on equity by regulators in a world where returns are moving much lower.
16 After earning 10% they can pay out 4% to 5% to investors.³⁵

17 Consequently, it appears the capital market environment not only continues to support the ability
18 to authorize ROEs below 10%, but it seems as if it expects them to be lowered considering the
19 current capital and economic environment.

20 **D. GPE's, KCPL's and GMO's Operations**

21 The following excerpt from GPE's Form 10-K filing with the United States Securities
22 Exchange Commission ("SEC") for the year ended December 31, 2011, provides a good
23 description of GPE's current business operations and current organizational structure:

24 Great Plains Energy, a Missouri corporation incorporated in 2001 and
25 headquartered in Kansas City, Missouri, is a public utility holding
26 company and does not own or operate any significant assets other than the
27 stock of its subsidiaries. Great Plains Energy's wholly owned direct
28 subsidiaries with operations or active subsidiaries are as follows:

- 29 • KCP&L is an integrated, regulated electric utility that provides
30 electricity to customers primarily in the states of Missouri and

35 Lauren R. Rublin, "Listen Up, Class: Here's How to Profit," *Barron's Cover*, January 16, 2012, p. 11,
http://online.barrons.com/article/SB50001424052748703535904577152932179268296.html#articleTabs_article%3D0

1 Kansas. KCP&L has one active wholly owned subsidiary, Kansas
2 City Power & Light Receivables Company (Receivables
3 Company).

4 • KCP&L Greater Missouri Operations Company (GMO) is an
5 integrated, regulated electric utility that primarily provides
6 electricity to customers in the state of Missouri. GMO also
7 provides regulated steam service to certain customers in the
8 St. Joseph, Missouri area. GMO wholly owns MPS Merchant
9 Services, Inc. (MPS Merchant), which has certain long-term
10 natural gas contracts remaining from its former non-regulated
11 trading operations.

12 Great Plains Energy's sole reportable business segment is electric utility.
13 For information regarding the revenues, income and assets attributable to
14 the electric utility business segment, see Note 21 to the consolidated
15 financial statements. Comparative financial information and discussion
16 regarding the electric utility business segment can be found in Item 7
17 Management's Discussion and Analysis of Financial Condition and
18 Results of Operations (MD&A).

19 The electric utility segment consists of KCP&L, a regulated utility, and
20 GMO's regulated utility operations which include its Missouri Public
21 Service and St. Joseph Light & Power (L&P) divisions. Electric utility
22 serves approximately 823,000 customers located in western Missouri and
23 eastern Kansas. Customers include approximately 725,000 residences,
24 96,000 commercial firms, and 2,600 industrials, municipalities and other
25 electric utilities. Electric utility's retail revenues averaged approximately
26 90% of its total operating revenues over the last three years. Wholesale
27 firm power, bulk power sales and miscellaneous electric revenues
28 accounted for the remainder of electric utility's revenues. Electric utility
29 is significantly impacted by seasonality with approximately one-third of
30 its retail revenues recorded in the third quarter. Electric utility's total
31 electric revenues were 100% of Great Plains Energy's revenues over the
32 last three years. Electric utility's net income accounted for approximately
33 115%, 111% and 104% of Great Plains Energy's income from continuing
34 operations in 2011, 2010 and 2009, respectively.

35 E. KCPL, GPE and GMO's Credit Ratings and Financing Activities

36 1. Credit Ratings

37 KCPL, GPE and GMO are currently rated by Moody's and Standard & Poor's ("S&P").
38 It is important to understand the current credit standing of the various entities, as these ratings
39 influence investors' views of the risk associated with investing in KCPL. Although Staff is not

1 estimating the cost of capital for GMO and/or GPE in this case, the influence of these entities'
2 risks on KCPL must be understood in order to estimate a fair rate of return for KCPL.

3 KCPL's Moody's senior unsecured credit rating is 'Baa2' and its S&P senior unsecured
4 credit rating is 'BBB', which are considered equivalent credit ratings based on each rating
5 agency's ratings system.³⁶ In order to allow for GMO to have an investment grade credit rating,
6 which ultimately lowered GMO's cost of debt, GPE decided to provide a guarantee on GMO's
7 debt. Moody's assigns GPE's and GMO's senior unsecured debt a rating of 'Baa3'. GPE's SEC
8 10-K Filings indicate that GMO's senior unsecured credit ratings and its commercial paper
9 ratings are supported by GPE's guarantee of GMO debt. This is noteworthy considering the fact
10 that the only other asset GPE owns is KCPL. Consequently, GMO's credit standing is indirectly
11 supported by KCPL's credit quality, which KCPL ratepayers supported during the
12 comprehensive energy plan by paying higher rates than would have been allowed under
13 traditional cost of service ratemaking. It wasn't until GPE provided an unconditional guarantee
14 to GMO's short-term credit that GMO was able to access the commercial paper markets, which
15 occurred in November 2011. S&P assigns GPE's senior unsecured debt a rating one notch lower
16 than that of KCPL and GMO. Even though GPE has been considered to be more credit worthy
17 than GMO, apparently S&P's methodology requires a one notch differential between the
18 subsidiary and the parent company. S&P and Moody's have some methodological differences
19 that can cause differences in their views on credit ratings. One key difference between S&P and
20 Moody's is in the amount of weight that each agency gives to the stand-alone subsidiary business
21 and financial risks in assigning ratings. S&P tends to rate most companies based on the
22 consolidated risk profile of the parent company, whereas Moody's tends to give at least some
23 weight to the stand-alone subsidiary risk profile in rating the subsidiary's credit risk.

24 The following is an excerpt from an April 27, 2012, S&P credit-rating report on KCPL:

25 Standard & Poor's Ratings Services bases its ratings on Kansas City
26 Power & Light Co. (KCP&L) on the consolidated credit profile of holding
27 company Great Plains Energy Inc. This includes what we consider to be
28 an "excellent" business risk profile and "aggressive" financial risk profile
29 under our criteria. Great Plains is an integrated electric utility holding
30 company that owns vertically integrated electric utilities KCP&L and
31 KCP&L Greater Missouri Operations Co. (GMO).

36 See p. 43 of Great Plain's Energy's 2011 SEC Form 10-K Filing.

1 The excellent business risk profiles for Great Plains, KCP&L, and GMO
2 reflect their status as vertically integrated, fully regulated utilities serving
3 roughly 825,000 customers in eastern Kansas and western Missouri. The
4 utilities operate an approximately 6,600-megawatt (MW) generation fleet
5 that is about 80% coal-fired. In its service territory, there have been
6 gradual signs of economic improvement, with stronger industrial sales, but
7 mixed unemployment rates; Kansas' is lower than the national average
8 and Missouri's is slightly higher. Management has improved cash flow by
9 effectively increasing revenues and cost recovery through mechanisms
10 such as a fuel-adjustment clause and the allowance of additional
11 accelerated depreciation. With a large coal concentration, timely recovery
12 of environmental compliance costs, such as KCP&L's \$615 million share
13 of LaCygne environmental retrofit project, will be important. Because
14 they are medium-size utilities with ownership in a single nuclear plant,
15 Wolf Creek, the companies' business risk profiles are hindered somewhat
16 by the probability that scrutiny and costs in the nuclear industry will
17 increase because of the accident at Fukushima Daiichi in Japan.

18 In its March 29, 2012, Credit Opinion on KCPL, Moody's provided the following
19 "Summary Rating Rationale" in its comments:

20 KCPL's Baa2 senior unsecured rating reflects its historic ability to achieve
21 generally good levels of cash flow from its utility operations in regulatory
22 jurisdictions that, on a combined basis, are viewed to be somewhat below
23 average when compared to the rest of the country; however, our
24 expectation is that the company will be able to maintain key financial
25 metrics of CFO [cash from operations] pre-WC [working capital] interest
26 coverage nearing 4.0x and CFO pre-WC to debt in the mid-teens. The
27 company's credit metrics have improved in recent years, benefitting from
28 regulatory approved rate increases and tax strategies, such as the use of
29 accelerated bonus depreciation. The primary challenge to KCPL's credit
30 profile resides in achieving timely regulatory support for the recovery of
31 increasing costs in the midst of a soft economy. This challenge is
32 intensified by the fact that KCPL has relatively few interim cost recovery
33 mechanisms, compared to other investor owned utilities around the nation.

34 The historical reliance Great Plains has placed on KCPL for dividends is
35 also a significant rating consideration. The demand for KCPL's dividend
36 has been offset somewhat by the 2008 acquisition of GMO and the 2009
37 dividend cut; however the dividend has been increasing over the past two
38 years, albeit still lower than the pre-2009 levels. On a stand-alone basis
39 GMO continues to exhibit a more leveraged capital structure than KCPL,
40 which also continues to be a consideration in our ratings since Great Plains
41 provides a downstream guarantee of the unsecured debt at GMO.

1 Although not entirely clear from the above quotes, S&P's assessment of KCPL's credit
2 quality is based its analysis of GPE's consolidated financials, which includes GMO. Moody's
3 assessment of KCPL's credit quality is based on its analysis of KCPL's financials, but it takes
4 into consideration the effect of GMO's more leveraged capital structure and the guarantee that
5 GPE provides to GMO's unsecured debt. Consequently, GPE's acquisition of GMO has
6 negatively impacted the way in which the rating agencies view KCPL's credit. While Moody's
7 does cite some regulatory issues that could cause KCPL's rating to be viewed more favorably,
8 this would not change the impact the acquisition of GMO has had on KCPL's credit standing.

9 **2. Financing Activities**

10 Staff does not believe that KCPL has been financially managed as a stand-alone
11 company, even before the acquisition of the GMO properties, but more so after the acquisition of
12 the GMO properties. For instance, GPE issued \$100 million of 6.875% debt on
13 September 20, 2007 for purposes of infusing capital into KCPL. KCPL's balance sheet reflects
14 this amount of capital as equity capital, but Staff would view this as debt for purposes of KCPL's
15 ratemaking capital structure. Issuing debt at the holding company to infuse equity into
16 subsidiaries tends to be one of Staff's primary considerations in deciding whether a subsidiary's
17 capital structure is truly "independent" and balanced to achieve a cost of capital consistent with
18 the business risk of the holding company's assets.

19 Subsequent to GPE's acquisition of the GMO assets, GPE has issued several different
20 securities to either jointly fund capital needs for both KCPL and GMO or for purposes of loaning
21 funds to GMO. GPE issued \$287.5 million of equity units on May 12, 2009, which based on
22 GPE's 2009 SEC Form 10-K Filing appears to have been pooled with several other financing
23 sources, including KCPL's Series 2009A Mortgage Bonds in the amount of \$400 million, and
24 used for a variety of needs at both KCPL and GMO. On August 13, 2010, GPE issued
25 \$250 million of 3-year unsecured debt with a 2.75% coupon. Based on internal loan documents,
26 the proceeds from this issuance were provided to GMO. On May 16, 2011, GPE issued
27 \$350 million of 10-year unsecured debt with a 4.85% coupon. Based on internal loan
28 documents, the proceeds from this issuance were provided to GMO. On March 19, 2012, GPE
29 issued \$287.5 million of 10-year unsecured debt with a 5.292% coupon. Although this financing
30 was tied to the equity units that were previously allocated to both KCPL and GMO, because the

1 proceeds from this debt issuance were apparently used to partially refinance a GMO
2 \$500 million debt issuance that matured on July 2, 2012, this debt was assigned to GMO through
3 an internal loan agreement.

4 KCPL has issued two debt financings subsequent to GPE's acquisition of the GMO
5 assets. On March 24, 2009, KCPL issued \$400 million of 10-year mortgage bonds at a coupon
6 of 7.15%. On September 20, 2011, KCPL issued another \$400 million of debt, but this time it
7 was unsecured debt with a 30-year term at a coupon of 5.30%.

8 The weighted average coupon cost of debt assigned to GMO subsequent to its acquisition
9 by GPE has been 4.402%, whereas the weighted average coupon cost of debt assigned to KCPL
10 has been 6.23%. Although some of this difference has to do with the timing of the debt
11 issuances, this wide difference in cost of debt seems inherently unfair to KCPL ratepayers
12 considering they have provided the credit support for KCPL during the period of its
13 comprehensive energy plan, which ultimately benefited GPE's credit quality and has made it
14 possible to enhance GMO's credit quality.

15 **F. Cost of Capital**

16 In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an
17 appropriate ratemaking capital structure, (2) the Company's embedded cost of debt and preferred
18 stock, and (3) the Company's cost of common equity.

19 **1. Capital Structure**

20 Schedule 5 presents GPE's historical capital structures in dollar terms and percentage
21 terms for the past five years. As can be derived from these historical capital structures, the
22 current proposed ratemaking capital structure for KCPL contains more equity than GPE's
23 year-end equity ratios for the last four years. Staff understands that this is primarily due to the
24 conversion of GPE's equity units into traditional common equity during the second quarter
25 of 2012. In fact, it is for this reason that Staff proposes the use of financial data through
26 June 30, 2012, for purposes of setting the allowed ROR in the general rate case. Before GPE
27 issued the equity units, it typically had a common equity ratio close to 50%. Consequently, Staff
28 has no reason at this time to dispute a ratemaking capital structure that has 52.42% equity ratio.
29 However, being that there is a true-up scheduled for this proceeding, Staff can evaluate all

1 known data through at least the true-up period to verify the reasonableness of the current
2 proposed ratemaking capital structure.

3 Staff believes that the consolidated-basis capital structure of KCPL's publicly-traded
4 parent, GPE, as of June 30, 2012, is most appropriate for use as the rate making capital structure
5 in this rate proceeding (*see* Schedule 6-1). Although this date is beyond the agreed upon updated
6 test year of March 31, 2012, because of unique and significant financing activities occurring
7 within GPE that were scheduled to be completed on or around June 30, 2012, this capital
8 structure seems reasonable. This capital structure is appropriate because it reflects KCPL's
9 actual financing and because the risk embedded in GPE's capital structure affects KCPL's credit
10 rating. Staff's recommended KCPL ratemaking capital structure consists of ** _____ **
11 common equity, ** _____ ** long-term debt, and ** _____ ** preferred stock.³⁷

12 **2. Embedded Cost of Debt and Preferred Stock**

13 In KCPL's most recent rate case, Case No. ER-2010-0355, Staff recommended applying
14 KCPL's embedded cost of long-term debt to GPE's consolidated capital structure in the general
15 rate case. However, after GPE issued debt between the updated test year of June 30, 2010, and
16 the true-up period of December 31, 2010, KCPL and GMO decided to assign the GPE debt to
17 GMO for purposes of updating the ROR recommendations. In response, Staff decided if the
18 Commission accepted the inclusion of the GPE debt for purposes of the true-up, then the
19 Commission should authorize a ROR for KCPL and GMO by applying GPE's consolidated
20 adjusted cost of debt to both KCPL and GMO for purposes of the authorized ROR for each
21 company. Although the Commission ultimately accepted the approach proposed by KCPL and
22 GMO, Staff believes that further GPE financing decisions since the last rate case (explained in
23 Section E. 2. of this Report) provide additional support to apply GPE's adjusted consolidated
24 cost of debt to both KCPL and GMO, especially when considering the fact that the
25 Commission's Report and Order in Case No. EM-2007-0374 required KCPL ratepayers to be
26 held harmless from paying higher capital costs as result of financial effects of credit downgrades
27 due to the acquisition of the GMO properties.

28 Although Staff has already explained GPE's, KCPL's and GMO's credit ratings and
29 financing activities to some extent, for purposes of relating this information to Staff's position of

37 KCPL's response to Staff DR No. 194 and SEC 2009 10-K Filing.

1 applying GPE's consolidated cost of debt to KCPL and GMO for purposes of setting the allowed
2 ROR, Staff will simplify and summarize the inherent inequity with the Company's proposed
3 approach to the cost of debt. Before GPE acquired Aquila, Inc. (now GMO), Aquila's credit
4 rating was considered a "junk" rating. This caused Aquila to incur higher costs of debt when it
5 needed to issue debt for its capital needs. However, when GPE agreed to acquire Aquila, it
6 provided a guarantee of Aquila's debt, which caused rating agencies to raise Aquila's ratings to
7 investment grade status. This investment grade status allowed for lower debt costs for not only
8 debt outstanding at Aquila at the time (\$500 million of debt that had a coupon of 14.875% before
9 the acquisition was reduced to 11.875% in consideration of the investment grade rating), but for
10 new long-term and short-term debt issued on behalf of or by the entity now named GMO. GPE's
11 ability to enhance GMO's credit rating was made possible by KCPL's credit profile as this
12 formed the basis for GPE's investment grade credit rating. KCPL's rates were allowed to be set
13 higher than normally would have been the case under traditional cost of service ratemaking
14 during the period of the comprehensive energy plan, which covered the period in which capital
15 expenditures were made for construction of Iatan II and environmental retrofits to Iatan I. KCPL
16 was specifically allowed extra cash flow through increased rates during this period of
17 construction to specifically target financial ratio benchmarks consistent with a 'BBB+' credit
18 rating. However, during this period of higher capital expenditures, GPE decided to make a major
19 acquisition, which placed further strain on its credit profile and the flexibility it had to provide
20 cost effective capital for KCPL. This was magnified due to the financial crises that occurred in
21 late 2008 and early 2009. In fact, GPE had so little financial flexibility during the financial crisis
22 that it was forced to issue high cost equity units because it was on the verge of being downgraded
23 to below investment grade status, which would have had a significant impact on the cost of
24 capital for all of GPE's operations.

25 For the foregoing reasons, Staff believes it is important to scrutinize the corporate
26 financing activities of GPE and its subsidiaries in order to ensure a reasonable cost of debt is
27 charged to the utility operations and ultimately ratepayers through the allowed ROR. While
28 Staff has concerns about whether the cost of debt issued by GPE is consistent with the cost either
29 KCPL or GMO could have achieved without being exposed to the business risk and lingering
30 financial risk caused by Aquila's failed non-regulated investments, Staff's biggest concern is
31 with how GPE is managing the tenor and type of debt offerings for GMO and KCPL. For

1 example, on August 13, 2010, GPE issued \$250 million of 3-year debt at a cost of 2.75%. GPE
2 assigned this debt to GMO for purposes of its requested embedded cost of debt. However, only a
3 year later, on September 20, 2011, KCPL issued \$400 million of 30-year debt at a cost of 5.30%.
4 Staff is not aware of why GPE would decide it was proper to issue 3-year debt for GMO, which
5 carries a much lower cost, and 30-year debt for KCPL, which has a cost that is 2.55% higher. If
6 KCPL had issued \$400 million of debt at a 3-year tenor with a coupon similar to that of GPE
7 (although KCPL would likely get a lower coupon because of its more favorable Moody's
8 unsecured credit rating), then KCPL ratepayers would pay \$10.2 million dollars less a year in
9 interest expense. During the same year KCPL issued \$400 million of 30-year notes, GPE issued
10 \$350 million of 10-year notes at a coupon of 4.85%. Although the embedded cost of the GPE
11 notes ultimately ended up being higher due to interest rate swaps for hedging purposes, for some
12 reason, GPE again decided to issue shorter-tenor notes for the financing it issued at the holding
13 company compared to the notes issued at KCPL.

14 Consequently, not only is it likely that KCPL is paying a higher coupon on its debt due to
15 its affiliation with GMO, but GPE is issuing longer-term debt at KCPL as compared to that
16 issued for GMO, which comes at a higher cost. While it is difficult to ascertain exactly how
17 much lower KCPL's debt costs could be absent this affiliation, Staff believes considering the fact
18 that GPE introduced this circumstance through corporate acquisition activities, which causes
19 uncertainty regarding higher capital costs KCPL ratepayers are paying, it is incumbent to error
20 on the side of conservatism in estimating the cost of debt that should be allowed in the ROR.

21 Not only does Staff recommend a consolidated cost of debt be applied to both GMO and
22 KCPL, but Staff also believes the cost of the debt issued by GPE should be adjusted downward
23 to consider the fact that it is probable that KCPL and GMO could have received a lower coupon
24 on this debt if it was issued with a 'BBB' unsecured debt rating, which is consistent with
25 KCPL's current unsecured rating and the rating Aquila had before its non-regulated business
26 failures caused its ratings to fall precipitously to as low as 'CCC+', which was only one category
27 above default.

28 Staff made downward adjustments to the coupon rates of all three debt issuances GPE
29 made subsequent to its purchase of the GMO assets. If the GMO assets had not been impacted
30 by the Aquila legacy debt, then it is likely that GPE would not have had to provide a guarantee
31 for debt associated with GMO's regulated utility operations because of its low business risk. In

1 all likelihood, any subsequent unsecured debt could have been issued at a 'BBB' unsecured debt
2 rating rather than the option GPE used, which was to issue holding company debt. For purposes
3 of its adjustments, Staff simply applied the average 'BBB' utility debt yield for the months in
4 which GPE issued the three notes in question. Staff matched the tenor of the actual debt with the
5 tenor for the month in which the bond was issued. Staff adjusted the 2.75% coupon for the
6 \$250 million debt issued on August 13, 2010, to 2.00%. Staff adjusted the 4.85% coupon for the
7 \$350 million debt issued on May 16, 2011, to 4.70%. Staff adjusted the 5.292% coupon for the
8 \$287.5 million debt issued on March 19, 2012, to 4.25%.³⁸ After making all these adjustments
9 and consolidating all GPE debt, this results in final consolidated cost of debt estimate of
10 ** _____ **. Staff recommends that this cost of debt be applied to GPE's consolidated capital
11 structure for purposes of setting KCPL's allowed ROR in this case (see Schedule 6-1).

12 **3. Cost of Common Equity**

13 Staff determined KCPL's cost of common equity through a comparable company cost-of-
14 equity analysis of a proxy group of 10 companies using the DCF method. Additionally, Staff
15 used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its
16 recommendations.

17 **a. The Proxy Group**

18 First, Staff formed a group of comparable companies for the commensurate
19 return analysis. Starting with 55 market-traded electric utilities, Staff applied a number of
20 criteria to develop a proxy group comparable in risk to KCPL's regulated electric utility
21 operations (*see* Schedule 7). Staff decided to add one additional criterion in this case as
22 compared to KCPL's last rate case. Staff added a criterion to screen out companies that do not
23 have an equivalent S&P business risk profile as KCPL, which is currently 'Excellent.' Staff
24 believes it was important to add this criterion to further screen utility companies that may have
25 non-regulated operations that are impacting the parent company's business risk even though they
26 were classified as "regulated" by EEI. For example, although EEI classifies Ameren as a
27 "regulated" electric utility, many investment analysts, such as Goldman Sachs, consider Ameren
28 to be a diversified company. Staff's criteria is as follows:

38 Staff used BondsOnline for average utility bond yields for the appropriate tenor and rating.

- 1 1. Classified as an electric utility by Value Line (55 companies);
- 2 2. Publicly-traded stock;
- 3 3. Followed by EEI and classified by EEI as a regulated electric
- 4 utility (19 companies eliminated, 36 remaining);
- 5 4. Followed by AUS and reporting at least 70% of revenues from
- 6 electric operations (11 companies eliminated, 25 remaining);
- 7 5. Ten years of Value Line historical growth data available
- 8 (3 companies eliminated, 22 remaining);
- 9 6. No reduced dividend since 2009 (2 companies eliminated,
- 10 20 remaining);
- 11 7. Projected growth available from Value Line and Reuters
- 12 (1 company eliminated, 19 remaining);
- 13 8. At least investment grade credit rating (3 companies eliminated,
- 14 16 remaining);
- 15 9. Company-owned generating assets (0 companies eliminated,
- 16 16 remaining);
- 17 10. Rated an 'Excellent' Business Risk Profile by S&P (4 companies
- 18 eliminated, 12)
- 19 11. No significant merger or acquisition announced in last 3 years
- 20 (2 companies eliminated, 10 remaining).

21 This final group of 10 publicly-traded electric utility companies ("the comparables") was
22 used as a proxy group to estimate the cost of common equity for KCPL's regulated electric
23 utility operations. The comparables are listed on Schedule 8.

24 **b. The Constant-growth DCF**

25 Next, Staff calculated KCPL's cost of common equity applying values derived from the
26 proxy group to the constant-growth DCF model. The constant-growth DCF model is widely
27 used by investors to evaluate stable-growth investment opportunities, such as regulated utility
28 companies. The constant-growth version of the model is usually considered appropriate for

1 mature industries such as the regulated utility industry.³⁹ It may be expressed algebraically as
2 follows:

$$3 \quad k = D_1/P_0 + g$$

4 Where: k is the cost of equity;
5 D_1 is the expected next 12 months dividend;
6 P_0 is the current price of the stock; and
7 g is the dividend growth rate.

8 The term D_1/P_0 , the expected next 12-months' dividend divided by current share price,
9 is the dividend yield. Staff calculated the dividend yield for each of the comparable
10 companies by dividing the weighted average of the 2012 and 2013 Value Line projected
11 dividend per share (see Schedule 11) by the monthly high/low average stock price for the
12 three months ending May 31, 2012 (see Schedule 10).⁴⁰ Staff uses the above-described stock
13 price because it reflects current market expectations. The projected average dividend yield for
14 the ten comparable companies is 4.1%, unadjusted for quarterly compounding.

15 i. The Inputs

16 In the DCF method, the cost of equity is the sum of the dividend yield and a
17 growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a
18 growth rate, Staff considered both the actual dividends per share ("DPS"), EPS and book value
19 per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and
20 BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be quite
21 volatile.⁴¹ Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for

39 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.

40 The monthly high/low averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P_0 is calculated by averaging the highest and the lowest price for each month during the selected period.

41 Schedule 9-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 9-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

1 each of the comparable companies over the next five years (*see* Schedule 9-3). While more
2 stable than the historical growth rates, Staff still found a relatively wide dispersion in projected
3 EPS growth (3.00% to 8.00%). Equity analysts' earnings estimates on *Reuters.com* also showed
4 a wide dispersion of 3.00% to 6.96%. The average projected 5-year EPS annual compound
5 growth rate estimates yielded a growth rate of 5.40%, which Staff believes is not sustainable
6 (*see* Schedule 9-4, Column 6).

7 Due to the current volatility and wide dispersions present in Staff's analysis of historical
8 and projected DPS, EPS, and BVPS, Staff only gave this data limited weight in estimating a
9 reasonable growth rate for its single-stage DCF analysis. For reasons Staff will discuss in more
10 detail below, use of equity analysts' forecasts of 5-year EPS growth is not reasonable in the
11 context of estimating the cost of equity using a single-stage DCF methodology. However, if
12 Staff uses growth rates consistent with these estimates in its constant-growth DCF, the cost of
13 equity indication is approximately 9.10% to 9.60%.

14 Although use of equity analysts' 5-year EPS growth forecasts as a constant growth rate is
15 easy and popular in utility ratemaking, investors do not assume their utility investments can grow
16 at this rate into perpetuity when estimating a fair price to pay for utility stocks. Not only does
17 practical investment analysis prove this wrong, but empirical evidence proves that EPS growth
18 for the electric utility industry has never achieved these lofty growth rates over a long period.
19 This was true even during the growth stage of the electric utility industry.

20 According to data published in the *2003 Mergent Public Utility and Transportation*
21 *Manual*, electric utility growth rates have been approximately half of achieved GDP growth for
22 the period 1947 through 1999.⁴² As noted previously, long-term GDP growth is expected to be
23 in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric
24 utilities should be much lower than the projected 5-year EPS growth rates.

25 Staff also analyzed the growth of electric utilities identified by Value Line as
26 *Central* region electric utilities over the period 1968 through 1999, a shorter, more recent period
27 based on data from Value Line rather than Mergent (Staff will explain this analysis in more
28 detail when explaining its multi-stage DCF analysis). Staff's analysis of this data revealed that
29 the actual realized growth of these electric utilities was less than *half* of GDP growth over this
30 time period. In addition, this analysis also showed that during a period of much higher nominal

⁴² 2003 Mergent *Public Utility & Transportation Manual*, p. a15 – a18.

1 GDP growth, the *Central* region electric utilities' EPS, DPS and BVPS grew in the range of
2 3.18% to 3.99% (*see* Schedules 14-1 through 14-4). Because the constant-growth DCF will only
3 provide reliable results if the growth rate is within 1.0% to 2.0% of a sustainable long-term
4 industry growth rate,⁴³ Staff decided its analysis of historical growth in the electric utility
5 industry could only marginally support a more aggressive growth rate range of 5.0% to 5.5%.
6 Staff emphasizes that it believes this growth rate is higher than what investors expect for the
7 electric utility industry considering that it is higher than the expected long-term GDP growth of
8 approximately 4.5%. Although there have been periods in which electric utility aggregate
9 nominal growth has been higher than that of nominal GDP growth, this has not occurred for the
10 last 20 years (*see* Schedule 12). On a per share basis, which is the focus of investors, electric
11 utility growth has been much lower. Because a multi-stage DCF analysis allows investors to
12 address non-constant growth expectations, Staff places primary weight on its multi-stage
13 DCF analysis in this case.

14 Using the constant-growth DCF model and the inputs described above -- a projected
15 dividend yield of 4.1% and a growth rate range of 5.0% to 5.5% -- a cost of common equity of
16 9.1% to 9.6% is implied (*see* Schedule 11).

17 c. The Multi-stage DCF

18 i. Overview

19 The constant-growth DCF model may not yield reliable results if industry and/or
20 economic circumstances cause expected near-term growth rates to be inconsistent with
21 sustainable perpetual growth rates.⁴⁴ Staff believes this condition currently exists for the electric
22 utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give
23 this estimate primary weight in its estimated cost of equity for KCPL.

24 A multi-stage DCF may use either two or more growth stages, depending on the situation
25 being modeled. In any case, the last stage must use a sustainable rate as it is considered to last
26 into perpetuity. In fact, in Staff's experience, most DCF analyses do not assume a growth rate

43 Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset*, University Edition, John Wiley & Sons, Inc., 1996, p. 193.

44 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.

1 much higher than the expected rate of inflation, currently 2.0% to 2.5%. The ability of a
2 multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by
3 the analyst using a reasonable growth rate for the final stage because this rate is assumed to last
4 in perpetuity. Where three stages are used, the second stage is generally a transitional phase
5 between the high growth first stage and the constant growth final stage.⁴⁵

6 In the present case, Staff used a three-stage DCF approach, the stages being years 1-5,
7 years 6-10, and years 11 to infinity.⁴⁶ For stage one, Staff gave full weight to the analysts'
8 five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model,
9 because Staff understands that these projections are designed to represent expectations over this
10 same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one
11 level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate
12 range of 3.00% to 4.00%; mid-point 3.50% (see Schedules 13-1 through 13-3). Based on this set
13 of assumptions, Staff's estimated cost of equity for the proxy group is approximately 7.80% to
14 8.60%, mid-point of 8.20%.

15 **ii. Stage one**

16 The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast
17 cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of
18 a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next
19 several years. However, in the context of discounting expected future DPS, it is often the case
20 that a compound growth rate is applied to the current DPS to estimate the expected DPS over the
21 next several years. Although it is rare for a company to tie its targeted DPS growth rate directly
22 to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts
23 are widely available and may provide some insight on expected DPS, Staff decided to use these
24 growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has
25 never seen an investment analysis of a utility company that used 5-year EPS forecasts for
26 purposes of estimating the growth in DPS in a single-stage, constant-growth DCF or for the final
27 stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year
28 EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in

⁴⁵ 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.

⁴⁶ In practice, Staff extended the third stage only to year 200.

1 their own analyses should be proof in and of itself that stock prices do not reflect this
2 assumption. Consequently, Staff limited its use of these growth rates to the first five years of its
3 analysis, the very period these growth rates are intended to cover.

4 **iii. Stage two**

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

11 **iv. Stage three**

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

16 Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to
17 the assumed perpetual growth rate. In the last KCPL rate case, the Commission indicated that
18 Staff’s growth rate estimates could not be confirmed by government or industry statistics.⁴⁷ Staff
19 will provide the Commission with data from the government, industry and academics that
20 supports the reasonableness, if not aggressiveness, of its estimated perpetual growth rate of
21 3.00% to 4.00%. Staff will first explain the methodology it used to determine that a 3.00% to
22 4.00% growth rate is a reasonable proxy for perpetual growth for its electric utility comparable
23 group. Staff will then discuss the additional research it performed to conclude that it is not
24 reasonable to assume electric utilities can grow at the same rate as nominal GDP in perpetuity.

25 The Financial Analysis Department has access to Value Line data on *Central* region
26 electric utility companies dating back to 1968.⁴⁸ Although Staff has access to current electric

⁴⁷ *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in Its Charges for Electric Service to Continue the Implementation of Its Regulatory Plan*, Report and Order, Missouri Public Service Commission, File No. ER-2010-0355, April 12, 2011, p. 118.

⁴⁸ 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

1 utility financial data for all regions of the United States (*Central, East and West*), Staff's access
2 to older data from the *East and West* regions is limited. Staff believes it is important to analyze
3 electric utility industry financial data to at least the early 1970s since this was approximately the
4 beginning of the last large construction cycle for the electric utility industry.⁴⁹ Because 1968 is
5 consistent with the starting point of the last construction cycle, Staff decided to capture data
6 starting in that year. Ideally, Staff would have analyzed data through the beginning of the
7 current construction cycle, which started approximately during the middle of the past decade, but
8 because many electric utility companies diversified into non-regulated merchant and trading
9 operations towards the end of the 1990s and there was much consolidation during this same
10 period, this noise causes any study relying on this more recent data to be less reliable in
11 evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the
12 electric industry occurred subsequent to the Enron, Inc., bankruptcy in December 2001.
13 Considering that much of this disruption was caused by deregulation, Staff does not consider the
14 information during this period to be informative for understanding investors' growth
15 expectations for regulated electric utility operations.

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

25 Staff's analysis of these electric utility companies' data over the last electric utility
26 construction cycle indicates that average long-term growth slowly increased through the
27 late 1980s and early 1990s and declined for the rest of the 1990s. The growth rates are based on
28 Staff's calculation of a simple average of all of the companies' growth rates over this period.

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.

⁴⁹ 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).

1 Because a simple average gives each company equal weight, Staff believes this approach is
2 appropriate because it does not introduce size bias. As can be seen in the attached Schedules,
3 the rolling average 10-year compound EPS growth rate for this period was 3.62%; the rolling
4 10-year compound DPS growth rate was 3.99%; the rolling 10-year compound BVPS growth
5 rate was 3.18%; and the overall average for DPS, EPS and BVPS was 3.59%.

6 However, it is important to understand that these growth rates were achieved during a
7 much more robust economic environment than the U.S. is expected to achieve in the foreseeable
8 future. Also, it is interesting to note that the average growth rate for these electric utilities was
9 less than 50% of GDP growth over the same period.

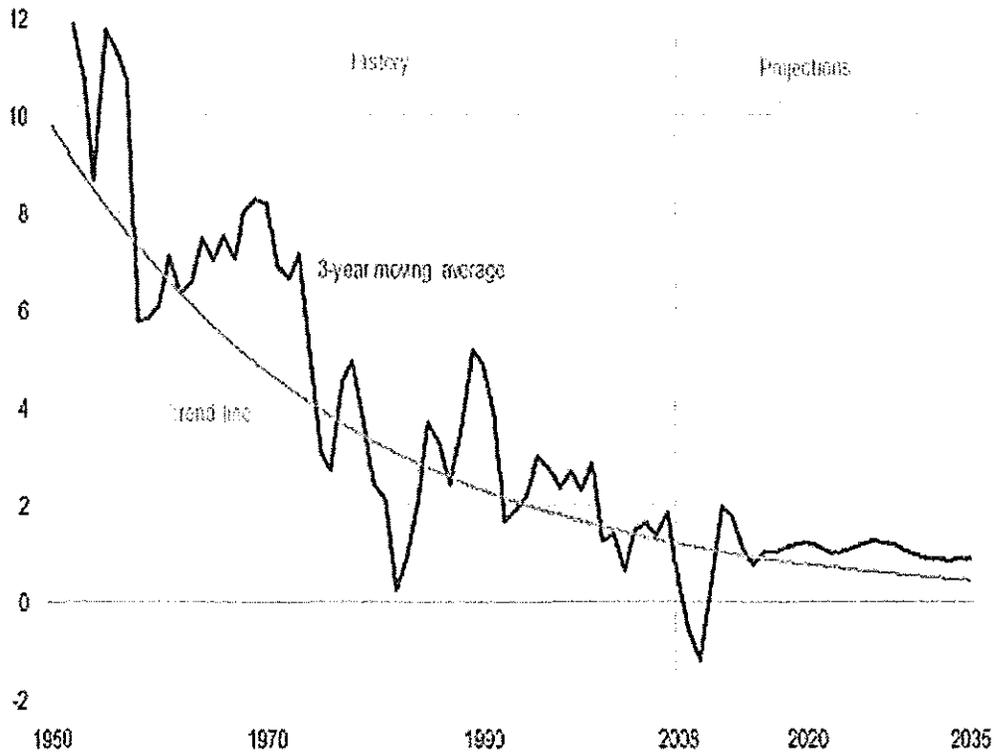
10 Also attached is Staff Schedule 15, which shows Staff's study of actual realized
11 long-term growth of electric utility companies for the period 1947 through 1999 as published
12 in the 2003 Mergent *Public Utility and Transportation Manual*. Although Staff has had problems
13 replicating this data, Staff believes this information is still useful in evaluating the trends in
14 growth rates for the electric utility industry, which shows a downward trend in growth over the
15 last 30 years. This data also demonstrates that electric utility companies' EPS and DPS do not
16 grow at the same rate as GDP over the long-term.

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

18 In the Commission's Report and Order in KCPL's last rate case, Case No.
19 ER-2010-0355, the Commission dismissed Staff's growth rates because they were not supported
20 by government and industry data. As explained in the previous section of this report, Staff is
21 using the same perpetual growth rates used in the last rate case based on data analyzed for the
22 period 1968 through 1999. Staff considers this period to be logical considering it captured the
23 last building cycle in the electric utility industry, which started in the 1970s, peaked in the 1980s
24 and fell through the 1990s. In fact, growth rates for this period would likely be considered
25 higher than those expected in the future due to the fact that this period encapsulated a period of
26 higher demand for electricity as illustrated in the following Energy Information Administration
27 ("EIA") chart provided in its 2011 Annual Energy Outlook:

1

Figure 59. U.S. electricity demand growth 1950-2035
percent, 3-year moving average



2

3

Source: Energy Information Administration's 2011 Annual Energy Outlook

4

To meet this load growth, electric utilities made significant investments in generating capacity in the late 70's and early 80's.

6

In hopes of addressing the Commission's concerns about the lack of sufficient supporting government and industry data, Staff researched a variety of freely-available, web-based sources to determine if information is available that would allow for a broader and more extensive evaluation of actual realized growth in at least the broader utilities sector (i.e. electric, natural gas and water), if not specifically the electric utility industry. However, this information is not freely-available. Access to this information would require subscriptions to sources, such as Compustat, Factset, KnowledgeReuters and Ned Davis Research, which are often utilized by institutional investors. If the Commission would like Staff to perform a more comprehensive analysis, then Staff would need to further research the best sources to which to subscribe in order

14

1 to obtain access to the relevant information at a reasonable cost. However, Staff was able to
2 review and analyze an extensive amount of data comparing utility aggregate growth rates to per
3 share growth rates that demonstrates that Staff's estimated perpetual growth rate of 3% to 4% is
4 probably too high.

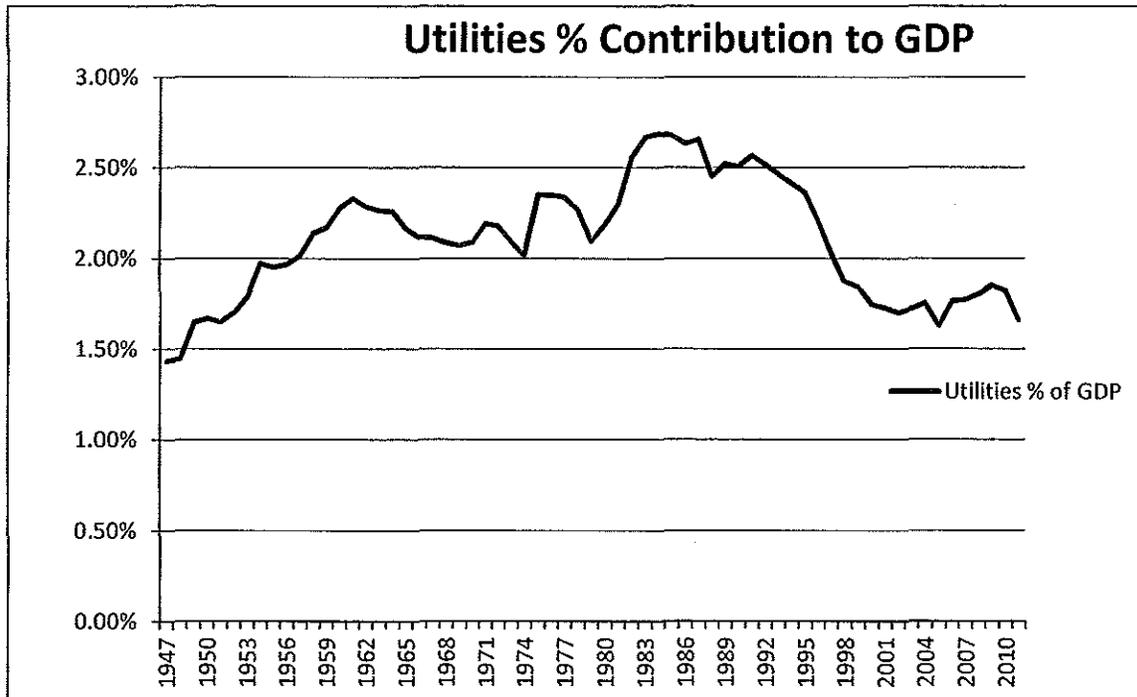
5 The other ROR witnesses in the last rate case used estimates of long-term nominal GDP
6 growth rates for their perpetual growth rates.⁵⁰ Specifically, the Company witness provided his
7 own projected nominal GDP growth rate by analyzing historical data, whereas the Missouri
8 Industrial Energy Consumers, The Midwest Energy Users Association and United States
9 Department of Energy witness relied on the *Blue Chip Economic Forecasts*. While there may be
10 some logic for this approach for early to middle-stage companies, there is little logic for this
11 approach for industries that are in the mature to declining stages of growth. Also, the use of
12 nominal GDP growth does not take into consideration the fact that existing shareholders do not
13 realize the aggregate growth of an industry due to the dilution caused by issuance of new equity.

14 Staff researched data provided by the Bureau of Economic Analysis ("BEA") on
15 GDP growth by industry and by components. Although the use of projected aggregate GDP data
16 is expedient and convenient, this comes at the expense of a reliable cost of equity estimate. Staff
17 does not believe investors would sacrifice reliability for expediency when making investment
18 decisions. Several industries contribute to the aggregate GDP of the U.S. economy. Currently,
19 the BEA compiles data based on the North American Industry Classification System of the
20 United States ("NAICS"). Although the NAICS definitions include more refined utility
21 classifications, the BEA only reports data for the aggregate Utilities definition, which is assigned
22 NAICS Code 22. Although this is an aggregate codification, Staff believes investors would rely
23 on data specific to the utilities sector rather than that of the aggregate economy when estimating
24 the potential growth of their utility investments. Better yet, Staff believes investors would drill
25 down into the detail of the contribution of utilities' profits to GDP rather than that of *total value*
26 *added* to GDP.

27 According to Staff's analysis of the utilities industry data available since 1947, as
28 illustrated below and in Schedule 16, the utilities industry made up less than 2% of GDP until the
29 middle 1950s and then gradually increased to just shy of 3% of GDP in the 1980s and 1990s.

⁵⁰ Nominal GDP includes economic growth caused by real factors, such as productivity improvements, technological advances and other factors that improve a country's overall standard of living, but it also includes expansion of the economy due solely to increases in the prices of goods and services, which is simply inflation.

1 However, since the late 1990s, utilities' contribution to GDP has declined to below 2% and has
2 since leveled off.



3

4 Although it appears that utilities may contribute less to GDP going forward, if utilities
5 continue to contribute the same percentage to GDP as they have for the last few years, then it is
6 possible that the aggregate growth of *total value added* may be similar to that of aggregate GDP
7 growth. It is extremely important to understand that this data represents *total value added* to
8 GDP, not just aggregate earnings to shareholders or, more importantly, EPS and/or DPS, which
9 is the primary focus of investors. Regardless, this data corroborates the data Staff provided in
10 the last KCPL rate case, which showed increases in EPS and DPS growth rates through the late
11 1980s and declining EPS and DPS growth rates from that point through at least 1999. Staff did
12 not provide data for the period after 1999 because company-specific data lacked continuity due
13 to restructurings, mergers and acquisitions and the Enron debacle. The GDP data for the period
14 after 1999 shows the growth rate of at least *total value added* to GDP by utilities is not declining
15 to the extent it had been for the previous decade. If utilities are to be able to continue to stop this
16 decline, they will need to determine how to add value to an economy that is not nearly as
17 energy-intensive as it once was and is in fact looking at ways to cut back on energy use.

1 Although the GDP data does show some relationship between aggregate GDP growth and
2 utilities' contribution to aggregate GDP growth, it is interesting to note that the *total value added*
3 from the utilities' sector grew faster than aggregate GDP for a period, but during its decline it
4 grew at a rate slower than GDP on an aggregate basis. While Staff has not quantified the gross
5 capital invested in the utility industry during the period of growth, it is generally recognized that
6 the electric utility industry required significant capital investment in the late 1970s and early
7 1980s due to the construction of large generation facilities. Although the electric utility industry
8 is currently in another construction cycle, it is not driven by demand growth, but by
9 environmental requirements, transmission investments, and replacement of aging and/or
10 polluting generating facilities. Because this construction cycle is not driven by growing demand,
11 it would not appear that this growth could be sustainable, otherwise this investment would cause
12 rates to spiral out of control, if allowed by commissions.

13 The *total value added* measurement of GDP includes increases to GDP caused by
14 inflation. Because the period analyzed by Staff includes a high inflationary period during the
15 late 1970s and early 1980s, it is misleading to assume utilities may be able to contribute as much
16 to real GDP as it may to nominal GDP. Consequently, Staff also analyzed real GDP growth as
17 compared to the utility industry's real growth for the period 1947 through 2011
18 (*see* Schedule 17). Staff's growth rate calculations are based on the same methodology Staff
19 used to evaluate the long-term growth of the *Central* region electric utilities. For 10-year periods
20 up to 1979, the utility industry's real growth rates were higher than that of GDP. However, the
21 utility industry's 10-year real growth rates were much lower than real GDP 10-year growth rates
22 during the 1980s. This is most likely due to the tremendous amount of capital invested in the
23 electric utility industry during the building cycle that occurred during this period. Real utility
24 growth grew at a higher rate than that of real GDP for a brief period through the
25 early-to-mid 90s, but since this time the real growth rate of utilities has been lower than that of
26 real GDP growth. This would seem to imply that the utility industry is possibly in a state of
27 decline or at least in another building cycle. If the latter, then this may cause investors to project
28 higher aggregate growth over the near-term, but because this construction cycle is not being
29 driven by demand growth, it seems illogical that investors would expect a growth rate higher
30 than that achieved during the last construction cycle.

1 The utility industry's contribution to GDP discussed above is based on the *value added*,
2 both real and nominal, of the industry, which is the sum of compensation to employees, taxes on
3 production and imports less subsidies, and gross operating surplus. Gross operating surplus
4 includes consumption of fixed capital ("CFC"), proprietors' income, corporate profits, and
5 business current transfer payments (net).⁵¹ Although gross operating surplus could be used as a
6 proxy for utilities' capital contribution to GDP, it seems the more relevant data would be that of
7 corporate profits considering we are attempting to estimate the growth of shareholder value.
8 Again, however, it should be noted that the corporate profit figure is an aggregate figure, which
9 does not consider the dilution caused by the issuance of new equity. Although utility corporate
10 profits would seem to be the most relevant data for the purposes of evaluating utility growth,
11 unfortunately, the BEA website does not provide this data for the aggregate utility industry for
12 years prior to 1998. However, the BEA website does provide this data for SIC code 49 for
13 electric, gas and sanitary services. Although this code includes industries other than utilities, it is
14 still more refined than that of aggregate corporate profits for all industries that contribute to
15 GDP growth. As with utility industry's *total value added* contribution to GDP, corporate profits
16 peaked in the 1980s and have since declined (*see* Schedule 18). Staff was surprised to find that
17 growth in corporate profits for SIC code 49 was as high as 20% in the early 1980s. This seemed
18 to contradict the much lower electric utility industry per share growth rates published in the
19 2003 Moody's Public Utility Manual. Additionally, the growth rates in utility value added to
20 GDP were also higher than electric utility industry per share growth rates, although not as much
21 as the corporate profit growth rates. Because Staff analyzed a proxy group of Value Line
22 *Central* region electric utilities over this same period, Staff decided to compare these per share
23 growth rates to corporate profit growth and utility value added growth (*see* Schedule 19).
24 Although these per share growth rates were not as low those of the Moody's index, they were
25 still much lower than the growth of corporate profits and utility value added. The fact that
26 electric utilities had to issue equity to fund capital expenditures during this period probably
27 explains the difference in these growth rates.

28 The issuance of additional equity creates a dilution of earnings to existing shareholders.
29 Because the utility industry has historically had a high dividend payout ratio (DPS/EPS), anytime
30 it needs to make large investments, it needs to issue new capital in the form of debt and equity.

⁵¹ <http://www.bea.gov/glossary/glossary.cfm>.

1 This can cause a vicious cycle for utility companies as described in *The Analysis and Use of*
2 *Financial Statements*, 1998, by Gerald I. White, Ashwinpaul C. Sondhi and Dov Fried:

3 Although this example may appear unrealistic, it is a reasonable
4 description of the plight of public utility companies (gas, electric, water)
5 in the United States. To attract investors, these firms historically paid out
6 most of their earnings as dividends. To finance growth, they periodically
7 sold additional common shares. As a result, EPS growth rates were low.
8 These firms were trapped in a vicious cycle. If they reduced their
9 dividend rates, their EPS growth rates would rise, and they might be
10 considered growth companies rather than bond substitutes.

11 Staff tested this theory by analyzing the aggregate growth rates of its Value Line
12 *Central* region electric utility proxy group for the same period in which per share growth rates
13 were analyzed (1969 – 1998). Staff found that the aggregate growth of earnings, dividends and
14 book value of this proxy group was extremely tightly correlated (99%) to that of the utility
15 industry's contribution to GDP growth. In fact, this proved to be a much tighter correlation than
16 that of utility corporate profits, which had a correlation of 72%. Although aggregate utility
17 growth has been lower than GDP growth since the early 1990s, the aggregate proxy group
18 financial growth for the period 1968 through 1999 was 97% correlated to overall GDP growth.

19 While Staff believes the above correlations are more than coincidence, if Staff had access
20 to more historical data for not only the *Central* region electric utilities, but also the *East* and
21 *West* region electric utilities, these correlations could be tested further to ensure consistent
22 relationships over time and over regions. Because we are testing the hypothesis that electric
23 utilities' growth would converge toward the United States' estimated GDP growth, it seems
24 logical to test this across regions. Additionally, a key weakness in the data Staff analyzed is that
25 it does not extend past 1998. Staff deemed this necessary due to changes in the industry due to
26 restructuring. However, Staff did extend the termination year for the aggregate financial growth
27 figures for the companies in its *Central* region proxy group that continued to exist through 2010.
28 The correlations for the aggregate growth rates for the 5 remaining companies to that of the
29 utility industry's contribution to GDP growth and to overall GDP growth were approximately
30 97% and 91%, respectively.

31 Although there have been some strong correlations between aggregate electric utility
32 financial growth and utility and aggregate GDP growth rates, this has not translated into
33 equivalent per share financial growth for the electric utility industry. This is extremely important

1 to understand when estimating the cost of equity because this is what matters to investors and the
2 analysts that advise them. Historical experience has shown the per share growth was
3 approximately half of aggregate electric utility financial growth over the period analyzed
4 (see Schedule 20). Consequently, even if the Commission accepts the hypotheses that electric
5 utilities' growth may be dependent on aggregate GDP growth, historical financial evidence
6 proves this does not translate into the same growth on a per share basis. Historical evidence
7 indicates that these aggregate growth rates should be divided by two in order to consider the
8 dilution experienced by electric utility shareholders. The resulting perpetual growth rate would
9 be approximately 2% to 2.5%, which is lower than that which Staff used in its cost of equity
10 estimate, but consistent with the perpetual growth rates used by equity analysts when valuing
11 electric utility stocks.

12 Staff's research regarding the relation of GDP growth to that of utility industry growth
13 caused it to discover several journal articles that addressed GDP growth as it relates to EPS and
14 DPS growth of the S&P 500. In past rate cases, Staff has provided academic and logical support
15 that suggests that long-term nominal GDP growth may make sense as a proxy for perpetual
16 growth for a broader index, such as the S&P 500. However, this assumption may even be too
17 aggressive for purposes of estimating returns for the S&P 500.

18 William J. Bernstein and Robert D. Arnott published an article, "Earnings Growth: The
19 Two Percent Dilution," in the September/October 2003 edition of the *Financial Analysts*
20 *Journal*. This article reviewed some of the key drivers behind the bull market in the 1990s.
21 One such driver was an apparent belief that earnings could grow faster than the macroeconomy.
22 The authors contend that earnings must actually grow slower than that of the economy because
23 growth of existing enterprises contribute only partly to GDP growth; the role of entrepreneurial
24 capitalism, the creation of new enterprises, is a key driver of GDP growth, yet it does not
25 contribute to earnings and dividend growth of existing enterprises. The other main factor the
26 authors attributed to actual realized growth being less than that of aggregate GDP growth is that
27 new equity issuances almost always exceed stock buybacks by an average of 2% or more a year.

28 A key observation made by the authors that lends support for the notion that at least
29 aggregate corporate earnings may be able to grow at the same rate as GDP growth is that for the
30 period 1929 through 2000, trend growth for corporate profits and nominal GDP was
31 nearly identical. However, as the authors state, the ability of earnings and dividends to grow at

1 this same rate is only possible if no new enterprises are created and no new shares in existing
2 enterprises are issued. The authors illustrate that these two factors caused the growth in DPS
3 over the period 1900-2000 to be 2.7% lower than real GDP growth in the United States and
4 2.3% lower than real GDP for relatively stable countries throughout the world. Consequently,
5 empirical evidence shows that per share growth will be less than GDP growth even for the
6 broader markets. The findings from the Bernstein and Arnott article were largely confirmed in
7 another subsequent article, "Economic Growth and Equity Investing," by Bradford Cornell,
8 published in the January/February 2010 edition of the *Financial Analysts Journal*. Cornell
9 studied United States stock market data for the period 1926-2008. This information showed an
10 average rate of dilution from aggregate growth of approximately 2%. The author specifically
11 states: "Therefore, to estimate the growth rate of earnings to which current investors have a
12 claim, approximately 2% must be deducted from the growth rate of aggregate earnings."

13 Although not addressed in these articles, another reason why broader markets may not
14 grow at the same rate as U.S. GDP growth is because of the globalization of many companies
15 that are domiciled in the United States. According to Ned Davis Research, 52.6% of
16 pretax profits for companies in the S&P 500 came from outside the U.S.⁵² Consequently, the
17 profits of these global companies should also be dependent on the economic growth of the other
18 countries in which they operate.

19 The above-mentioned articles address the relation of GDP growth to that of broader stock
20 market growth expectations, not specifically to expected growth for utilities. In the August 2011
21 edition of *Public Utilities Fortnightly* ("PUF"), Steven Kihm addressed this issue more fully in
22 an article, "Rethinking ROE: Rational estimates lead to reasonable valuations."⁵³ Kihm
23 specifically addresses the recent common practice in utility rate cases of estimating the cost of
24 equity using the DCF and assuming that utility share prices can grow in perpetuity at the same
25 rate of nominal GDP. Kihm specifically stated the following in regard to the interaction of GDP
26 growth, DPS growth of the S&P 500, and DPS growth for the Moody's Electric Utility stock
27 index:

⁵² "A Smarter Way to Invest Globally? Maybe it's time for world-stock funds, rather than ones that focus separately on the U.S. and Overseas," Javier Espinoza, *The Wall Street Journal*, C5 and C8, June 4, 2012.

⁵³ "Rethinking ROE: Rational estimates lead to reasonable valuations," Steven Kihm, *Public Utilities Fortnightly*, August 2011, pp. 16-21.

1 In the last half of the 20th century, nominal GDP grew about 8 percent per
2 year. Dividends per share for the S&P 500 Index grew at only 6 percent
3 per year. Dividends per share for Moody's Electric Utility stock index
4 grew even more slowly at less than 4 percent per year. This suggests that
5 utilities can be expected to grow not at the GDP growth rate, but at about
6 half that rate on an annual basis.

7 Although Staff has drawn similar conclusions when analyzing long-term utility per share
8 growth as compared to GDP growth, Staff notes that Kihm identified the same 2% dilution in
9 S&P 500 DPS growth as discussed in the aforementioned financial literature. Staff verified this
10 observation by analyzing data provided in the *Economic Report of the President (2012)*, which
11 provides earning and dividend information for the S&P 500 from 1947 through 2011.
12 Schedule 21 clearly shows that actual realized EPS and DPS growth is less than that of nominal
13 GDP. Again, considering the fact that, on average, companies in the S&P 500 retain far more
14 earnings to pursue growth than utilities, no rational investor would expect utilities to grow in the
15 long-term at a rate close to that of nominal GDP.

16 Kihm discusses one of the often-used explanations as to why GDP should be used as a
17 proxy for long-term utility growth -- namely, that if utilities don't keep pace with economic
18 growth, they will become a shrinking segment of the economy. Staff's analysis of the BEA data
19 actually proves that this is in fact what has happened over the last 60 years. Over approximately
20 the last 20 years, utilities' *total value added* as a percentage of GDP growth has been declining.
21 Although it is hard to fathom that utilities will become obsolete, assuming utilities do not need to
22 expand to meet additional load growth, it is logical to assume that utilities should not grow much
23 faster than the rate of inflation in the long-term.

24 Kihm worked for more than 20 years as a member of the staff of the Public Service
25 Commission of Wisconsin ("Wisconsin Commission"). He developed the staff's two-stage DCF
26 model, which is still used by Wisconsin Commission staff. The Wisconsin Commission staff's
27 DCF model uses the inflation rate for the perpetual growth rate for utilities.

28 In the PUF article, Kihm also discusses the impact of dilution on expected growth rates
29 for utilities by comparing Southern Company's aggregate dividend growth rate and
30 Southern Company per share dividend growth rate to that of GDP growth for the period 1995 to
31 2010. Southern Company's annual compound growth rate for *aggregate* dividends was 4.2%,
32 while the annual compound growth rate for nominal GDP was 4.6% for this same period.
33 However, after taking into consideration the additional common equity Southern Company

1 issued over this period, the annual dividend compound growth rate was only 2.6% on a per share
2 basis. Clearly this empirical evidence disproves the assumption that utilities could grow
3 anywhere near the rate of GDP growth over the long-term.

4 A simple example using the earnings retention method of estimating sustainable growth
5 rates illustrates the fallacy of assuming that utility per share growth rates can approach the level
6 of aggregate GDP growth. The S&P 500 has historically earned ROEs in the 10% to 15% range
7 with an average close to 12.5%.⁵⁴ For purposes of this example, we will assume that the
8 S&P 500 will earn a 12.5% ROE in the long-run. Assuming the S&P 500 dividend payout ratio
9 remains near the average of approximately 40% for the past decade, then this translates into
10 60% of earnings retained for reinvestment. At an expected 12.5% ROE (mid-point of the 10% to
11 15% range), this translates into a potential growth rate of 7.5% for the S&P 500. Now, assuming
12 electric utilities should be allowed to earn an ROE similar to that of the S&P 500, which would
13 be too high in Staff's opinion, since electric utilities typically maintain a dividend payout ratio of
14 approximately 65%, this allows for a potential growth rate of 4.375%. Consequently, simple
15 mathematics dictates that because electric utilities have higher payout ratios than the S&P 500,
16 even if they earn a similar ROE, their per share growth would have to be lower than the
17 S&P 500. Considering that the allowed ROEs have been in the 10% to 10.25% range, assuming
18 electric utilities continue to pay out 65% of their earnings in dividends, this would translate into
19 a growth rate of approximately 3.5%.

20 It is worth emphasizing that the articles Staff has reviewed explore the relationship of
21 GDP growth to EPS and DPS for the broader markets, such as the S&P 500. This is consistent
22 with most mainstream financial literature that suggests expected nominal GDP growth can be
23 used as a proxy for perpetual growth for a broad index. However, Staff is not aware of any such
24 literature that suggests this is appropriate for a mature, low-growth sector such as that of utilities.
25 In fact, Staff has provided evidence in past cases that investment analysts do not make this
26 assumption when estimating a fair price to pay for utility stocks.

27 Kihm also provides an example of why current utility stock prices seem logical when
28 using a more reasonable cost of equity estimate. In Kihm's example, he uses an 8% cost of
29 equity to arrive at a price estimate of \$50.62 for Consolidated Edison, which was within 4% of

⁵⁴ Timothy Vick, "Picking Stocks The Buffett Way: Understanding Return on Equity," American Association of Individual Investors, April 2001; Frank K. Reilly, "The Impact of Inflation on ROE, Growth and Stock Prices," Financial Services Review, 1997.

1 the stock price at the time (June 2011). Kihm's example can be taken one step further by
2 performing a DCF valuation estimate using the same cost of equity and the assumption that
3 utility dividends per share can grow at the same rate as GDP in the long-term. Consolidated
4 Edison's annual dividend in 2011 was \$2.40. If one assumes that this dividend can grow in
5 perpetuity at a compound annual rate of 5% and the cost of equity is the same 8% used by Kihm,
6 then this would translate into an intrinsic value of \$84, 66% higher than its current trading price.
7 However, if one assumes a much more reasonable dividend growth rate of approximately 3%
8 with the same cost of equity, then the intrinsic value of the stock would be \$49.44, which is close
9 to Kihm's estimate.

10 **

11
12
13
14 ⁵⁵ It is this clear-cut evidence that should be considered by the Commission when
15 determining the reasonableness of certain projected growth rates for dividends in the long-run.

16 **vi. Preference for GDP Growth**

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

22 Projected GDP growth is available from a variety of sources, such as the Congressional
23 Budget Office ("CBO"), the Federal Reserve, the EIA, and Blue Chip Economic Forecasts. Staff
24 will use the CBO, EIA, The Survey of Professional Forecasters published by the Philadelphia
25 Federal Reserve, The Federal Open Market Committee ("FOMC"), and The Livingston Survey
26 for purposes of long-term projected GDP growth. The CBO projects an annual compound
27 growth rate in nominal GDP of approximately 4.90% through 2022; EIA projects an annual
28 compound growth rate of 4.4% for the period 2010 through 2035; The Survey of Professional
29 Forecasters projects a 10-year annual compound growth rate in real GDP of 2.64%;

⁵⁵ KCPL's response to Staff Data Request No. 0209.

1 The Livingston Survey projects an average annual compound growth rate of 2.7% over the next
2 ten years and the FOMC projects a central tendency long-term real GDP growth of 2.3% to
3 2.6%. In each case in which the sources do not project a nominal GDP growth rate, Staff
4 recommends adding a GDP price deflator of 2.0%, which is the CBO's prediction of long-term
5 inflation and also the inflation rate which is targeted by the Federal Reserve. Based on these
6 projections, the long-term nominal GDP growth rate is expected to be in the range of 4.3% to
7 4.9%. If the Commission chooses to use a GDP growth rate to estimate the cost of equity, Staff
8 recommends the Commission use the lower end of the range (4.3%) because of the amount of
9 evidence that shows that rational investors would not expect utility per share figures to grow at
10 the same rate as GDP. When using a 4.3% GDP growth rate in Staff's multi-stage DCF results
11 in a cost of equity estimate of approximately 8.85%.

12 **G. Tests of Reasonableness**

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

15 **1. The CAPM**

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

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

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

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 2010. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending May 30, 2012; that figure was 3.13%. For Beta, Staff used Value Line’s betas for the comparable companies (see Schedule 22). The average beta (β) for the proxy group was 0.69. For the market risk premium (Rm – Rf), Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.⁵⁶ The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2011, which was 5.70%. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2011, which was 4.10%.

Staff’s CAPM is presented on Schedule 22. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.06% and 5.96%, respectively. While the cost of equity indication using the geometric average risk premium is more than likely below equity discount rates used to value utility stocks, Staff believes the 7.06% cost of equity is quite probable considering the current low bond yield environment. It is generally recognized that the risk premium over Treasury yields is higher than historical averages due to the Fed’s efforts to keep Treasury yields quite low. However, this increases the opportunity costs of not investing in utility bonds and stocks, which puts pressure on the prices of these alternative, low-risk investments.

⁵⁶ From Ibbotson Associates, Inc.’s *Stocks, Bonds, Bills, and Inflation: 2012 Yearbook*.

1 10.05% for the first six months of 2012. The average authorized cost of common equity for
2 electric utility companies for 2011 was 10.22% based on 41 decisions (first quarter – 10.32%
3 based on thirteen decisions; second quarter – 10.12% based on ten decisions; third
4 quarter – 10.00% based on seven decisions; fourth quarter – 10.34% based on eleven decisions).

5 The average authorized ROR for electric utilities for the first six months of 2012 was
6 7.89% based on 23 decisions (first quarter – 8.00% based on 11 decisions; second
7 quarter – 7.78% based on 12 decisions). The average authorized ROR for electric utilities in
8 2011 was 7.95% based on 41 decisions (first quarter – 8.12% based on 13 decisions;
9 second quarter – 8.01% based on 10 decisions; third quarter – 8.09% based on 7 decisions;
10 fourth quarter – 7.61% based on 11 decisions).

11 While Staff understands the Commission's desire to review other commissions'
12 authorized ROE's due to concerns about Missouri-jurisdictional utilities having to compete with
13 other utilities for capital, Staff would like to briefly explain why an allowed ROE is not
14 indicative of a required ROE and the ability to attract capital. The primary consideration for
15 attraction of capital is whether the current price of a given stock will result in the investor
16 earning above, below or equivalent to their required return. For example, the allowed ROEs for
17 many of Southern Companies' utility subsidiaries are typically much higher than the rest of the
18 utilities in the country. However, this does not translate into higher realized returns for investors
19 in Southern Company because the price of Southern Company's stock already reflects these high
20 allowed ROEs. If this Commission were to award an ROE similar to those allowed for
21 Southern Company's subsidiaries and hold all other ratemaking treatments constant, then current
22 investors in the Missouri utility would achieve a return that was higher than their required return.
23 However, after the increase in the Missouri utility's stock price, the investor and subsequent
24 prospective investors would revert back to earning their required return. The opposite holds true
25 if the Commission were to authorize an ROE below what is expected from the Commission.
26 Consequently, setting allowed ROEs based on those allowed or earned for other companies may
27 temporarily cause upward or downward pressure on the stock, but once this price correction
28 occurs, the stock should experience "normal" capital attraction

29 c. Equity Analysts

30 Past Commission decisions have expressed the view that the cost of equity used by equity
31 analysts is not relevant to determining a reasonable cost of equity estimate in utility ratemaking

1 proceedings. Although Staff respects the Commission's decisions based on the evidence the
2 Commission reviewed in past rate cases, Staff believes it can provide further analysis and
3 explanation that supports the relevance of these cost of equity estimates to the cost of capital
4 determined in a utility rate proceeding.

5 First, it is important to consider the inherent contradiction caused by using equity
6 analysts' 5-year EPS growth rate forecasts as the constant growth rate of dividends in the
7 single-stage DCF, but ignoring the rest of the analysis performed by the equity analysts. It is
8 naïve to assume that investors would simply take values from the internet without researching
9 the supporting analysis when making investment decisions. While this assumption may allow
10 for expediency in estimating the cost of equity, investors do not make investment decisions with
11 expediency as a priority. Staff has reviewed numerous equity research reports and it has NEVER
12 seen an analyst estimate a fair price for a utility stock by making this naïve assumption. If the
13 equity analysts that provide professional investment advice based on in-depth analysis do not
14 utilize their own growth rates in this manner, then it is completely illogical to make this
15 assumption for purposes of estimating the cost of equity. If the cost of equity is not considered a
16 fair return in terms of the *Hope* and *Bluefield* cases, then the time and effort devoted to
17 rate-of-return testimony would be better spent on determining an appropriate margin over the
18 cost of equity that would be fair in setting the allowed ROE.

19 Rate-of-return witnesses often cite various academic studies to support their position that
20 investors naïvely assume that dividends can grow in perpetuity at the same rate as equity
21 analysts' estimates of the 5-year annually compounded EPS growth rate. Although Staff
22 believes the fact that the very equity analysts that provide these forecasts do not make this same
23 assumption when valuing utility stocks disproves this conclusion, it is important to understand
24 the true conclusion of some of these studies. One of the studies often cited to support the use of
25 equity analysts' 5-year EPS growth rate forecasts in the DCF is that of Burton G. Malkiel and
26 John G. Cragg, "Expectations and the Structure of Share Prices." The conclusion of this
27 academic study was that equity analysts' expectations had a greater influence on stock prices
28 compared to simple extrapolations of historical financial data. Staff believes this conclusion is
29 logical considering the vast amounts of resources dedicated to the discipline of securities
30 analysis. However, Staff is not sure how subsequent studies concluded that the results of this
31 study somehow translated into a proof that investors use 5-year EPS forecasts as a constant

1 growth rate in the single-stage DCF methodology. In fact, the Cragg and Malkiel did not even
2 use the DCF valuation model when testing their hypothesis regarding the influence of analysts'
3 projections on stock prices. It is more plausible to conclude that, because investors rely on
4 equity analysts' expectations, they rely on their investment recommendations (e.g. buy, sell or
5 hold). Equity analysts' investment recommendations are based on their assessment of the
6 intrinsic value of a given stock. Analysts' methodologies for estimating a fair price varies, but
7 most at least assess the current price-to-forward earnings ratios both on a consensus basis and on
8 the analysts' own estimates. If the analyst believes the company can grow its earnings faster
9 than the consensus and/or the company deserves a higher p/e ratio than the consensus, then the
10 analyst will expect a higher return than the consensus. In Staff's experience, this is the primary
11 purpose for providing both absolute EPS forecasts and EPS growth rate forecasts. It allows
12 investors to estimate a potential justified p/e multiple.

13 Cragg and Malkiel specifically indicated the following in their study:

14 We would not argue that these estimates necessarily give an accurate
15 picture of general market expectations. It would, however, seem
16 reasonable to suggest that they are representative of opinions of some of
17 the largest professional investment institutions and that they may not be
18 wholly unrepresentative of more general expectations. **Since investors**
19 **consult professional investment institutions in forming their own**
20 **expectations, individuals' expectations may be strongly influenced—**
21 **and so reflect—those of their advisers.** That several of our participating
22 firms find it worthwhile to publish these projections and provide them to
23 their customers provides prima facie evidence that a certain segment of the
24 market places some reliance on such information in forming its own
25 expectations. Also, insofar as other security analysts and investors follow
26 the same sorts of procedures as those used by our sample analysts in
27 forming expectations, general investors' expectations would resemble
28 those of the analysts. Consequently, these predictions may well serve as
29 acceptable proxies for general expectations and surely seem worthy of
30 detailed analysis. (emphasis added)

31 In past rate cases the Commission has dismissed evidence Staff presented regarding
32 assumptions investment analysts use to estimate a fair price to pay for utility stocks. Considering
33 the above information, in which the foundation for the study concludes that investors rely and
34 depend on their investment advisors, and therefore, stock prices reflect these expectations, it
35 would seem that the cost of equity assumptions used by these investment analysts are indeed
36 reflected in share prices. To assume that investors utilize the information provided by equity

1 analysts in a way that is wholly inconsistent with how the very analysts that provide them use
2 them, is not supported by any evidence.

3 Equity analysts often use the dividend discount model (“DDM”) to estimate a fair price to
4 pay for the stock. The DDM is synonymous with the DCF in utility ratemaking settings. The
5 DCF in utility ratemaking is simply solving for the required return/cost of equity variable.
6 In valuation, the goal is to solve for the fair price of the stock. Consequently, if equity analysts
7 are of value to their clients, then the stock prices will reflect their estimates of future dividends
8 and the required return on these dividends. Consequently, if one accepts the studies that security
9 analysts’ expectations influence investors, which is the conclusion made by Malkiel and Cragg,
10 then this means that stock prices reflect the cost of equity used by these very same analysts.
11 Staff’s experience has been that these equity discount rates are usually much lower than cost of
12 equity estimates provided by ROR witnesses in utility rate cases. Staff has provided many
13 examples in the last several rate cases that indicate equity analysts use equity discount rates in
14 the 7% to 9% range when valuing utility stocks. However, this does not mean that these equity
15 analysts expect commissions to allow an ROE equivalent to the market-implied cost of equity. If
16 allowed ROEs were set equal to the cost of equity, this would cause downward pressure on the
17 stock price of a company whose earnings rely primarily on the regulated utility operations. This
18 is the case because utility stock prices currently reflect investors’ expectations of regulators
19 continuing to allow returns of close to 10%.

20 Considering the fact that the Cragg and Malkiel study is the foundation for other studies
21 that are cited to support the use of 5-year EPS forecasts in the constant growth DCF, it is
22 important to understand how at least one of the authors has estimated required returns on stocks
23 in his past studies and how he estimates required returns currently. In his May 1979 study,
24 “The Capital Formation Problem in the United States,” Malkiel estimated the required returns on
25 the Dow Jones Industrial Average by using Value Line growth rates for the first five years. This
26 growth rate was then reduced over time to that of the expected real growth rate of the economy,
27 which was 3.6% at the time.⁵⁹

⁵⁹ The use of a real GDP growth rate for perpetual growth is consistent with Goldman Sachs’ valuation approach discussed in the last Ameren Missouri rate case, Case No. ER-2011-0028. While the Commission interpreted this to mean that inflation needed to be added to the real GDP growth rate to make the analysis correct, Malkiel made it clear that he purposely chose real GDP as a perpetual growth rate, but also indicated an argument could be made to use nominal GDP.

1 In a recent January 5, 2012, editorial in the *Wall Street Journal*, "Where to Put Your
2 Money in 2012," Burton G. Malkiel provided his opinion on the long-run return expectations for
3 U.S. equities. Malkiel simplified his approach by simply indicating that earnings and dividends
4 in the market have grown at an approximate 5% rate over the long run. He simply added this
5 long-run growth rate to the current approximate 2% dividend yield on the U.S. stock market to
6 arrive at a long-run return estimate of 7% for the U.S. stock market, which is very close to the
7 6.80% projected return on the S&P 500 estimated by professional forecasters in the
8 First Quarter 2012 *Survey of Professional Forecasters*. If Malkiel believed investors projected
9 returns based on 5-year EPS forecasts on the U.S. stock market, then he would have projected a
10 long-run return of approximately 12.3% (2% dividend yield plus 10.3% 5-year EPS growth
11 forecasts for the S&P 500). He did not. While Malkiel and Cragg's studies certainly concluded
12 that security analysts' estimates have an impact on share prices, they did *not* conclude that
13 investors would assume security analysts' 5-year EPS growth rate forecasts are a proxy for
14 perpetual growth.

15 The focus on earnings growth rates is understandable considering that most security
16 analysts' stock predictions are based on a multiple of p/e ratios, but security analysts provide this
17 information to evaluate potential p/e ratios as they compare to consensus p/e ratios. The ability
18 of the analyst to accurately project future earnings and justified p/e ratios will determine whether
19 that analyst is successful. Consequently, the focus on analysts' EPS projections is
20 understandable in this context.

21 **H. Cost of Equity Compared to Returns on Equity**

22 It would likely be of interest to the Commission that the aforementioned Kihm article is
23 not necessarily advocating that the allowed ROE be set based on a utility company's cost of
24 equity. While it is quite clear that Kihm believes the cost of equity for utilities is in the
25 7% to 8% range, he does not advocate that commissions set the allowed ROE at this lower level.
26 Kihm is just pointing out that commissions "might be doing the right thing, but for the wrong
27 reason." Kihm is simply trying to emphasize that allowed ROEs should not be assumed to be the
28 cost of equity for purposes of making investment decisions or for purposes of valuing utility
29 assets or securities. Staff has performed extensive discovery in past rate cases that provide
30 assurance that utility companies are not confusing the allowed ROE with the cost of equity.

1 In fact, Staff discovered the valuation analyses GPE and Aquila performed on the current
2 properties known as GMO, used a cost of equity much lower than the allowed ROE.⁶⁰

3 It is also quite clear from Staff's analysis of equity analysts' reports that analysts do not
4 expect commissions to set the authorized ROE equal to the cost of common equity. Most equity
5 analysts use a cost of equity in the 7% to 8% range, yet when projecting cash flows generated by
6 the utilities through ratemaking, they assume companies will be authorized an ROE of close
7 to 10%. While the Staff does not believe the Commission should allow investors' expectations
8 of the authorized ROE determine what is authorized in a rate case, Staff does recognize that
9 investors have become accustomed to some margin over the cost of equity being allowed in
10 rates. In fact, some would argue that because book ROEs of the S&P 500 (10% to 15% on
11 average) tend to be higher than the market cost of equity, this may justify the decision to allow
12 an ROE higher than the cost of equity. If the Commission accepts this premise, then the
13 issue before it would be what margin is fair and reasonable for purposes of complying with
14 *Hope and Bluefield*. This is a matter that could be explored further if the Commission accepts
15 the notion that the cost of equity is lower than that which it chooses to authorize.

16 I. Conclusion

17 A just and reasonable rate is one that is fair to the investors and fair to the ratepayers.
18 Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to
19 the shareholders. Fairness to the shareholders means rates that will produce revenues, on an
20 annual basis, sufficient to cover KCPL's prudent cost of service, which includes its cost of
21 capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted
22 average cost of capital for KCPL in the range of 7.14% to 7.66% (*see* Schedule 23). This rate
23 was calculated by applying an embedded cost of long-term debt of ** ____ ** and a cost of
24 common equity range of 8.00% to 9.00% to a capital structure consisting of ** ____ **
25 common equity, ** ____ ** long-term debt, and ** ____ ** preferred stock. Because there
26 appears to be some concern in setting an allowed return on equity based on the cost of equity,
27 Staff recommends the Commission set the allowed ROE at 9.00% in this case. Although this is
28 well-above what Staff believes the true cost of equity to be in the current capital market
29 environment, this allowed ROE would balance the concern about the impact a lower allowed

⁶⁰ Staff Cost of Service Report in Case No. ER-2009-0089, p. 39-42.

1 ROE would have on investors' view of Missouri's regulatory environment, while still passing
2 along the benefit of lower capital costs to ratepayers.

3 *Staff Expert/Witness: David Murray*

4 **VII. Rate Base**

5 **A. Plant-in-Service and Accumulated Depreciation Reserve**

6 Staff recommends plant-in-service ("plant") and accumulated depreciation reserve
7 ("reserve") balances be based on actual booked amounts as of the Update Period,
8 March 31, 2012, except as discussed in the Depreciation section of this Report.⁶¹ This includes
9 plant additions that have occurred since the test year ending September 30, 2011, and the related
10 depreciation reserve balances. At the time of the True-up, adjustments to the plant balances Staff
11 used for its direct filing will be updated to include amounts for plant additions that have become
12 fully operational and used for service during the period of March 31, 2012, through August 31,
13 2012, the True-up cut-off date. Staff will also make a true-up adjustment to update for
14 depreciation reserve balances related to those additions. Plant must be "fully operational and
15 used for service," before it is appropriate to reflect that plant and its associated reserve in rates.

16 The plant for KCPL for the period ending March 31, 2012, is identified on the Plant
17 Accounting, Schedule 3, and the accumulated depreciation reserve as of that date is identified in
18 the Depreciation Reserve, Accounting Schedule 6.

19 During the analysis of KCPL's plant reserve balances, Staff found KCPL had made
20 adjustments to the reserve account balances for retirement work in progress ("RWIP").⁶²
21 KCPL removed the retired plant and related depreciation reserve from its plant and reserve

⁶¹ Staff recommends the Commission order KCPL to make adjustments in general plant reserves accounts of a total of \$6,483,406 to address an under recovery of plant, (deficiency in depreciation reserves). Staff is recommending two adjustments:

- An adjustment, (increase of reserves) of \$4,844,004 related to early retirements of plant and equipment related to KCPL and former Aquila facilities consolidations and relocations attributable to the Aquila acquisition.
- A transfer of \$1,639,402 from transmission plant reserves (that are collectively over accumulated in excess of \$30,000,000) to distribute within general plant accounts 390, 391, 393, 394, 395, 397, and 398.

Staff recommends the transfer of accumulated reserves between accounts within the general plant accounts, such that in conjunction with the \$6,483,406 from recommendation 3 above, result in a rebalancing of reserves in the general plant accounts to remove over and under recovery in accounts 390, 391, 393, 394, 395, 397, and 398.

⁶² RWIP is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage.

1 account balances as of the retirement dates. However, as of March 31, 2012, KCPL had not
 2 removed the related reserve for cost of removal and salvage. As a result, KCPL's books
 3 overstate the reserve for this retired plant; and, therefore, Staff made an adjustment to remove the
 4 plant that was no longer being used for service from the reserve balances. Staff included a line
 5 item in the Accumulated Depreciation schedule, identifying the RWIP associated with
 6 Production, Transmission, Distribution, and General Plant. Staff also made an adjustment to
 7 include amortization of intangible plant for assets that KCPL has paid for the right to use or
 8 operate, but that KCPL does not legally own. Accumulated amortization is recorded for these
 9 intangible assets on an individual basis, and amortization ceases when the book value reaches
 10 zero. The amortization rate was set for each account using the depreciation rate of assets with the
 11 same classification. Adjustments E-243.1 and E-248.1 reflect the amortization of Intangible
 12 Plant for KCPL

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

Load	Unit	Year Completed	Estimated 2011 MW Capacity	Primary Fuel	
Base Load	Iatan No. 2	2010	465(a)	Coal	
	Wolf Creek	1985	560(a)	Nuclear	
	Iatan No. 1	1980	494(a)	Coal	
	LaCygne No. 2	1977	341(a)	Coal	
	LaCygne No. 1	1973	368(a)	Coal	
	Hawthorn No. 5(b)	1969	563	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	310	Natural Gas
Osawatomie		2003	75	Natural Gas	
Hawthorn No. 9		2000	130	Natural Gas	
Hawthorn No. 8		2000	77	Natural Gas	
Hawthorn No. 7		2000	77	Natural Gas	
Hawthorn No. 6		1997	136	Natural Gas	
Northeast Black Start Unit		1985	2	Oil	
Northeast Nos. 17-18		1977	110	Oil	
Northeast Nos. 13-14		1976	105	Oil	
Northeast Nos. 15-16		1975	96	Oil	
Northeast Nos. 11-12		1972	98	Oil	
Wind		Spearville 2 Wind Energy Facility (c)	2010	4	Wind
		Spearville WindEnergy Facility (d)	2006	8	Wind
Total KCP&L			4529		

Load	Unit	Year Completed	Estimated 2011 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	2010	153(a)	Coal
	Iatan No. 1	1980	127(a)	Coal
	Jeffrey energy Center Nos. 1, 2 and 3	1978, 1980, 1983	173(a)	Coal
	Sibley Nos.1, 2 and 3	1960, 1962, 1969	466	Coal
	Lake Road Nos. 2 and 4	1957, 1967	125	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	2005	314	Natural Gas
	Crossroads Energy Center	2002	297	Natural Gas
	Ralph Green No. 3	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	1975-1979	255	Natural Gas/Oil
	Lake Road No. 5	1974	63	Natural Gas/Oil
	Lake Road Nos. 1 and 3	1951, 1962	33	Natural Gas/Oil
	Lake Road Nos. 6 and 7	1989, 1990	41	Oil
	Nevada	1974	21	Oil
	Total GMO			2139
Total Great Plains Energy			6668	

- a. Share of a jointly owned unit.
- b. The Hawthorn Generating Station returned to commercial operation in 2001 with a new boiler, air quality control equipment and an uprated turbine following a 1999 explosion.
- c. The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 4 MW pursuant to SPP reliability standards.
- d. The 100.5 MW Spearville Wind Energy Facility's accredited capacity is 8 MW pursuant to SPP reliability standards.

Source: GREAT PLAINS ENERGY INC. 10-K. February 25, 2011

Staff Expert/Witness: Patricia Gaskins

1. Iatan Common Plant Transactions

On March 9, 2012, in Case No. EO-2011-0334, KCPL filed an Application for (1) approval of the transfer of existing common facilities located at the Iatan Generating Station to the Kansas Electric Power Cooperative, Inc. (KEPCo) and the Missouri Joint Municipal Electric Utility Commission (MJMEUC); (2) approval of the transfer of interests in permits to other owners of the new Iatan Unit 2 electric generating facility (Unit 2); and (3) approval, if deemed necessary, for the sale of an interest in utility materials and supplies inventory to KEPCo and MJMEUC.

1 Also on March 9, 2012, in Case No. EO-2012-0015, KCPL, GMO, and The Empire
2 District Electric Company (Empire) filed a Joint Application for the approval of (1) Iatan Unit 1
3 owners (KCPL, GMO, and Empire) to lease, and grant easements over, portions of the Initial
4 Iatan Station Site to the Unit 2 owners (KCPL, GMO, MJMEUC, and KEPCo) covering Unit 2
5 and the Common Facilities, and (2) the leasing of the Nower Property (a tract of land adjacent to
6 the Initial Iatan Station Site) by KCPL to the other Unit 1 and Unit 2 owners for the landfill
7 portion of the Common Facilities.

8 In its June 20, 2012 Order Granting Application in Case No. EO-2012-0015, the
9 Commission approved the Joint Application but noted that its Order Granting Application does
10 not determine any matter related to accounting or ratemaking in Case No. ER-2012-0174, Case
11 No. ER-2012-0175, and the next general rate action of The Empire District Electric Company.
12 The Commission also issued an Order Granting Application in Case No. EO-2011-0334 on
13 June 20, 2012.

14 The Staff has had discussions with KCPL as to how to treat these transactions in the
15 current KCPL and GMO rate cases. Because the Commission's Orders approving these
16 transactions became effective only recently, KCPL has not proposed any specific ratemaking
17 methodology for these transactions as of the date of the Staff's direct filing. The Staff expects
18 that it will have ongoing discussions with KCPL once Staff is aware of how KCPL proposes to
19 treat these transactions in the rate cases, and will reflect the appropriate ratemaking treatment in
20 its true up revenue requirement proposal in this case.

21 *Staff Expert/Witness: Charles R. Hyneman*

22 **B. Material and Supplies**

23 Staff's recommended treatment of materials and supplies is to examine each account
24 individually in order to determine an appropriate level that most accurately reflects the ongoing
25 future expense of a particular account. Materials and supplies represent an investment in
26 inventory for items such as spare parts, electric cables, poles, meters, and other miscellaneous
27 items used in daily operations and maintenance activities by KCPL to maintain KCPL's
28 production facilities and electric system. Because the account balances varied greatly depending
29 on each individual account, Staff reviewed the balances for each account for materials and
30 supplies individually on a monthly basis to determine whether trends within an individual

1 account existed over time. Staff reviewed the monthly balances for materials and supplies
2 accounts from September 2010 to March 2012. If an upward or downward trend was detected,
3 then Staff used ending balance for that account. If there was no discernible trend, then a
4 13-month average was figured and determined to be the most appropriate measure of the ongoing
5 expense for that account. Staff examined the accounts individually and determined which
6 methodology, 13-month average or ending balance, was the most appropriate measure to
7 accurately predict the ongoing future of a particular account (Accounting Schedule 2).

8 *Staff Expert/Witness: Patricia Gaskins*

9 **C. Prepayments**

10 Staff's recommended treatment of prepayments is to examine each prepayment account
11 individually in order to determine an appropriate measure that most accurately predicts the
12 ongoing future expense of a particular prepayment account, and then to include the prepayments
13 in KCPL's rate base. Prepayments are the costs a company incurs and pays in advance. KCPL
14 buys property insurance to protect its assets, the costs of which are treated as a prepayment and
15 included in rate base. Prepayments are treated as an asset and are reflected in the utility's rate
16 base. Staff included amounts in its rate base for all prepayments that KCPL requires to provide
17 electric utility service to its customers. Staff examined all of KCPL's prepayment account
18 balances dating back to KCPL's previous rate case (ER-2010-0355) through March 31, 2012, on
19 a month-by-month basis. Based on this review, and the variability in the monthly account
20 balances, Staff determined the prepayment levels to be included in KCPL's rate base. These
21 amounts were determined by multiple methodologies, including: calculating an average based on
22 balances for the 13-months ending March 31, 2012. Staff used this approach on accounts where
23 there was no discernible upward or downward trend in the monthly balances. Staff also used the
24 most recent account balance (March 31, 2012) on accounts where a noticeable upward or
25 downward trend was present.

26 Staff did not include prepayments related to gross receipts taxes. While KCPL includes
27 gross receipts taxes as a prepayment, these costs are actually paid in arrears and as a result, Staff
28 excluded these taxes from prepayments. The cash flow impact on KCPL for gross receipts taxes
29 is reflected in Staff's Cash Working Capital calculation as shown on Accounting Schedule 8.
30 The Commission should base its awarded revenue requirement on Staff's recommended

1 appropriate measure of prepayments added to KCPL's rate base, indicated in Accounting
2 Schedule 2. Staff further recommends that prepayment expenses should not include
3 prepayments for gross receipts taxes.

4 *Staff Expert/Witness: Patricia Gaskins*

5 **D. Cash Working Capital**

6 Cash Working Capital ("CWC") is the amount of cash necessary for a utility to pay the
7 day-to-day expenses incurred to provide utility services to its customers. Cash inflows from
8 payments received by the Company and cash outflows for expenses paid by the Company are
9 analyzed using a lead/lag study. In KCPL's prior rate case, Case No ER-2010-0355, Staff
10 performed a partial study analyzing gross receipts taxes ("GRT") and injuries and
11 damages ("I&D") while relying on calculations made by KCPL and the Staff in previous cases
12 for all other lags. KCPL has adopted the GRT and I&D lags developed by Staff and is
13 essentially using the same expense lags used by Staff in the 2010 rate case. Staff has reviewed
14 the direct testimony of KCPL witness John P. Weisensee and Staff's recommended revenue lag
15 agrees with the revenue lags as outlined on pages 23 and 24 of his testimony except that Staff did
16 not adjust the 15.21 days service period lag "to 15.25 days to reflect the 2012 leap year"
17 (Weisensee Direct, page 23, line 22).

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

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

1 electric services before the utility paid the expenses that the utility incurred to provide
2 those services.

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

8 KCPL sells all of its account receivables to Kansas City Power & Light Receivables
9 Company ("KCREC"). This program increases immediate cash flow and provides access to
10 funds through lines of credit. As a result of the immediate cash flow and the need to no longer
11 attempt to collect on their account receivables, KCPL reduces the collection lag associated with
12 cash working capital. Ratepayers benefit from the program since cash was generated by the sale
13 of the receivables instead of from the ratepayers. More detailed information about KCPL's
14 account receivable sales program can be found under the heading KCPL Accounts Receivable
15 Bank Fees later in this report.

16 *Staff Expert/Witness: V. William Harris*

17 **E. Fuel Inventories**

18 **1. Coal Inventory**

19 The amount Staff included in KCPL's rate base for coal inventory is based on the results
20 obtained from Staff's production cost model (fuel model). Staff used its fuel model to determine
21 the appropriate mix of generation unit and purchased power utilization to match the normalized
22 native load for KCPL. In doing so, Staff obtained from the fuel model an annual amount of tons
23 of coal burned by each coal-fired generation unit during the normalized updated test year. Staff
24 divided the annual tons of coal burned from the fuel model by 365 days to calculate an average
25 daily burn by unit. Staff then multiplied this average daily burn by KCPL's recommended
26 number of burn days of coal inventory for each generation unit and added an estimated level of
27 basemat coal. Basemat coal is the bottom portion of the coal pile that is not usable as fuel due to
28 contamination by soil, clay, and other contaminants. Staff then multiplied the resulting
29 normalized level of inventory for each unit by the delivered cost per ton of coal for use at that
30 unit. The resulting annual coal costs for each unit were then aggregated. The aggregated amount

1 was multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory
2 amount shown in Rate Base – Schedule 2.

3 In addition to coal inventories for native load, Staff included an amount of coal inventory
4 for interchange sales, a portion of which are referred to as Off-System Sales. Staff obtained the
5 amount of interchange sales from KCPL's coal-fired generating stations for the 12-months
6 ending March 2012. Staff converted this amount of sales to an equivalent annual burn of coal
7 and included it in its calculation for coal inventories. Staff is continuing to evaluate the
8 appropriateness of including these specific coal inventories in rate base in the cost of service.

9 Staff used current delivered prices to determine the rate base inventory value for the
10 estimate of basemat coal inventory. Basemat is not considered readily available for use and
11 amount of this contaminated coal acts as a buffer between the ground and readily burnable coal.
12 Staff is continuing to evaluate the appropriateness of using a current delivered price for this
13 inventory as opposed to a historical average price.

14 *Staff Expert/Witness: Keith Majors*

15 **2. Nuclear Inventory**

16 To determine the amount to include in rate base for KCPL's nuclear fuel inventory, Staff
17 used an 18-month average of the value of nuclear fuel that was contained in the fuel core of the
18 Wolf Creek nuclear generating unit. Since the Wolf Creek unit is refueled every 18 months, this
19 18-month time period reflects the average nuclear fuel inventory value during a complete nuclear
20 fuel usage cycle at Wolf Creek. This approach is consistent with the method used by KCPL in
21 the presentation of its direct case.

22 *Staff Expert/Witness: Keith Majors*

23 **3. Oil and Fuel Additive Inventories**

24 Staff used 13-month averages to determine the inventory levels for oil, lime, limestone,
25 ammonia, and powder activated carbon inventories as of March 31, 2012. A 13-month average
26 inventory reflects the Company's actual experience for the entire 12-month test year period by
27 including a beginning inventory and an ending inventory. For example, if the test year were a
28 calendar year it would begin with January 1 and end with December 31. A 13-month average
29 reflects the entire year by using the December 31 (January 1) beginning balance and including

1 each subsequent month-ending balance through the end of the year (December 31). Twelve
2 month-ending balances from January 31 through December 31 do not accurately reflect the
3 Company's actual experience because they ignore the impact of the period from January 1
4 through January 30. When inventory levels fluctuate from month to month, as they do with fuel
5 stocks, a 13-month average is used to smooth out those levels. Staff's inventory levels for coal,
6 nuclear, oil, limestone, and ammonia are shown in Rate Base – Schedule 2. Staff's approach is
7 consistent with the method used by KCPL in the presentation of its direct case.

8 *Staff Expert/Witness: Keith Majors*

9 **F. Customer Deposits**

10 Staff's recommended treatment of customer deposits is to deduct the most current
11 customer deposit balance, as reflected in the Missouri jurisdictional total, from KCPL's rate
12 base. Customer deposits are the funds required to be provided by certain customers taking
13 electrical service from KCPL. These funds are deducted from KCPL's rate base because these
14 funds are cost-free funds received by KCPL. The amount reflected for customer deposits on
15 Accounting Schedule 2, Rate Base, is the most current customer deposit balance as of
16 March 31, 2012. The balance reflected on the Rate Base Schedule is the Missouri jurisdictional
17 total for customer deposits. The March 31, 2012, balance was used because the account balance
18 exhibits a consistent trend. In addition to the amount deducted from rate base for customer
19 deposits, an amount for interest on customer deposits has been included as an adjustment to the
20 income statement under Account 903 (Accounting Schedule 9). Customers are paid interest for
21 the use of the funds they provide to KCPL on a cost-free basis, and that interest expense is
22 included as an expense in the revenue requirement calculation (discussed in more detail in a
23 separate section below). The Commission should base its awarded revenue requirement on
24 Staff's recommended deduction of the most current balance for Customer Deposit funds
25 reflected in the Missouri jurisdictional total from KCPL's rate base.

26 *Staff Expert/Witness: Patricia Gaskins*

27 **G. Customer Advances**

28 Staff's recommend treatment of customer advances is to deduct the most current
29 customer advances balance, as reflected in the Missouri jurisdictional total, from KCPL's rate

1 base. Customer advances are funds typically provided by developers to KCPL in order to ensure
 2 that KCPL builds electric infrastructure in areas that have potential for future development.
 3 These advances are also used by the utility to establish electric service for potential future
 4 customers without investing a substantial amount of money at the risk of the utility and its other
 5 customers. Customer advances are included in the rate base as an offset, reducing the amount of
 6 overall investment that customers must supply as a return to the utility. (Accounting Schedule 2)
 7 The amount of customer advances reflected on Accounting Schedule 2, Rate Base, represents the
 8 last known balance of the account (balances ending March 31, 2012) of KCPL's Missouri
 9 jurisdictional contributions. The Commission should base its awarded revenue requirement on
 10 Staff's recommended deduction of the most current balance for customer advances, reflected in
 11 the Missouri jurisdictional total, from KCPL's rate base.

12 *Staff Expert/Witness: Patricia Gaskins*

13 **H. Iatan Construction Accounting Regulatory Assets**

14 The Iatan Construction Accounting Regulatory Assets are the result of various
 15 agreements approved by the Commission during the course of KCPL's Experimental Regulatory
 16 Plan. Below is a table identifying the applicable generating unit, time period, expense type, and
 17 governing document as approved by the Commission:

18

Owner	Generating Unit	Expense Type	Accumulation Period	Authorization
KCPL	Iatan 1 and Common	Depreciation, Carrying Cost, No O&M	May 1, 2009-May 4-2011	ER-2009-0089 Stipulation
KCPL	Iatan 2	Depreciation, Carrying Cost, O&M	August 26, 2010-May 4, 2011	EO-2005-0329 Stipulation

19 Pursuant to the terms of the *Non-Unanimous Stipulation and Agreement* approved by the
 20 Commission on June 10, 2009, in Case No. ER-2009-0089, KCPL was authorized to create a
 21 regulatory asset. The Commission authorized KCPL to record in that account the depreciation
 22 and carrying costs for the Iatan Unit 1 AQCS and Iatan Common Plant that was not included in
 23 KCPL's rate base in that case. Also pursuant to the terms of Stipulation and Agreement
 24 approved by the Commission on July 28, 2005 in Case No. EO-2005-0329, KCPL was
 25 authorized to create a regulatory asset. The Commission authorized KCPL to record in that
 26

1 account the depreciation, carrying costs, and other operating expenses and credits for Iatan
2 Unit 2 subsequent to its commercial in-service date of August 26, 2010.

3 Staff adjusted these regulatory assets pursuant to the Commission's Report and Order in
4 the most recent prior rate case, Case No. ER-2010-0355.

5 The Iatan Unit 1 and Common regulatory assets capturing construction accounting from
6 May 1, 2009 through December 31, 2010, the true-up cutoff in Case No. ER-2010-0355, are
7 referred to as "Vintage 1". These regulatory assets are included in Rate Base – Schedule 2 and
8 are amortized over 26 years as established in that case in Adjustment E-252.1.

9 The Iatan Unit 1 and Common regulatory assets capturing construction accounting from
10 January 1, 2011 through May 4, 2011, the effective date of rates in Case No. ER-2010-0355, are
11 referenced to as "Vintage 2". These regulatory assets are included in Rate Base – Schedule 2
12 and amortized to expense over 24.3 years, or, the 26 years reduced by the number of months
13 since the effective date of rates in Case No. ER-2010-0355 in Adjustment E-252.2.

14 The Iatan Unit 2 regulatory asset capturing construction accounting from
15 August 26, 2010 through December 31, 2010, the true-up cutoff in Case No. ER-2010-0355, is
16 referred to as "Vintage 1". This regulatory asset is included in Rate Base – Schedule 2 and is
17 amortized over 47.7 years as authorized by the Commission in that case in Adjustment E-252.3.

18 The Iatan Unit 2 regulatory asset capturing construction accounting from January 1, 2011
19 through May 4, 2011, the effective date of rates in Case No. ER-2010-0355, is referenced to
20 as "Vintage 2". This regulatory asset is included in Rate Base – Schedule 2 and amortized
21 to expense over 46 years, or, the 47.7 years as authorized by the Commission reduced by
22 the number of months since the effective date of rates in Case No. ER-2010-0355 in
23 Adjustment E-252.4.

24 *Staff Expert/Witness: Keith Majors*

25 **I. 2011 Missouri River Flood Incremental Non-Fuel Operations & Maintenance**
26 **Expense**

27 Staff recommends the Commission authorize KCPL to defer the incremental NFOM
28 expenses related to the 2011 Missouri flood into a regulatory asset with amortization over
29 5 (five) years beginning with the effective date of rates in this case. On December 19, 2011,
30 KCPL filed a request for an AAO to defer incremental non-fuel operations and maintenance

1 costs (NFOM), among other expenses, incurred by KCPL as a result of the 2011 Missouri River
2 flooding. On March 21, 2010, in its *Order Granting Motion to Consolidate*, the Commission
3 consolidated KCPL's AAO request or is it Case No. EU-2012-0130 with KCPL's pending rate
4 case, Case No. ER-2012-0174.

5 Staff Adjustment E-248.2 annualizes the recommended 5 year amortization of 2011
6 Missouri River flood incremental NFOM expenses. In its direct case, KCPL included a five year
7 amortization of incremental NFOM costs in KCPL Adjustment CS-110 2011 Missouri River
8 Flood Amortization. KCPL has identified \$2.4 million in NFOM costs in the test year,
9 \$1.4 million of which are Missouri jurisdictional expenses.

10 In prior recent instances of severe weather events, the Commission has granted the
11 deferral of actual incremental operations and maintenance expenses associated with the impact of
12 severe weather. The Commission, in File No. EU-2011-0387 and File No. GU-2011-0392,
13 authorized the deferral of incremental operations and maintenance expense related to recent
14 weather disasters. Staff's recommendation to include actual NFOM is consistent with the
15 resolution of these cases.

16 *Staff Expert/Witness: Keith Majors*

17 **VIII. Income Statement – Revenues**

18 **A. Rate Revenues**

19 **1. Introduction**

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

26 One of the major tasks in a rate case is to determine the magnitude of any deficiency
27 (or excess) between cost of service and operating revenues. Once determined, the deficiency
28 (or excess) can only be made up (or otherwise addressed) by adjusting Missouri retail rates

1 (i.e., rate revenue) prospectively. Operating Revenues are composed of Margin from Off-system
2 Sales, Other Operating Revenue and Rate Revenue.

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

8 *Staff Expert/Witness: Daniel I. Beck*

9 **2. The Development of Rate Revenue**

10 Staff's recommended treatment of developing Rate Revenue is to determine annualized,
11 normalized billing units and revenues by rate classes during the Update Period of April 1, 2011,
12 through March 31, 2012, basing Staff's calculations on known and measurable data.

13 Staff's adjustments to KCPL's Missouri jurisdiction billing units and rate revenues are
14 based upon information that is "known and measurable" through the end of the Update Period
15 (March 31, 2012). The two major categories of revenue adjustments are known as
16 "normalization" and "annualization." Normalization deals with the Update Period events that are
17 unusual and unlikely to be repeated in the years when the new rates from this case are in effect,
18 e.g., events like the Update Period weather. Annualizations are adjustments that re-state the
19 Update Period results, as if conditions known at the end of the Update Period had existed
20 throughout the entire Update Period.

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

23 *Staff Expert/Witness: Seoung Joun Won*

24 **3. Regulatory Adjustments to Billing Unit and Rate Revenue**

25 **a. Weather Normalization**

26 **i. Weather Normal Variables**

27 **Historical Data Used to Calculate Normal Weather Variables** - Each year's weather is
28 unique; and, consequently, the usage, the hourly loads, the revenue, and the fuel and purchased

1 power expense need to be adjusted to a level that would be expected under “normal” weather
2 conditions. Staff used weather observations for the Update Period of April 1, 2011, through
3 March 31, 2012, from the Kansas City International Airport (“MCI”) in Kansas City, Missouri.

4 As a measure of “normal” weather, Staff used “climate normals” (“normals”) published
5 in July 2011 by the National Climatic Data Center (“NCDC”) of the U.S. National Oceanic and
6 Atmospheric Administration (“NOAA”) as the authoritative definition of normal weather.
7 According to NOAA, a climate normal is defined, by convention, as the arithmetic mean of a
8 climatological element computed over three consecutive decades.⁶³ To conform to NOAA’s
9 three consecutive decade convention for determining normal temperatures, Staff used observed
10 maximum and minimum daily temperatures for the 30-year period of January 1, 1981, through
11 December 31, 2010, the same period in which NOAA bases its calculation of climate normal.

12 Inconsistencies and biases in the 30-year time series of daily temperature observations
13 occur if weather instruments are relocated, replaced, or recalibrated. Changes in observation
14 procedures or in an instrument’s environment may also occur during the 30-year period. NOAA
15 accounted for these anomalies in calculating the normal temperatures it published in July 2011.
16 Staff verified the adjustments for anomalies in the MCI time series by direct communication with
17 NCDC, and through Staff’s own review of the daily observations. NCDC confirmed that the
18 serially-complete monthly minimum and maximum temperature data sets have been adjusted to
19 remove all inconsistencies and biases due to changes in the associated historical database. In
20 addition, NCDC provided a peer-reviewed, published paper⁶⁴ to explain the meteorological and
21 statistical soundness of the NCDC’s monthly temperature series homogenization procedure for
22 removing documented and undocumented anomalies.

23 Because Staff used daily temperature observations to calculate normal weather values
24 and NOAA’s normals are monthly values, Staff adjusted the observed daily minimum
25 temperatures so that the monthly average minimum temperature calculated from these adjusted
26 daily values is the same as the NCDC’s serially-complete monthly minimum temperature time
27 series. Staff derived the daily mean temperature time series, daily two-day weighted mean
28 temperatures, and normal daily temperatures from these adjusted daily temperatures.

63 Retrieved on July 17, 2012, from NOAA website, <http://www.ncdc.noaa.gov/oa/climate/normals/usnormals.html>.

64 Menne, M.J., and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, 22, 1700-1717.

1 **Weather Variables** - Because weather fluctuates greatly from day-to-day, the MCI
2 temperature variables required to weather-normalize sales are the Update Period actual
3 temperatures and the 30-year normal two-day weighted daily mean temperatures. The day's
4 daily mean temperature is generally defined as the simple average of the day's maximum daily
5 temperature and minimum daily temperature. The daily two-day weighted mean temperature is
6 calculated using the previous day's mean daily temperature with a one-third weight and the
7 current day's mean daily temperature with a two-thirds weight.⁶⁵

8 This weighted mean is used because yesterday's weather effects how electricity is used
9 today. For example, if yesterday was hot and the air conditioner was on, it is more likely that the
10 air conditioner will be left on today. If yesterday was a mild day and today is slightly hotter, air
11 conditioning may not be used or would be turned on later in the day.

12 **Calculation of "Normal Weather"** - Staff used the MCI daily two-day weighted mean
13 temperature data series to normalize both class usage and hourly net system loads. Staff used a
14 ranking method to calculate normal weather estimates daily normal temperature values, ranging
15 from the temperature that is "normally" the hottest to the temperature that is "normally" the
16 coldest, thus estimating "normal extremes." Staff ranked the two-day weighted temperatures for
17 each year of the 30-year history from hottest to coldest and then calculated the normal daily
18 temperature values by averaging the ranked two-day weighted mean temperatures for each rank,
19 irrespective of the calendar date. This method results in the normal extreme being the average of
20 the most extreme temperatures in each year of the 30-year period. The second most extreme
21 temperature is based on the average of the second most extreme day of each year, and so forth.

22 Because actual temperatures do not smoothly move up and down from day to day during
23 the year,⁶⁶ Staff assigned these normal temperatures to the days of the Update Period based on
24 the rankings of the actual temperatures of the Update Period.

25 This information was used by Staff witness Shawn E. Lange to normalize both the class
26 kWh usage and hourly net system loads.

27 *Staff Expert/Witness: Seoung Joun Won*

65 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: $TWMT_D = (2/3) DMT_D + (1/3) DMT_{D-1}$.

66 For example, in July, a Monday and Tuesday may be hot days but it cools down on Wednesday. However, it is still likely that on the weekend it will be hot again.

1 necessary to annualize rather than normalize LPS for changes in customer usage and count.
2 Please see *Large Power Annualization* by Staff witness Seoung Joun Won for a more detailed
3 explanation of the annualization adjustments for the LPS class. Applying the weather
4 normalization process to annualized usage would have introduced statistical error into the
5 product of the analysis.

6 *Staff Expert/Witness: Shawn E. Lange*

7 **iii. The Effect of the Weather Normalization on Rate Revenue**

8 To calculate weather-normalized revenue, Staff applied current rates to weather
9 normalized usage provided by Staff witness Shawn E. Lange. Staff's weather normalization
10 revenue adjustment is equal to the difference between weather-normalized revenue and the
11 Update Period revenue.

12 The weather normalization process assumes that weather has no effect on either the
13 number of customers or on the fixed charges these customers currently pay. Weather variations
14 only affect the energy usage of each existing customer and, thus, weather normalization only
15 changes revenue directly related to usage. Staff reviewed and accepted KCPL's adjusted usage
16 for rate switchers⁶⁷ prior to weather normalization.

17 *Staff Expert/Witness: Seoung Joun Won*

18 **b. Annualization for Rate Change**

19 Staff annualized current rates, which became effective May 4, 2011, to reflect
20 a full year's revenues at those rates. The Update Period revenues reflect rates prior to
21 May 4, 2011, and the current rate on and after May 4, 2011, which were established in Case No.
22 ER-2010-0355. Thus, for all rate classes, the Update Period revenues are understated by the
23 difference between the amount that was actually billed to customers and the revenue that would
24 have been realized by the Company, if the current rates (May 4, 2011, to present) had been in
25 effect throughout the entire Update Period. Staff computed annualized revenues based on
26 May 4, 2011, rates for each rate class by applying these new rates to the Update Period
27 annualized, normalized billing units for each class.

28 *Staff Expert/Witness: Seoung Joun Won*

67 Rate Switchers are primarily industrial and commercial customer accounts that switch between different rate groups that better suits their consumption pattern.

1 **c. 365-Days Adjustment**

2 **i. 365-Days Adjustment to Usage of Weather Sensitive Classes**

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

13 The length of a revenue month is dependent upon the interval between meter readings
14 and does not necessarily have the same number of days that occur in a given calendar month of
15 the same name; that is, a revenue month may have more than or less than the number of days for
16 the same-named calendar month. For the example given above, the usage is for 30 days
17 (June 9 through July 8) even though the revenue month is July which has 31 days. When
18 revenue month usage is totaled over the year, the resulting revenue year will include usage from
19 the immediately prior calendar year and assign usage to the next calendar year, meaning a
20 revenue year may contain more than or less than 365 days' usage. Therefore, since the costs and
21 expenses are accounted over a calendar year, Staff calculates an annualization adjustment to
22 bring the revenue year kWh into a 365-days interval. This adjustment is stated in kWh is
23 referred to as *365-Days Adjustment*.⁶⁸

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

27 The *365-Days Adjustment* for the weather sensitive classes were provided to Staff witness
28 Seoung Joun Won who used the *365-Days Adjustment* to adjust the revenues of the weather
29 normalized class revenues months to the twelve months ended March 30, 2012.

30 *Staff Expert/Witness: Shawn E. Lange*

68 Days adjustments are also known as adjustments to unbilled usage and unbilled revenues on financial statements.

1 known and measurable changes through March 31, 2012. A review of the pertinent facts as of
2 March 31, 2012, indicates that KCPL experienced a decrease in its overall growth in the number
3 of its utility customers. For Residential and General Service (Small, Medium, and Large) retail
4 customer groups, Staff employed the following method of computing the annualized level of
5 decreased revenue from customer growth at March 31, 2012: For each customer rate group, the
6 customer level during each month of the test year is compared to the level as of March 31, 2012,
7 and the monthly change in level is computed. This growth in customers is then multiplied by the
8 weather-normalized revenue per customer experienced for that month of the test year. In this
9 case, weather-normalized revenue was based on the twelve (12) month period April 1, 2011,
10 through March 31, 2012.

11 Staff's approach assumes that the revenue pattern experienced in each month of the test
12 year will recur on a weather-normalized basis, factored up (or down) in accordance with the
13 growth (or decrease) in customer numbers at March 31, 2012.

14 The only retail customer rate group for which this approach is not taken is the Large
15 Power group. With respect to Large Power customers, energy consumption and revenue patterns
16 vary significantly across this group of customers, making it necessary to examine the history of
17 each customer on an individual basis, and to adjust the test year revenue level accordingly. Staff
18 witness Seoung Joun Won addresses the Large Power revenue annualization. Staff's customer
19 growth adjustment to test year revenues for all retail customer groups combines the results of the
20 analysis described above for Residential, General Service, and Large Power customers in order
21 to provide the annualized level as of March 31, 2012. The retail customer growth adjustment
22 other than Large Power is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-2.2.

23 *Staff Expert/Witness: Karen Lyons*

24 **D. Customer Growth in Usage**

25 Staff adjusted the Update Period usage and rate revenue for the Missouri jurisdiction for
26 customer growth to reflect the additional usage and rate revenue that would have occurred, if the
27 number of customers taking service at the end of the Update Period (March 31, 2012) had
28 existed throughout the entire Update Period using the information provided by Staff witness
29 Karen Lyons. Staff calculated customer growth in revenues for KCPL's Missouri jurisdiction's

1 Residential Service, Small General Service, Medium General Service, and Large General Service
2 rate classes only.

3 Staff also applied customer growth adjustments to usage in KCPL's Kansas jurisdiction
4 to be used along with the Missouri adjusted usage in the calculation of the jurisdictional
5 allocation factor which will be addressed by Staff witness Alan J. Bax.

6 *Staff Expert/Witness: Seoung Joun Won*

7 **E. Large Customer Adjustments**

8 Because each LPS customer uses significant amounts of electricity, and the class is
9 heterogeneous in electric use and load factor, class usages and revenues were annualized on an
10 individual customer account basis. LPS customer revenues were annualized for major growth or
11 decline in kWh sales and rate revenues due to the entrance of new customers, the exit of existing
12 customers, and load growth or decline of specific existing customers active at the end of the
13 Update Period (March 31, 2012).

14 Staff analyzed LPS customer data during the test year and through the Update Period. A
15 data check for billing corrections was done prior to making any adjustments. Each customer's
16 individual monthly demand and energy use, measured over multiple years prior to and including
17 the twelve months of the Update Period, were examined graphically to determine whether an
18 adjustment was needed.

19 At the beginning of the Update Period there were eighty-three LPS customers, and at the
20 end of the Update Period, there were eighty-two. One customer switched out of the LPS rate
21 class and into the Large General Service (LGS) rate class. Therefore, the total LPS customer
22 load was reduced by the total load of the above mentioned customer that switched rate classes.
23 In addition, a review of the current customer loads showed that the current loads of some
24 customers needed to be adjusted due to abnormal usage in the Update Period. Staff calculated an
25 annualization adjustment for this abnormal usage in the Update Period.

26 In KCPL's Kansas jurisdiction, there were three LPS customers in the rate group during
27 the Update Period. This information is used along with the Missouri adjusted usage in the
28 calculation of Staff's jurisdictional allocation factor which will be addressed by Staff witness
29 Alan J. Bax.

30 *Staff Expert/Witness: Seoung Joun Won*

1 attaining that level of OSS margins or higher. In KCPL Case No. ER-2010-0355, the
 2 Commission ordered the use of Mr. Schnitzer's projected net margin at a 40th percentile level,
 3 due largely to the added generation available to KCPL from the Iatan 2 Unit's being placed in
 4 service in August 2010 as well as a projected increase in Wolf Creek's generating capacity.
 5 Mr. Schnitzer has updated his analysis for this case and filed his findings on February 27, 2012,
 6 as part of the Company's original direct filing. Staff has included Mr. Schnitzer's original
 7 projected level of net margin of ** ____ ** million, total company, at the 40th percentile in
 8 determining KCPL's cost of service for this direct filing. As has happened in past KCPL's
 9 rate cases, updates to the off-system sales is expected as this case progresses. Staff will continue
 10 to evaluate off-system sales net margins and update its recommendation for the true-up filing in
 11 this case.

The off-system sales levels since 2006 have been as follows: Year	Off-System Sales Total Company	Net Margin
2006	\$ 158,982,025	\$ 87,282,307
2007	\$ 158,739,779	\$ 64,087,726
2008	\$ 102,956,374	\$ 56,056,149
2009	\$ 91,878,117	\$ 32,424,214
2010	\$ 132,833,603	\$ 33,332,670
2011	\$ 140,319,060	\$ 26,233,269

12
 13 At page 36 of its *Report and Order and Order Regarding Motions for Rehearing* in
 14 Case No. ER-2006-0314, the Commission ordered the utility to track the OSS net margin
 15 included in cost of service with KCPL's actual OSS net margin, and to flow back the excess to
 16 ratepayers as a reduction to cost of service. In KCPL's next three rate cases, ER-2007-0291,
 17 ER-2009-0089 and ER-2010-0355, the Commission ordered a continuation of the net margin
 18 tracking mechanism the Commission originally ordered in Case No. ER-2006-0314. Adjustment
 19 Rev-12.1 reflects the adjustment to non-firm off-system sales levels.

NP

1 Please refer to **Excess Off-System Sales Margin Regulatory Liability** section below
2 for a complete discussion regarding the Staff's proposed treatment of the net margin
3 tracking mechanism.

4 *Staff Expert/Witness: V. William Harris*

5 **5. Adjustments to Non-Firm OSS**

6 Staff recommends the following three adjustments to non-firm OSS:

- 7 (1) Purchases for Resale – wholesale sales that are supplied by purchased
8 power as compared to wholesale sales supplied by KCPL owned
9 generation.
- 10 (2) Southwest Power Pool (“SPP”) line loss charges (net of line loss revenue).
- 11 (3) SPP’s Revenue Neutrality Uplift (“RNU”) charges – imbalances between
12 revenues and disbursements that are distributed among SPP market
13 participants as either a charge or a credit.

14 Staff has determined the appropriate amounts of adjustments to include in KCPL’s cost
15 of service calculation in this direct filing and will update the adjustment amounts in its true-up
16 filing. KCPL made similar adjustments in its direct filing.

17 Staff also recommends the following (fourth) adjustment to non-firm OSS, which was not
18 proposed by KCPL in its direct filing:

- 19 (4) Q sales, referred to as “book-outs” or “non-asset sales” on KCPL’s
20 Wholesale Reports – wholesale sales from transactions occurring
21 outside KCPL’s generation or transmission system. While generating
22 assets paid for by ratepayers through rates are not being used to
23 support these sales, other KCPL assets paid for by ratepayers are being
24 expended to realize the net margins on these wholesale sales. KCPL
25 personnel, software programs to execute sale transaction, billing and
26 collection systems, accounting and record-keeping processes all are
27 necessary to make these sales.

28 Staff has included an adjusted level of OSS in KCPL’s cost of service calculation in this
29 direct filing and will update the adjustment amount in its true-up filing.

30 *Staff Expert/Witness: V. William Harris*

1 Off-System Sales ("OSS") Margins—Excess Over 25th Percentile for
2 2007 and 2008

3 The Signatory Parties agree that the \$1,082,974 (Missouri jurisdictional)
4 excess of 2007 OSS margins over the amount included in rates in
5 Case No. ER-2006-0314 and the \$2,947,332 (Missouri jurisdictional)
6 excess of 2008 OSS margins over the amount included in rates in
7 Case No. ER-2007-0291, together with interest (Missouri jurisdictional),
8 will be deferred in a regulatory liability account and amortized over ten
9 years beginning with the date new rates become effective in this rate case,
10 with one year's amortization included in cost of service in this case. The
11 unamortized balance will not be included in rate base.

12 Off-System Sales Tracker

13 KCP&L's OSS margins at the 25th percentile shall be set at \$30 million,
14 and shall be used for tracking purposes. Such tracker will reflect a
15 pro-ration, on a monthly basis, of this amount for any partial years
16 consistent with the percent of actual OSS realized in each month of 2008.
17 All OSS margins will be tracked against the \$30 million baseline.

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

24 Staff has calculated the amount of KCPL's amortization and interest related to this
25 regulatory liability from the 2006, 2007 and 2009 rate cases and reflected the appropriate
26 amounts in Adjustments Rev-4.1 and Rev-18.1.

27 *Staff Expert/Witness: V. William Harris*

28 **H. SO2 Emissions Allowances**

29 **1. Deferred Sales from SO2 Emissions Allowances**

30 Since KCPL receives more SO2 emission allowances ("SO2 allowances") from the
31 U.S. Environmental Protection Agency ("EPA") than it requires for its own coal-burning
32 operations, it may sell all or part of these surplus allowances. Under the FERC Uniform System
33 of Accounts ("USOA"), proceeds from the sales of surplus SO2 emissions allowances are

1 recorded in FERC Account 254, the USOA regulatory liabilities account. For ratemaking
2 purposes, amounts recorded as regulatory liabilities reduce a utility's rate base, i.e., the net
3 amount in FERC Account 254, after any appropriate adjustments, is an offset to rate base.

4 Staff included in its direct case the balance of Account 254 on March 31, 2012, as
5 an offset to rate base found on Staff Accounting Schedule 2 filed with this direct filing.
6 This approach is consistent with the treatment in the last four KCPL rate cases, Case Nos.
7 ER-2006-0314, ER-2007-0291, ER-2009-0089 and ER-2010-0355. Treating these SO2
8 emissions allowances in this manner acknowledges that, through rates, KCPL's customers have
9 paid for KCPL's production facilities that create these SO2 emissions allowances, which KCPL
10 is able to sell to other entities for profit.

11 *Staff Expert/Witness: V. William Harris*

12 **I. Miscellaneous Revenues**

13 **1. Late Payment Revenue (Forfeited Discount)**

14 KCPL charges a late payment fee to customers who fail to pay bills in a timely manner.
15 Staff annualized late payment fee revenues by using the ratio of late payment fees to
16 Missouri Total Retail Sales both net of gross receipt taxes (GRT) from April 1, 2011, through
17 March 31, 2012. This ratio was multiplied by the Staff annualized revenue resulting in an
18 annualized level of late payment fees. This is reflected in the Staff Accounting Schedule 9 as
19 Adjustment Rev-19.2.

20 *Staff Expert/Witness: Karen Lyons*

21 **J. Other Revenue Accounts**

22 Staff reviewed the amounts KCPL included in its cost of service calculation for
23 "Other Revenues," which include rent from electric property, miscellaneous service
24 revenues and temporary installation profit. Staff has also included revenue related to
25 transmission at the test year level. The analysis of these amounts included a review of the
26 revenues over the last ten years through March 31, 2012. In Staff's opinion, the test year
27 amounts for Other Revenues appeared to be representative and reasonable of an annualized level
28 of revenue for each respective category and, therefore, do not require adjustment. However,
29 Staff will apply its own allocation factors to those amounts that are common to other KCPL's

1 operational jurisdictions. Staff will examine these revenue accounts again during its true-up
2 audit through August 31, 2012.

3 *Staff Expert/Witness: Karen Lyons*

4 **K. Removal of Gross Receipts Taxes from Test Year Revenues**

5 The amounts received from customer payments and recorded as revenues during the test
6 year include Gross Receipts Taxes. GRTs are imposed by a taxing authority for which KCPL is
7 obligated to charge customers on their utility bills. After KCPL collects these taxes from its
8 customers, the Company periodically remits these amounts to the appropriate taxing authority.
9 In this regard, to accurately account for KCPL's actual test year retail revenues – it is necessary
10 to remove GRT from the amounts recorded as revenues during the test year – while at the same
11 time removing the corresponding remittances to the taxing authority as a charge to expenses. In
12 effect, GRT will have no impact on the Company's final revenue requirement amount. Staff's
13 adjustments remove GRT from test year revenues and expenses and are reflected in Staff's
14 Accounting Schedule 9, Rev-3.1, Rev-19.1 and E-260.1.

15 *Staff Expert/Witness: Karen Lyons*

16 **L. Regulatory Adjustments Result**

17 Normalization and annualization adjustments along with a Rate Revenue summary for
18 KCPL's Missouri jurisdiction can be found as an attachment to the Staff Accounting Schedule.

19 *Staff Expert/Witness: Seoung Joun Won*

20 **IX. Income Statement – Expenses**

21 **A. Fuel and Purchased Power Expense**

22 The Staff estimates the variable fuel and purchased power expense for KCPL for the
23 twelve months ending March 30, 2012, to be \$ 232,593,957.

24 In determining the variable and fuel purchased power expense, Staff used the
25 RealTime™ production cost model to perform an hour-by-hour chronological simulation of a
26 utility's generation and power purchases. The Staff used this model to determine the annual
27 variable cost of fuel, the net purchased power energy costs, and the fuel consumption necessary

1 to economically meet a utility's load within the operating constraints of the utility's resources.
2 These amounts are supplied to the Auditing Department Staff who used this input in the
3 annualization of fuel expense.

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

10 Inputs calculated by the Staff are fuel prices, firm purchased power contract
11 specifications, spot market purchased power prices and availability, hourly Net System Input (NSI),
12 and unit planned and forced outages. The Staff relied on KCPL responses to data requests, and
13 data KCPL supplied to comply with Rule 4 CSR 240-3.190, for factors relating to each
14 generating unit such as capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-
15 up rate, startup costs, fixed operating and maintenance expense. Information from KCPL's firm
16 wholesale loads and firm purchased power contracts such as hourly energy available and prices
17 are also inputs to the model.

18 *Staff Expert/Witness: Shawn E. Lange*

19 **1. Fixed Costs**

20 Fuel and purchased power costs that do not vary directly with fuel burned were not
21 included in Staff's fuel model, but were determined separately. The non-variable fuel costs that
22 were determined separately and included in fuel expense are typically referred to as "fuel
23 adders." The non-variable purchased power costs not included in Staff's fuel model are
24 commonly referred to as "capacity charges" and are annualized separately from purchased power
25 energy costs.

26 *Staff Expert/Witness: Keith Majors*

27 **2. Fixed Adders**

28 As described above, fuel adders do not vary directly with the amount of electricity
29 produced, so these costs are not included in Staff's fuel model. The costs of fuel adders are

1 determined separately and are added to the level of fuel expense calculated by the model to
2 determine overall fuel expense. Costs added to coal expense include unit train lease payments
3 and unit train maintenance costs. Fuel adders for natural gas include transportation charges and
4 hedging costs. A significant percentage of natural gas transportation charges is fixed and under
5 contract.

6 For natural gas fixed transportation costs, Staff used the actual expenses for the
7 12 –months ending March 31, 2012. For additives such as limestone and ammonia, Staff used
8 the calendar year 2011 actual expenses. Staff will update these expenses for at the time of
9 Staff's true-up.

10 *Staff Expert/Witness: Keith Majors*

11 **3. Purchased Power – Energy**

12 Staff Adjustment E-112.1 annualizes purchased power energy charges based on Staff's
13 fuel model results. These purchased power energy charges represent the energy KCPL purchases
14 on the spot market and through contracts to meet the system load requirements of its retail
15 electric customers. Staff witness Shawn E. Lange is responsible for determining the appropriate
16 amount of purchased power and the proper price for this power.

17 *Staff Expert/Witness: Keith Majors*

18 **4. Purchased Power – Capacity Charges**

19 Capacity charges, commonly referred to as “demand charges,” represent fixed amounts
20 that KCPL paid to the entity that reserves megawatt electric capacity for KCPL. KCPL contracts
21 this power with various entities and pays a fixed component for the reserve capacity and an
22 energy component for energy consumed. Generally, there is also an amount for operational and
23 maintenance costs charged for the usage of energy. The fixed component is paid by KCPL as a
24 demand charge, generally on a monthly basis, regardless of the level of power actually
25 purchased. This amount is for the “right” to purchase the power in much the same way that
26 natural gas utilities purchase the reservation of capacity from pipelines through reservation
27 payments. The demand charges relate to the fixed expenses of operating a generating facility.

28 Staff Adjustment E-113.1 annualizes purchased power demand charges based on existing
29 capacity contracts in effect. These charges represent amounts that are paid under capacity

1 agreements related to the fixed costs of reserving capacity. Staff reviewed each of these
2 contracts and determined the appropriate costs per megawatt hour and the amount of megawatts
3 purchased. Staff included the costs reflected in KCPL's capacity agreements that were in effect
4 on March 31, 2012.

5 *Staff Expert/Witness: Keith Majors*

6 **5. Variable Costs**

7 **a. Fuel Prices**

8 Staff computed fuel expense using prices and quantities actually incurred by KCPL as of
9 March 31, 2012. This included using fuel prices for nuclear coal, natural gas, and oil, including
10 transportation charges in fuel accounts 501 (coal), 518 (nuclear), and 547 (natural gas).

11 *Staff Expert/Witness: Keith Majors*

12 **b. Coal Prices**

13 Staff determined its coal price by generation facility based on a review and analysis of
14 KCPL's coal purchase (supply) and coal transportation (freight) contracts. Staff's recommended
15 coal prices reflect KCPL's actual contracted coal purchase and transportation prices (excluding
16 sulfur premiums or discounts) in effect on March 31, 2012.

17 *Staff Expert/Witness: Keith Majors*

18 **c. Natural Gas Prices**

19 As an input to its production cost model, Staff used twelve (12) monthly natural gas
20 prices calculated using 12 month weighted averages of KCPL's actual commodity cost of natural
21 gas through the known and measurable period updated through March 31, 2012. KCPL's natural
22 gas fixed transportation costs are annualized and normalized separately as a part of fuel adders.

23 *Staff Expert/Witness: Keith Majors*

24 **d. Nuclear Fuel Prices**

25 KCPL owns 47% of Wolf Creek, the operating company for the Wolf Creek nuclear
26 plant. KCPL's 47% ownership interest in Wolf Creek entitles it to 547 megawatts of the plant's
27 capacity. In making its nuclear fuel price adjustment, Staff relied upon KCPL's monthly Report
28 25, Fuel Report, for October 2010 through March 2012. Staff noted that monthly nuclear fuel

1 costs over the prior several years varied within a small range. Staff's proposed nuclear fuel price
2 is based on the most current fuel price as of March 2012.

3 *Staff Expert/Witness: Keith Majors*

4 **e. Oil Prices**

5 Staff used the actual cost KCPL paid for its most recent fuel oil purchases to determine
6 variable fuel oil expense. KCPL burns fuel oil mainly as a secondary fuel or, in some instances,
7 for flame stabilization. Oil is a primary fuel source at KCPL's Northeast units, which see very
8 limited run time. As a result, KCPL purchases fuel oil infrequently. The limited number of
9 purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An
10 accurate historical analysis of fuel oil prices is also not possible because KCPL does not make
11 purchases during the majority of the year. For its direct filed case, Staff recommends KCPL's
12 most recent fuel oil purchase prices at its Montrose Generating Station are the best available fuel
13 oil cost to input into the fuel model for determining KCPL's variable fuel and purchased power
14 expense on a going forward basis. In discussion with KCPL personnel, the Company has not
15 purchased significant quantities of fuel oil for several months at its other generating stations.
16 However, at the time of the true-up in this case, it is expected that significant quantities of fuel
17 oil at its other generating stations will be purchased with differing delivered prices.

18 *Staff Expert/Witness: Keith Majors*

19 **6. Spot Market Prices**

20 Spot market purchases are purchases of energy made by a utility on an hourly basis rather
21 than through a long-term contract. A utility decides to buy spot energy based on the economic
22 environment and the availability of its generating units and long-term capacity contract
23 purchases. The purpose of making spot market purchases is to lower overall generation costs
24 when the spot market price is below both the marginal cost of providing that energy from the
25 company's generating units and the utility's firm capacity purchases.

26 Staff used a procedure developed by the Engineering Section of the Commission's
27 Energy Department and attached here as Appendix 3, Schedule ELM-1, to calculate
28 representative prices for purchased power in the spot market. This method uses a statistical

1 calculation based on the truncated normal distribution curve of hourly data by month to represent
2 the hourly purchased power prices in the spot market for each hour in the test period.

3 The actual hourly non-contract transaction prices for KCPL and GMO during the year
4 ending March 30, 2012 are the prices used as inputs to Staff's calculation. These prices were
5 obtained from the data that the Company supplied to Staff in compliance with Rule 4 CSR
6 240-3.190 Reporting Requirements for Electric Utilities and Rural Electric Cooperatives. The
7 calculation yields a spot energy price for each hour of the year. This data set containing
8 8,760 hourly spot energy prices is then used as one of the inputs to Staff's RealTime®
9 production cost model. These prices may be inflated by the Missouri river flooding conditions
10 which occurred during the summer of 2011. Staff will review spot energy prices through the
11 true-up period ending August 31, 2012 to update the inputs as necessary.

12 *Staff Expert/Witness: Erin L. Maloney*

13 **7. Capacity Contract Prices and Energy**

14 Capacity contracts are contracts between two utilities for a specific amount of capacity
15 and a maximum amount of hourly energy. Energy for two of the capacity contracts held by
16 KCPL are purchased at market prices. They were not included in the production cost model
17 because the model would not differentiate between the contracts and the purchases made on the
18 spot market. Two other contracts are for energy from units which can be dispatched by KCPL.
19 Those two units are included in the production cost model as dispatchable units.

20 *Staff Expert/Witness: Shawn E. Lange*

21 **8. Planned and Forced Outages**

22 Planned and forced outages affect what units are available for dispatch to meet load.
23 Planned and forced outages are infrequent in occurrence, and variable in duration. In order to
24 capture this variability, most KCPL generating unit outages were normalized by averaging the
25 seven years of actual values taken from the data supplied by KCPL. Any derates on account of
26 flooding in 2011 were normalized out as this will be addressed in KCPL's AAO. The seven year
27 average forced outage rate for Wolf Creek was larger than normal. Staff made a normalization
28 adjustment to better reflect the forced outage rate for Wolf Creek on a prospective basis. Staff

1 made adjustments to the Hawthorn 5 force outage rate and planned outage duration to reflect the
2 adjustments proposed in the section of this report titled "Other Non-Labor Adjustments."

3 *Staff Expert/Witness: Shawn E. Lange*

4 **9. Normalization of Hourly Net System Load**

5 Staff's recommended treatment of determining appropriate fuel and purchase power
6 expenses is to normalize revenues on an annual basis and apply an adjustment factor to each hour
7 of weather-normalized loads to produce the annual requirement of the net system load for usage
8 during the Update Period.⁶⁹ Staff's normalization of hourly net system load includes a
9 calculation using separate weather-normalization adjustments for average daily loads and daily
10 peaks. Additionally, Staff normalizes the hourly net system load to determine weather-
11 normalized hourly net system loads that equal the adjusted test year usage, plus losses. Staff's
12 normalization of hourly Net System loads allocates the system losses (more to hotter days, less to
13 more mild days), more like they would normally occur.

14 Hourly net system load is the hourly electric supply necessary to meet the energy hourly
15 demands of both the company's customers and the company's own internal needs.⁷⁰ Staff
16 calculates an average net system load and an average daily peak load to adjust for fluctuations in
17 energy consumption, where usage may be responsive to differences in factors such as
18 temperatures, seasons, holidays, and times of day.

19 Weather conditions influence energy consumption. Due to the presence of air
20 conditioning and the presence of significant electric space heating in KCPL's service territory,
21 the magnitude and shape of KCPL's net system input is directly related to daily temperatures.
22 Actual and normal daily temperatures provided by Staff witness Seoung Joun Won are used in
23 the analysis. The actual daily temperatures during the Update Period differed from normal daily
24 temperatures. Therefore, to reflect normal weather, daily peak and average net system loads are
25 each adjusted independently, but using the same methodology.

26 Daily average load is the total daily energy demand, divided by twenty-four hours. The
27 daily peak load is the maximum hourly energy use, measured for that day. Separate regression

69 Update Period: April 1, 2011 through March 31, 2012.

70 Net system loads are produced to meet the demand requirement for electricity, but the net usage does not include KCPL's station use.

1 models are used to calculate both: 1.) a base component, which is allowed to fluctuate across
2 time; and 2.) a weather sensitive component, which measures the response to daily fluctuations
3 in weather for daily average loads and peak loads. Independent regression models are necessary
4 because daily average loads respond differently to weather than peak loads do. The models'
5 regression parameters, along with the difference between normal and actual cooling and heating
6 measures, are used to calculate weather adjustments to both the average and peak loads for each
7 day. The adjustments for each day are added respectively to the actual average and to the peak
8 loads of each day.

9 The starting point for allocating the weather-normalized daily peak and average loads to
10 the hours is the actual hourly loads for the year being normalized. A unitized load curve is
11 calculated for each day as a function of the actual peak and average loads for that day.
12 This process includes many checks and balances, which are included in the spreadsheets that
13 are used by Staff. In addition, the analyst is required to examine the data at several points in
14 the process.⁷¹ The corresponding weather-normalized daily peak and average loads, along with
15 the unitized load curves, are used to calculate weather-normalized hourly loads for each hour of
16 the year.

17 An adjustment factor is created by dividing the aggregate of weather-normalized and
18 annualized usage for KCPL's retail customer classes, weather-normalized wholesale usage, plus
19 losses by the annual level of weather-normalized net system input. This factor was applied to
20 each hour of the weather-normalized loads to produce an annual sum of the hourly net-system
21 loads that is consistent with normalized revenues

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

25 The Commission should determine the awarded revenue requirement, including Staff's
26 recommended level of ongoing fuel and purchased power expenses, using Staff's methodology
27 of calculating the normalized hourly net system load based upon data from the Update Period.

28 *Staff Expert/Witness: Shawn E. Lange*

71 For more information, the process is described in greater detail in the document, *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.

1 **10. Losses**

2 KCPL's system energy losses largely consist of the energy losses that occur in
3 the electrical equipment of KCPL's system (e.g., transformers, transmission and distribution
4 lines, etc.) between its generating sources and the customers' meters. In addition, small
5 fractional amounts of energy, either stolen (diversion) or not metered, are included in Staff's
6 quantification of system energy losses.

7 Staff calculates system energy losses as a percentage of Net System Input (NSI), where
8 NSI is equal to the kWh sum of KCPL's retail and wholesale sales, plus the electrical energy
9 KCPL used in the operation of its facilities (Company Use⁷²), plus system energy losses. In
10 other words, NSI = Retail Sales + Wholesale Sales + Company Use + System Energy Losses.
11 This equation may be rearranged to solve for system energy losses as follows:

12
$$\text{System energy losses} = \text{NSI} - (\text{Retail Sales} + \text{Wholesale Sales} + \text{Company Use})$$

13 NSI is also equal to the sum of net generation, plus the net of off-system purchases and
14 sales (net interchange). Net generation and net interchange are known quantities as are Retail
15 Sales, Wholesale Sales and Company Use. Therefore, by inputting these components into the
16 above equation, one can solve for system energy losses. Staff then divides the resulting system
17 energy losses by NSI and multiplies by 100 ((system energy losses/NSI) X 100%) to obtain the
18 system energy losses as a percentage of NSI. This result is referred to as the system energy loss
19 factor, or sometimes called the line loss factor.

20 Staff has calculated a system energy loss factor for the twelve months ending March 2012
21 of 5.86% of its NSI. This is the line loss percentage provided to Staff Witness Shawn E. Lange
22 and used in developing the system loads that are inputted into Staff's fuel model.

23 *Staff Expert/Witness: Alan J. Bax*

24 **B. Payroll, Payroll Related Benefits including 401k Benefit Costs**

25 **1. Payroll Costs**

26 Staff recommends allocating payroll costs using KCPL's actual assigned payroll costs for
27 the test year. Staff recommends using actual employee levels as of the update period on

72 "Company Use" does not include station use.

1 March 31, 2012, for annualizing payroll costs, with the exception of the Local 1613 Union
2 employees. Staff has examined the payroll costs of KCPL. All employees of Great Plains Energy
3 are considered employees of KCPL. These KCPL and GPE employees perform all services for
4 Great Plains Energy, KCPL and GMO (including both rate districts, MPS and L&P). An
5 allocation of costs is necessary to assign a proper amount of payroll costs to each of the Great
6 Plains Energy entities and rate districts. Staff has reviewed the allocation of actual assigned
7 payroll costs for each of these entities, since the acquisition of the former Aquila Missouri
8 electric operations and allocated the annualized payroll based on this allocation.

9 The transfer of former Aquila employees was made at the close of the acquisition
10 transaction on July 14, 2008. Because all former Aquila employees providing service to GMO's
11 electric and steam operations became part of the KCPL base, KCPL now has to allocate costs
12 directly to each KCPL service territory and the two GMO rate districts, MPS and L&P.
13 Additionally, L&P operations supplies utility services to electric and steam customers and L&P
14 labor costs must be allocated between the electric and steam operations.

15 Based on the other allocation amounts to the GPE entities, Staff concluded that the actual
16 charged amounts were the best allocation of payroll between KCPL, MPS, and L&P. Staff
17 utilized actual charged amounts to the three operating entities, net of joint partners, Wolf Creek,
18 and Jeffrey Energy Center charged payroll. The joint partners' costs are amounts charged to
19 KCPL's other partners of the generating assets owned and operated by the Company, with the
20 exception of Wolf Creek, a separate operating company 47.5% of which is owned by KCPL.

21 Staff annualized payroll costs in this case using actual employee levels as of the update
22 period on March 31, 2012, with the exception of the Local 1613 Union. The union expense was
23 annualized as of April 1, 2012 to incorporate a 3.5% increase in pay. Wages and salaries were
24 applied to each individual employee to compute the total GPE and KCPL payroll costs on an
25 annual basis. Annualized payroll included differential and premium pay, paid to KCPL
26 employees based on union contracts.

27 As of March 31, 2012, KCPL's holding company, GPE, has a portion of costs that are to
28 be annualized using current employee levels and current salaries. GPE provides common
29 services such as accounting, tax consolidation, corporate legal, and governance to GPE entities.
30 The amount of GPE payroll that relates to KCPL and the GMO entities had to be determined in
31 order to include those costs in the total payroll.

1 On December 16, 2008, GPE was restructured with all GPE and GPES employees
2 becoming KCPL employees. Because of this restructuring, the allocations factors
3 between KCPL, GMO, and GPE result in GPE having a small portion to account for the above
4 mentioned duties.

5 Overtime payroll for KCPL was calculated on a 4 year average and the overtime payroll
6 billed to KCPL from the Wolf Creek generating facility was calculated using a 3 year average.
7 These particular timeframes were chosen because the overtime hours and sum paid out indicated
8 an upward trend with the overtime costs beginning around the 2007 to 2008 timeframe. These
9 amounts are specific to KCPL, MPS, and L&P service territories and, therefore, it is not
10 necessary to include the overtime as part of the allocation process for annualized payroll. The
11 payroll overtime costs have been directly assigned to KCPL, MPS, and L&P.

12 As the result of KCPL's operating agreements for generating facilities with several
13 partners, it is necessary to assign costs to these partners and remove those payroll costs from the
14 payroll annualization that is reflected in the revenue requirement calculations. This assignment
15 of joint partner billings is necessary to ensure that payroll costs properly billed to the joint
16 partners are not included in the KCPL payroll costs. The level of payroll billed by KCPL to its
17 joint owners in the Iatan and LaCygne generating stations was based upon the March 31, 2012,
18 update period total. Staff used the Company methodology to correctly allocate the reduction in
19 payroll costs from the billing of joint partners, and these costs were removed net of the
20 L&P portion of Iatan before the allocation of payroll to KCPL and GMO. The other payroll costs
21 for partners are billed to The Empire District Electric Company, and the other partners in
22 the Iatan units, and to Westar Energy Company, the 50% partner in the two LaCygne
23 generating facilities.

24 The total annualized GPE and KCPL payroll costs allocated to KCPL also have to be
25 assigned between operational and maintenance ("O&M") expense and other expense. Typically
26 the other expense amount relates to construction and other non-expense functions of a company.
27 The construction amounts are assigned to the work orders for construction projects. The amounts
28 that are included in the revenue requirement calculations for KCPL are the levels assigned to
29 payroll expenses through the O&M expense ratios.

30 After the allocation between expense and construction, based on a five-year average
31 expense factor, Staff distributed the adjustment for payroll by individual FERC account based

1 upon the actual distribution for each of those accounts for the update period ending
2 March 31, 2012. Adjustments E-4.1, E-7.1, E-19.1, E-22.1, E-25.1, E-26.1, E-41.1, E-44.1,
3 E-48.2, E-52.1, E-57.1, E-62.1, E-63.1, E-64.1, E-65.1, E-76.1, E-77.1, E-78.1, E-81.1, E-82.1,
4 E-93.1, E-94.1, E-99.1, E-100.1, E-101.1, E-105.1, E-106.2, E-107.1, E-108.1, E-116.1, E-117.2,
5 E-122.1, E-123.1, E-124.1, E-125.1, E-128.1, E-134.2, E-135.2, E-136.2, E-138.2, E-144.1,
6 E-145.1, E-146.1, E-147.1, E-148.1, E-149.1, E-150.1, E-151.1, E-152.2, E-156.2, E-157.2,
7 E-158.3, E-159.2, E-160.2, E-161.2, E-162.2, E-163.2, E-164.2, E-168.1, E-169.1, E-170.1,
8 E-174.3, E-177.1, E-178.1, E-183.1, E-185.2, E-189.1, E-190.1, E-192.1, E-196.4, E-199.5,
9 E-202.1, E-208.2, E-209.2, E-218.5, E-219.1, E-220.1, E-222.1, E-223.1, E-225.1, E-227.3 and
10 E-234.1.

11 *Staff Expert/Witness: Bret G. Prenger*

12 **2. Payroll Related Benefits**

13 Staff's annualized 401k expenses were calculated based upon the test year percentage
14 match for KCPL applied to its share of total annualized payroll. In addition, the joint partner
15 share of KCPL 401k expenses was removed from the annual leave similar to the annualized
16 payroll adjustment.

17 Medical costs were and other employee benefits, located in account 926, were calculated
18 based upon twelve months ending March 31, 2012. Other Benefits include items such as
19 Educational Assistance and Recreational Activities. Adjustments E-210.1 E-210.2 and E-210.3
20 to the Income Statement reflect the calculated payroll related benefits based on payroll costs as
21 of March 31, 2012.

22 *Staff Expert/Witness: Bret G. Prenger*

23 **3. Payroll Taxes**

24 Payroll taxes were annualized by applying current payroll tax rates to each employee's
25 annual level of payroll. To compute payroll taxes for overtime, interns, premium pay, and
26 partner billings, an aggregate tax rate was applied based on the annualized payroll taxes for base
27 payroll. Wolf Creek payroll has a separate aggregate payroll tax rate applied based on test year
28 billed taxes. The payroll taxes follow the same allocation process used to allocate base payroll.

1 Adjustments E-258.1 and E-258.2 to the Income Statement reflect the annualized payroll taxes
2 based on payroll costs as of March 31, 2012.

3 *Staff Expert/Witness: Bret G. Prenger*

4 **4. True-up of Payroll Costs**

5 Staff will update the total payroll costs for the true-up in this case, which is based on an
6 update period of August 31, 2012. The same methodology used to annualize payroll as of
7 March 31, 2012 will be used for the August 31, 2012 true-up.

8 *Staff Expert/Witness: Bret G. Prenger*

9 **5. FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset**

10 The Commission Staff and KCPL entered into a Stipulation and Agreement in Case No.
11 ER-2010-0355 (2010 rate case) titled, “Nonunanimous Stipulation and Agreement Regarding
12 Pensions and Other Post Employment Benefits,” (Case No. ER-2010-0355 Pension and OPEB
13 Stipulation). The Case No. ER-2010-0355 Pension and OPEB Stipulation addressed the
14 ratemaking treatment for annual pension costs under Financial Accounting Standard No. 87
15 (FAS 87), and pension settlement and curtailment accounting under Financial Accounting
16 Standard No. 88 (FAS 88).

17 The names of the Financial Accounting Standards (FAS) have recently changed. The
18 Financial Accounting Standards Board’s Accounting Standards Codification project was
19 launched in 2009 and became the single source of authoritative nongovernmental U.S. GAAP
20 (other than guidance issued by the Securities and Exchange Commission). The new Codification
21 Topic 715 covers all of the following FASB statements under its various subtopics:-

- 22 • FAS 87 and FAS 88, Employer's Accounting for Pensions,
- 23 • FAS 158, Employers’ Accounting for Defined Benefit Pension and Other
24 Postretirement Plans
- 25 • FAS 106, Employers' Accounting for Post Retirement Benefits other than
26 Pension.

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

1 The Case No. ER-2010-0355 Pension and OPEB Stipulation reaffirmed the agreement
2 regarding these matters reached in KCPL's Regulatory Plan, and clarified the accounting for
3 pension cost allocated to KCPL's joint partners in the Iatan and LaCygne generating stations.
4 The Case No. ER-2010-0355 Pension and OPEB Stipulation also addressed the ratemaking
5 treatment for a curtailment or settlement recognized under FAS 88.

6 There are two amounts in rate base resulting from the Stipulation and Agreements in
7 Case Nos. EO-2005-0329, ER-2006-0314, ER-2007-0291, ER-2009-0089 and ER-2010-0355:

8 1) A Prepaid Pension Asset – The prepaid pension asset represents
9 the unrecovered balance of negative pension cost flowed back to ratepayers in
10 prior years.

11 2) An FAS 87 Regulatory Asset – Under the terms of the Stipulation
12 and Agreements referenced above, the difference between FAS 87 reflected in
13 rates and KCPL's actual cost recorded in its financial statements is tracked and
14 recorded as either a regulatory asset or liability, and is then amortized over five
15 years in the next rate case. KCPL's rate base includes a regulatory asset as of
16 March 31, 2011.

17 The Staff's annualized level of pension expense was based on information provided by
18 KCPL's actuarial firm, Towers Watson, to KCPL and provided to Staff in response to Staff Data
19 Request No. 246S. The Staff's pension calculation was made in accordance with the
20 methodology described in the Case No. ER-2010-0355 Pension and OPEB Stipulation.

21 KCPL is proposing cost of service recovery of \$11.2 million (KCPL share) in FAS 88
22 charges through a five year amortization increase to pension expense. This FAS 88 charge is
23 related to KCPL's employee termination program referred to as the Organizational Realignment
24 and Voluntary Separation (ORVS) Program. Based on the language related to FAS 88 in the
25 Case No. ER-2010-0355 Pension and OPEB Stipulation, Staff is not proposing any adjustment to
26 the level of FAS 88 costs proposed by KCPL.

27 The FAS 88 charge is related to the impact on pension expense of these employees being
28 removed from KCPL's management pension plan and the impact of paying lump sum pension
29 distributions. While the FAS 88 charge is an increase to cost of service, the ongoing level of
30 pension expense should be lower due to the removal of the costs of 140 management employees
31 from the pension plan. The Staff is still engaged in discovery to verify the level of pension
32 expense sought by KCPL in this case has been decreased by an appropriate amount by the
33 removal of these 140 management employees. The Staff will continue to have discussions with

1 KCPL on this matter and will make its final pension cost rate recommendation in its true-up
2 audit filing after it is convinced that all of the impacts of the ORVS Program have been reflected
3 in KCPL's costs included in cost of service in this case.

4 There are a number of assumptions built into Towers Watson's quantification of KCPL's
5 pension expense that were supplied to it by KCPL. One of these assumptions is KCPL's
6 projected level of future annual salary increases. The salary increase assumption is important
7 because KCPL's current level of pension expense is based in part on a projection of future salary
8 levels for its employees. A higher salary increase assumption will lead to a higher pension
9 liability and a higher pension expense. Based on discussions with KCPL personnel, the Staff
10 understands that the annual salary increase assumption used by KCPL for KCPL's current
11 projected pension expense is 4.0%. The Staff has concerns that given the economic environment
12 over the past three years and continuing into the foreseeable future, this assumption actually
13 overstates the level of pension expense that should be reflected in this rate case. Based on a
14 review of the current salary increase assumptions used by other regulated utilities in Missouri,
15 the Staff's concerns were confirmed.

16 The Staff reviewed the most recent annual reports of all major Missouri regulated utilities
17 and noted that KCPL's salary assumption rate of 4 percent is the highest of all Missouri utilities
18 and significantly higher than the all-Missouri utility average of 3.25 percent. The utilities
19 reviewed were AmerenUE, The Empire District Electric Company (Empire), Laclede Gas
20 Company (Laclede), American Water Works Company, Inc. ("American Water" - parent
21 company of Missouri-American Water Company) and Southern Union Company (parent
22 company of Missouri Gas Energy). The results of Staff's analysis are summarized below:

23	Company	Salary increase assumption (%)
24	Laclede	3.00
25	Southern Union Company	3.02
26	American Water	3.25
27	AmerenUE	3.50
28	Empire	3.50
29		
30	Average	3.25
31	KCPL	4.00

32 KCPL's selection of a 4.0% salary increase assumption is the highest of all major
33 regulated utilities in Missouri. To reflect the impact on pension expense of a salary increase

1 assumption more in line with other Missouri utilities, the Staff adjusted KCPL's annualized
2 pension expense by reflecting a 3.5% in lieu of a 4% salary increase assumption in Staff
3 Adjustment E-209. The numerical support for the amount of the adjustment was provided by
4 KCPL's actuaries in response to Staff Data Request No. 246S.

5 *Staff Expert/Witness: Charles R. Hyneman*

6 **6. FAS 106 – Other Postretirement Benefit Costs (OPEBs) and OPEB**
7 **Tracker Regulatory Liability**

8 Other Postretirement Benefit Costs ("OPEBs") are those costs incurred by the Company
9 to provide certain benefits to Company retirees. The primary benefit to retirees is medical
10 insurance but also includes life, dental and vision insurance benefits. Historically OPEB costs
11 have been calculated by KCPL's actuaries under the terms of Financial Accounting Standard 106
12 (FAS 106). Recently, ASC 715, the Accounting Standards Codification Topic, Compensation-
13 Retirement Benefits, superseded FAS 87, FAS 106, FAS 132 and FAS 158. ASC 715 reflects
14 current generally accepted accounting principles (GAAP) which outlines the standards of
15 financial accounting and reporting for employers that offer pension and other postretirement
16 benefits to employees. For purposes of clarity and continuity with the ratemaking treatment
17 afforded KCPL's OPEB costs over the years, in this testimony I will use the term FAS 106
18 synonymously with the term ASC 715 as they both encompass the same accrual accounting
19 methods for determining OPEB expense.

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

27 FAS 106 was not developed with the rate-setting process in mind, but created by the
28 FASB for the users of a company's financial statements. The FASB notes in its own description
29 of FAS 106 on its website "recognition and measurement of the accrued obligation to provide

1 postretirement benefits will provide users of financial statements with the opportunity to assess
2 the financial consequences of employers' compensation decisions.”

3 House Bill 1405 (Section 386.315 RSMo), approved by the Missouri Legislature and
4 signed into law by the Governor in 1994, required the adoption of FAS 106 for setting rates for
5 OPEB costs. In Commission cases following the date that House Bill 1405 became law, the Staff
6 began recommending the use of FAS 106 for determining ratemaking recovery for OPEB costs.
7 Prior to the effective date of Section 386.315 RSMo, rates were set on a “pay-as-you-go” or
8 “cash” basis for OPEB costs. Under the pay-as-you-go approach, the utility’s actual paid claims
9 for OPEB cost for current retirees were included for recovery for ratemaking purposes.

10 Section 386.315 RSMo includes a funding requirement as a prerequisite for the adoption
11 of FAS 106 for ratemaking purposes. The recognition of FAS 106 for ratemaking purposes is
12 conditioned on a requirement that annual FAS 106 costs collected in rates be funded in a separate
13 funding mechanism to be used solely for the payment of OPEB benefit costs to retirees.
14 Paragraph 2 of Section 386.315 addresses the funding requirement:

15 2. A public utility which uses Financial Accounting Standard 106 shall be
16 required to use an independent external funding mechanism that restricts
17 disbursements only for qualified retiree benefits. In no event shall any
18 funds remaining in such funding mechanism revert to the utility after all
19 qualified benefits have been paid; rather, the funding mechanism shall
20 include terms which require all funds to be used for employee or retiree
21 benefits. This section shall not in any manner be construed to limit the
22 authority of the commission to set rates for any service rendered or to be
23 rendered that are just and reasonable pursuant to sections 392.240,
24 393.140 and 393.150.

25 KCPL’s total OPEB expense includes costs associated with three separate and distinct
26 OPEB plans. Two of the plans are owned and controlled by KCPL and one is not. KCPL has a
27 Management OPEB plan and a Union OPEB plan. In addition, KCPL is a part owner of the
28 Wolf Creek Nuclear Operating Company (WCNOC).

29 WCNOC is owned by three owners: KCPL (47 percent ownership share), Westar Energy
30 Company (47 percent) and Kansas Electric Power Cooperative (6 percent). WCNOC manages
31 the nuclear Wolf Creek Generating Station for its owners, who share its energy in proportion
32 to their ownership interest. As a part owner, KCPL is required to reimburse WCNOC for
33 the costs it incurs to operate the nuclear power plant. On a recurring basis WCNOC bills KCPL

1 for KCPL's share of fuel, and other operating and maintenance costs, including pension and
2 OPEB costs.

3 During the Staff's rate case audit of KCPL's OPEB expense and its review of KCPL's
4 FAS 106 actuarial reports, the Staff discovered that the FAS 106 calculation for WCNOG's
5 OPEB expense did not include an "expected return on plan assets" component as required if the
6 amounts are externally funded. All pension and OPEB funds that actually have a fund to which
7 dollars are contributed have an investment manager who invests those dollars in the fund into a
8 portfolio of market investments such as stocks, bonds, and other investments. The annual
9 expected financial return on these investments are included as an offset or credit to the other
10 components of the FAS 106 accrual (which are primarily the future OPEB benefits earned in the
11 current period and the estimated time value of money cost until the benefits are paid). This
12 expected return on plan assets component of FAS 106 normally results in a significant reduction
13 to the current FAS 106 accrual.

14 In discussions with KCPL on this matter it appears that Staff and KCPL did not have the
15 same level of understanding as to the requirement to fund the level of Wolf Creek OPEB costs
16 included in rates. Based on discussions with KCPL it was determined that although KCPL has
17 been recovering WCNOG OPEB expenses in rates using the FAS 106 accrual method, KCPL
18 was being billed by and paying WCNOG OPEB costs on a pay-as-you go basis. Historically,
19 annual OPEB calculated under FAS 106 have exceeded, to a significant extent, annual pay-as-
20 you-go OPEB amounts. While the Staff still has outstanding discovery requests on this issue, it
21 does have sufficient information to conclude that it is likely KCPL has been significantly over-
22 collecting its WCNOG OPEB costs for several years.

23 KCPL has verbally advised the Staff that the excess of FAS 106 WCNOG OPEB costs
24 collected in Missouri rates over the amount of KCPL's payments to WCNOG on a pay-as-you-go
25 basis has been contributed to KCPL's OPEB trust funds for its own employees. Because
26 KCPL's WCNOG costs are not billed to KCPL based on the FAS 106 accrual method but instead
27 are billed on a pay-as-you-go basis, it is inappropriate to include in rates a level of WCNOG
28 OPEB expense based on the FAS 106 accrual accounting method. Instead, OPEB costs for
29 WCNOG should match the manner in which KCPL is billed by and pays WCNOG for these
30 expenses. Therefore, while the Staff uses the FAS 106 methodology to calculate OPEB costs for
31 KCPL's Management OPEB plan and KCPL's Union OPEB plan (as these plans have funds

1 established and KCPL actually contributes to these funds the level of OPEB costs included in
2 rates), for the WCNOB plan, the Staff included the level of OPEB expenses KCPL actually paid
3 WCNOB in 2011.

4 Staff has not yet determined the appropriate treatment for potential significant past
5 WCNOB OPEB over collections. As discussed previously, KCPL has indicated that it has
6 included the excess of amounts collected in rates for WCNOB OPEBs over what it paid
7 WCNOB in its own KCPL-owned OPEB plan funds. If this proves to be the case, then these
8 funds may be available to offset against future WCNOB OPEB charges. The Staff will meet
9 with KCPL and discuss this issue. Lacking resolution, the Staff will address the issue of past
10 excess funding for KCPL employee OPEBs in later testimony filings in this case.

11 The Staff's OPEB adjustment to KCPL Account 926, Employee Benefits annualizes the
12 level of OPEB expense determined by KCPL's actuaries using the FAS 106 accounting method,
13 with the exception of WCNOB OPEB costs as described above. If more current OPEB actuarial
14 reports for KCPL's Management and Union OPEB plan are completed prior to the end of the
15 true-up period in this case, Staff will update its OPEB expense annualization accordingly. Staff
16 Adjustments E-210 and E-211 adjusts KCPL's September 2011 ending test year per book costs
17 for FAS 106 to reflect the more current FAS 106 actuarial calculation for 2012.

18 Beginning May 4, 2011, KCPL initiated a new tracker for OPEB costs authorized by the
19 Commission in Case No. ER-2010-0355. The dollars tracked are the difference between the
20 current ongoing level of OPEB expense and the dollar amount of OPEB expense reflected in
21 rates in each case. The unamortized balance of this tracker will be amortized over five years in
22 each successive rate case and either added to or subtracted from the level of OPEB expense as
23 determined by KCPL's actuaries. As noted by KCPL in its direct filing in this case, because
24 OPEB costs decreased from the amount included in rates in Case No. ER-2010-0355, a
25 regulatory liability was created and the Missouri jurisdictional portion of this regulatory liability
26 is reflected as a reduction of rate base in the Staff's Accounting Schedules. As with other rate
27 base prepaid pension and other pension assets, it is anticipated that the OPEB tracker liability
28 will be updated through the August 31, 2012 true-up period.

29 As noted in the Nonunanimous Stipulation and Agreement Regarding Pensions and Other
30 Post Employment Benefits to Case No. ER-2010-0355, the Signatories are not bound to propose
31 continuation of the ratemaking treatment afforded pensions and OPEBs outlined in the

1 Stipulation and Agreement in future rate cases, such as the current rate case. For the purposes of
2 this rate case, the Staff has decided to continue with the treatment outlined in the Stipulation and
3 Agreement for OPEB and will decide in KCPL's next rate case whether or not changes or
4 adjustments to this methodology are appropriate.

5 *Staff Expert/Witness: Charles R. Hyneman*

6 **7. Supplemental Executive Retirement Plan (SERP) Expense**

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

18 For the first quarter of 2012, KCPL's monthly cash SERP annuity payments were
19 \$15,651. The Staff annualized this amount to \$187,812 and multiplied this annualized amount
20 by the KCPL allocation factor of 69.1% for a net KCPL SERP amount of \$129,778 which is
21 included in Staff's revenue requirement recommendation as adjustment E-209 to Account 926,
22 Employee Benefits.

23 *Staff Expert/Witness: Charles R. Hyneman*

24 **8. Talent Assessment Amortization**

25 In Case No. ER-2007-0291, KCPL proposed the recovery in rates of what it referred to as
26 "Talent Assessment" or "Skill Set Realignment" costs. These costs were primarily severance
27 payments to either employees whose employment was terminated by KCPL or employees who
28 elected to leave KCPL. The total cost of the severance program, according to KCPL, was
29 approximately \$9.6 million for the termination of 119 KCPL employees. The Missouri

1 jurisdictional portion of those costs, as allocated by KCPL, was \$4,840,517. The Commission
2 concluded that the Talent Assessment severance costs should be recognized in cost of service,
3 and authorized the amortization to expense over five (5) years commencing January 2007.
4 KCPL's 12 months ending September 2011 test year income statement includes \$968,103 as an
5 amortization to expense for this cost in account 920. KCPL started the five year amortization of
6 this deferral in rates in January 2008 and the amortization ends, and the program costs will be
7 completely recovered in rates, in December 2012.

8 Staff consistently has opposed recovery of the Talent Assessment Program costs in
9 KCPL's previous rate cases. It is common for Staff to assess the value of the assets on a utility's
10 balance sheet, especially intangible assets such as regulatory assets, to ensure the costs that
11 formed the basis of the assets have in fact created actual benefits to the utility and its customers.
12 In KCPL's last rate case, Case No. ER-2010-0355, Staff did a review to determine if any of the
13 benefits KCPL hoped to achieve from the Talent Assessment Program actually materialized.
14 Staff found that they had not. In that case, this issue was among several issues settled by the
15 *Non-Unanimous Stipulation and Agreement as to Miscellaneous Issues* filed on or about
16 February 3, 2011. By the time new rates from this case are anticipated to be in effect (i.e.,
17 February 2013), KCPL will have directly recovered through rates approximately one hundred
18 and two (102) percent of the \$4,840,517 million Talent Assessment deferral or
19 \$4,921,192 million, for an over-collection through regulatory lag of \$80,675. Consistent with its
20 position on this issue in KPCL's prior rate cases, Staff has not included this amortization when
21 determining KCPL's revenue requirement for this case.

22 Staff's Adjustment E-197 in this case removes this amortization from KCPL's cost of
23 service.

24 *Staff Expert/Witness: Charles R. Hyneman*

25 **9. March 2010 Organizational Realignment/Voluntary Separation**
26 **(ORVS) Program**

27 KCPL launched its Organizational Realignment/Voluntary Separation Program (ORVS)
28 on March 10, 2011. Under this voluntary separation program, any KCPL non-union employee
29 could voluntarily elect to separate from KCPL and receive a severance payment equal to two

1 weeks of salary for every year of employment, with a minimum severance payment equal to
2 fourteen weeks of salary.

3 There were 140 KCPL employees that made such elections, and the majority separated
4 from KCPL on April 30, 2011. KCPL recorded an expense of \$12.7 million related to this
5 voluntary separation program, reflecting severance benefits and related payroll taxes provided by
6 KCPL to employees who elected to voluntarily separate from KCPL.

7 At page 94 of KCPL's 2011 SEC Form 10-K, KCPL stated that the savings from the
8 realignment process and voluntary separation program included \$15 million in labor costs on an
9 annual basis. Staff did an analysis of the net costs of the ORVS program (including KCPL's FAS
10 88 costs) and the net savings realized through regulatory lag. Staff's analysis shows that KCPL
11 recovered all of its ORVS-related costs and realized a net savings of approximately \$13 million
12 (total savings allocated on a KCPL jurisdictional basis). The Staff's analysis was based on actual
13 data provided by KCPL, including employee salaries and current benefit-salary ratios

14 In its response to Staff Data Request No. 119, KCPL recognized that it will recover in
15 rates in just one year more than the total cost of the ORVS Program through regulatory lag as
16 follows:

17 As seen in the attachment, the total of the annual salaries of the employees
18 electing the program was over \$12.5 million. If we applied a conservative
19 benefits loading rate of 40%, the annual savings from the terminating
20 employees would reach \$17.5 million. With the total cost of the program
21 near \$13 million, the Company should begin to achieve savings in the first
22 quarter of 2012.

23 Regulatory lag is a naturally occurring phenomenon in cost of service regulation. It
24 refers to the period of time between when a cost or revenue changes and the time that change is
25 reflected in rates.

26 Staff made the same adjustment as KCPL to remove the test year amount of KCPL's
27 ORVS severance program cost from KCPL's revenue requirement in Staff Adjustments E-196,
28 E-199 and E-258; however, since these employee severance costs have been recovered in rates,
29 Staff is not recognizing this ORVS cost as a deferral and is not reflecting any amortization of this
30 cost in its KCPL revenue requirement recommendation. It is inappropriate ratemaking theory to
31 defer a cost that has already been directly recovered in utility rates.

32 FAS 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit*
33 *Pension Plans and for Termination Benefits*, (now classified as part of ASC 715, Compensation-

1 Retirement Benefits) addresses the accounting for settlements and curtailments related to pension
2 benefits. As noted above, the Staff performed an analysis of the level of savings enjoyed by
3 KCPL by continuing to recover all ORVS-related costs in rates from April 30, 2011 through
4 February 2, 2013 (the date when rates from this case will take effect). Staff's analysis confirmed
5 that KCPL will recover all of its ORVS-related costs, including all FAS 88 costs, through
6 regulatory lag and still receive substantial savings. However, based on the language of the
7 *Nonunanimous Stipulation and Agreement Regarding Pensions and Other Post Employment*
8 *Benefits* in Case No. ER-2010-0355 (*2010 Pensions/OPEBs Stipulation*), Staff is including
9 KCPL's ORVS FAS 88 charges in Staff's pension expense for KCPL's cost of service and
10 revenue requirement in the manner prescribed in the *2010 Pensions/OPEBs Stipulation*. As
11 described above, KCPL has more than fully recovered all of its ORVS Program severance
12 payments and none of these severance payments should be included in KCPL's cost of service or
13 revenue requirement in this case.

14 *Staff Expert/Witness: Charles R. Hyneman*

15 **10. Correction of Accounting for KCPL's Iatan 2 Construction bonus**
16 **payments**

17 In 2010 and 2011, KCPL recorded employee bonuses related to the construction of
18 Iatan 2 in the amount of \$850,764 (Staff Data Request No. 257). Staff is not proposing any
19 disallowances of these bonuses in this case. Staff's position is based on its understanding of the
20 Commission's *Report and Order* in Case No. ER-2010-0355 as it relates generally to Iatan 2 cost
21 overrun issues. Based on discussions with KCPL personnel Staff understands that KCPL
22 incorrectly booked \$103,356 of the \$850,764 in bonuses to expense accounts instead of
23 capitalizing them to plant in service. KCPL advised Staff that it would correct its books and
24 records to remove this \$103,356 from its expense accounts. Staff Adjustments E-4, E-19, and
25 E-38 correct KCPL's test year expense accounts by removing these bonuses. Staff is not
26 including the \$103,356 Iatan 2 bonus payments in plant in service as it does not have the plant
27 account distribution to make this adjustment. Staff assumes that KCPL will propose to include
28 these bonus payments in its true-up recommendation in this case. If so, Staff will review the
29 adjustment at that time.

30 *Staff Expert/Witness: Charles R. Hyneman*

1 **11. Short Term Annual Incentive Compensation**

2 KCPL has three separate, short term annual incentive compensation plans for executive,
3 management, and union employees. These plans are designed to grant cash awards of various
4 amounts calculated based upon designated annual metrics. The timing of the payout for amounts
5 accrued under the terms of each plan for a calendar year is during the first quarter of the
6 following calendar year. The three incentive compensation plans are: 1) the Rewards Plan,
7 reserved for bargaining-unit (union) employees; 2) the Value-Link Plan, reserved for
8 management-level KCPL employees; and 3) the Annual Executive Incentive Plan, reserved for
9 senior KCPL management employees.

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

14 The Rewards Plan was implemented to reward bargaining-unit employees for their efforts
15 in supporting the objectives of the Company. The purpose of the plan is to provide an incentive
16 for the achievement of defined annual results of KCPL and its divisions (Accounting,
17 Regulatory, Finance, Human Resources etc.). The plan covers bargaining-unit employees from
18 the International Brotherhood of Electrical Workers ("IBEW") Local 1464 (approximately
19 659 employees), Local 412 (approximately 847 employees), and Local 1613 (approximately
20 420 part/full time employees). ** _____
21 _____
22 _____
23 _____
24 _____
25 _____
26 _____
27 _____
28 _____
29 _____
30 _____
31 _____

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

**

Staff does not oppose incentive compensation paid under the Rewards Plan, as the KCPL Rewards Plan scorecard goals include customer metrics and are primarily customer focused. The Rewards Plan is not the result of a collective bargaining agreement. If it were the result of a collective bargaining agreement, then it is my understanding that pursuant to Section 386.315.1 RSMo., in establishing public utility rates, the Commission is prohibited from reducing or otherwise changing any wage rate, working condition, or other term or condition of employment that is the subject of a collective bargaining agreement between a public utility and a labor organization.

The Value-Link Plan was implemented to provide an incentive for the achievement of defined annual results of the Company and its business units by management-level KCPL employees, such as Plant Manager or Insurance Manager. **

1 Value-Link Plan, Staff is not proposing to exclude amounts actually paid out under the
2 Value-Link Plan established by the revised plan.

3 The third short term annual incentive plan is the Annual Executive Incentive Plan
4 (“Executive Plan”), which is designed to motivate and reward senior management to achieve
5 specific key financial and business goals and to also reward individual performance of senior
6 GPE and KCPL management. ** _____

7 _____
8 _____
9 _____
10 _____
11 _____
12 _____
13 _____
14 _____
15 _____
16 _____
17 _____

18 _____ **
19 Adjustments E-4.2, E-122.2, E-144.2, E-147.2, E-152.3, E-168.2, E-185.3 and E-196.5.

20 *Staff Expert/Witness: Bret G. Prenger*

21 **12. Long-Term Incentive Compensation**

22 According to GPE, the purpose of the GPE Long-Term Incentive Plan is to encourage
23 officers and other key employees to acquire a proprietary and vested interest in the growth and
24 performance of GPE; to generate an increased incentive to enhance the value of the Company for
25 the benefit of its customers and shareholders; and to aid in the attraction and retention of the
26 qualified individuals upon whom the Company’s success largely depends. ** _____

27 _____
28 _____
29 _____

30 _____ **



1 KCPL proposed to eliminate the Long-Term Incentive Compensation Plan for its
2 officers in Case ER-2012-0174 via Company adjustment CS-11. The Staff agrees with this
3 proposal, and has also made the adjustment to remove the Long-Term Incentive Compensation
4 Plan from the case.

5 *Staff Expert/Witness: Bret G. Prenger*

6 **C. Maintenance Normalization Adjustments**

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

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

24 Staff analyzed maintenance costs from 1999 through March 31, 2012, by functional area
25 for production, transmission, distribution, and general plant by FERC account. Staff separated
26 maintenance between labor and non-labor costs. Since labor costs are specifically addressed as a
27 component in the cost of service analysis, labor costs were segregated from the non-labor costs
28 to perform the review of maintenance costs. Staff annualized payroll reflecting the price
29 increases for labor that generally occur each year. A detailed staff position related to payroll is
30 located under the heading *Payroll, Payroll Related Benefits* in this report. The maintenance
31 analysis was done only on non-wage maintenance and operating costs.

1 Several steps were taken to analyze the maintenance data. They included examining the
 2 non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as
 3 trends or fluctuations from one period to another. Another approach used by the Staff, was to
 4 compare functional averages which included using a two (2)-year average through a seven (7)-
 5 year average to determine if there were fluctuations with each functional area. Staff also
 6 analyzed Production maintenance excluding Iatan 2 production maintenance. The purpose of
 7 excluding Iatan 2 production maintenance costs is to identify if production maintenance
 8 fluctuated absent these costs. After isolating Iatan 2 production maintenance Staff determined
 9 production maintenance remained relatively consistent for the calendar years 2010 and 2011
 10 absent Iatan 2 production costs. Staff performs a separate analysis for Iatan 2 production
 11 maintenance. A discussion for Iatan 2 production maintenance is located under the heading
 12 *Iatan 2 O&M Expenses* in this report. Each of the costs by year and averages for maintenance
 13 were also compared to the Test Year, 12-month period ended September 30, 2011. Staff
 14 reviewed the data as detailed above to establish a maintenance level that will result in an annual
 15 level of the Company's future maintenance costs.

16 Staff's results are presented in the following table:
 17

Results of Staff's Non-Labor Maintenance Analysis	
Steam Production Maintenance	Test Year 12-Month Ended September 30, 2011
Nuclear Production Maintenance	2-year average (2010-2011)
Other Production Maintenance	Test Year 12-Month Ended September 30, 2011
Transmission Maintenance	2-year average (2010-2011)
Distribution Maintenance	3-year average (2009-2011)
General Maintenance	Test Year 12-Month Ended September 30, 2011

18
 19 As identified in the table above, Staff made a decision to use the 12-month period ended
 20 September 30, 2011 test year account balances to represent future maintenance costs for
 21 Production, Nuclear, Other Production and General Maintenance. Staff used the 12-month
 22 period ended September 30, 2011 test year to reflect a level of normalized maintenance for these

1 costs based on actual information provided by KCPL for a period of several years. This
2 historical information was analyzed to determine the proper level of maintenance which should
3 be included in this case. Fluctuations occurred each year for Nuclear Transmission and
4 Distribution Maintenance. Consequently, a two (2)-year average of Nuclear and Distribution
5 Maintenance and a three (3)-year average of Transmission Maintenance reflects a normal level
6 of maintenance expense that should be included in KCPL's cost of service.

7 For Wolf Creek, there are two types of O&M costs – 1. O&M for general plant and 2.
8 O&M relating to the refueling outages that occur every 18 months. Staff performs a separate
9 analysis for nuclear refueling outages. A discussion for Wolf Creek's refueling is located under
10 the heading *Wolf Creek Nuclear Refueling Outage* in this report. The adjustment for Wolf Creek
11 non-refueling Maintenance are E-76.2, E-77.2, E-78.2, E-81.2, E-82.2. The adjustments for
12 Transmission Maintenance are E-133.1, E-134.1, E-135.1, E-136.1, E-137.1 and E-138.1.
13 The adjustments for Distribution Maintenance are E-156.1, E-157.1, E-158.1, E-159.1, E-160.1,
14 E-161.1, E-162.1, E-163.1 and E-164.1.

15 *Staff Expert/Witness: Karen Lyons*

16 **1. Wolf Creek Nuclear Refueling Outage**

17 Staff included an annualized level of refueling costs, amortization of non-routine
18 refueling costs, and an amortization based on the Stipulation and Agreement in Case No.
19 ER-2009-0089. Staff reviewed information provided by KCPL for the last six nuclear refueling
20 outages. Refueling costs have increased over the last three refuelings—refueling outage #16,
21 #17 and #18. During Staff's investigation of the increased refueling costs, Staff determined the
22 age of the plant and unplanned equipment issues led to the increased costs. KCPL responded to
23 data request 147.2⁷³ as follows:

24 **
25
26
27
28
29
30
31

⁷³ Case No. ER-2012-0174

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32

**

The costs associated with the Wolf Creek refueling outage are deferred and amortized over an 18-month period. In this case, refueling costs booked in the test year reflect costs associated with refueling #17 and #18. Both Staff and KCPL annualized the most current refueling #18 to ensure the level of expense included in KCPL's cost of service reflects the costs entirely related to refueling #18.

KCPL identified routine and non-routine maintenance costs that occurred during the refueling #18. As previously discussed KCPL experienced increased costs for this refueling due to unplanned equipment issues. As a result, KCPL proposed to amortize the excess non-routine costs over a five (5)-year period. This proposal is similar to how excess costs for refueling #16 were treated in Case No ER-2009-0089 which is discussed later in this section of this report. Although Staff agrees with KCPL's treatment of amortizing the non-routine costs, Staff recommends the inclusion of additional non-routine costs in the amortization. During Staff's analysis of refueling #18 and through discussions with KCPL, KCPL identified additional non-routine costs that were not included in its amortization proposal. Staff recommends including the non-routine refueling costs and the additional non-routine costs identified during the audit and amortizing these costs over a five year period.

Based on the discussion above, Staff included an annualized level of refueling costs based on the most current refueling outage #18 less the non-routine costs that occurred during the outage. Staff also included one-fifth of the total non-routine costs. The adjustments for refueling #18 and amortization of non-routine refueling costs are reflected in Staff's Accounting Schedule 9, Adjustment E-71.1 and E-79.1 respectively.

In addition to the adjustments mentioned above, Staff made an adjustment for the refueling amortization established in the Stipulation Agreement in Case No. ER-2009-0089. KCPL deferred and amortized the actual cost incurred during the Wolf Creek refueling outage over 18 months (the time period between refueling outages). The outage periods for the 2003 refueling #13 was 45 days; the outage period for the 2005 refueling #14 was 40 days and the outage period for the 2006 refueling #15 was 34 days. In contrast, the outage period for the 2008



1 refueling #16 was 55 days and the 2009 refueling #17 was 59 days. The average outage period
2 for the three refueling periods occurring in 2003, 2005, and 2006 was 40 days. The 2009
3 refueling that lasted 59 days represented an increase of 48 percent above the average refueling
4 outage days [average 40 days compared to 59 days]. Because of this abnormal event, the
5 refueling costs of the outage increased significantly. KCPL and other signatory parties agreed
6 through a Stipulation and Agreement in Case No ER-2009-0089 to defer the cost of Outage #16
7 O&M refueling over a five year period. In the Non-Unanimous Stipulation and Agreement
8 (Agreement) issued in Case No. ER-2009-0089 the signatory parties agreed to the following:

9 The Signatory Parties agree that \$1,570,581 (Missouri jurisdictional) of
10 Outage #16 O & M refueling costs will be deferred in a regulatory asset
11 account and amortized over five years beginning with the date new rates
12 become effective in this case, with one-fifth of this cost included in cost of
13 service in this case. The unamortized balance will not be included in rate
14 base.⁷⁴

15 Subsequently, no party objected to the Agreement and the Commission approved the
16 Agreement in its June 10, 2009 *Order Approving Non-Unanimous Stipulations And Agreements*
17 *And Authorizing Tariff Filing.*

18 The deferral of the amortized refueling amount began on September 1, 2009, and will end
19 September 1, 2014. The test year amount recorded on KCPL's books reflects the appropriate
20 amortization level, therefore, no adjustment was necessary for this case.

21 *Staff Expert/Witness: Karen Lyons*

22 **2. Nuclear Decommissioning**

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

25 ...

26 3) Kansas City Power & Light Company's retail jurisdiction annual
27 decommissioning expense accruals and trust fund payments shall continue
28 at the current level of \$1,281,264.

29 4) The current decommissioning costs for Wolf Creek are included in
30 Kansas City Power & Light Company's current Missouri cost of service

⁷⁴ Case No. ER-2009-0089, *Non-Unanimous Stipulation And Agreement*, p. 7.

1 and are reflected in its current Missouri retail rates for ratemaking
2 purposes.⁷⁵

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

5 *Staff Expert/Witness: Karen Lyons*

6 **3. Iatan 2 O&M Expenses**

7 Staff included an annualized level of Iatan 2 O&M expenses and an amortization of
8 the costs in excess of the base amount established in Case No ER-2010-0355. In Case No ER-
9 2010-0355, Staff recommended a tracker for Iatan 2 O&M expense, so the actual cost of the
10 O&M expense related to Iatan 2 will be recovered through rates for both the rate payer and
11 KCPL in future rate cases. Since Iatan 2 was placed in service on August 26, 2010, and KCPL's
12 limited operational experience with Iatan 2 at the time of Case No ER-2010-0355, an O&M
13 tracker was suggested to protect both KCPL and its customers from including projected costs in
14 rates that will in all likelihood vary from the actual costs associated with Iatan 2's O&M
15 expense. KCPL and other signatory parties agreed through a Stipulation and Agreement in Case
16 No. ER-2010-0355 to establish a tracker for Iatan 2 costs and on April 12, 2011, the Commission
17 approved the use of a tracker for these costs.

18 In this case, Staff analyzed Iatan 2 O&M costs beginning August 26, 2010, through
19 April 2012. Staff included an annualized level of expense for Iatan 2 O&M for the 12 month
20 period of April 2012. KCPL advised Staff of an accounting error that occurred with the Iatan 2
21 and Common costs that was corrected in March 2012. Since the correction was made in March
22 2012, the update period in this case, Staff chose to include an annualized level of Iatan 2 costs
23 consisting of the 12-month period ended April 2012 and will examine these costs again for the
24 true up period of August 31, 2012. The annualized level of Iatan 2 O&M costs are reflected in
25 Accounting Schedule, Adjustments: E-4.3, E-5.1, E-19.2, E-20.1, E-22.2, E-23.1, E-25.2, E-26.2,
26 E-28.1, E-29.1, E-38.1, E-39.1, E-41.2, E-42.1, E-45.1, E-46.1, E-48.3, E-49.1, E-52.2, E-51.1,
27 E-199.8, E-200.1.

28 In addition to determining an ongoing level of Iatan 2 O&M expenses, Staff is
29 proposing the recovery of the excess costs over the base amount established in the Stipulation

⁷⁵ File No. EO-2012-0068, *Order Approving Stipulation And Agreement*, p. 3.

1 and Agreement in Case No ER-2010-0355. Staff is proposing a three (3)-year amortization of
2 the excess costs over the base amount. An adjustment reflecting one-third of the total costs is
3 reflected in Staff's Accounting Schedule 9, Adjustments E-5.2, E-20.2, E-23.2, E-26.3, E-29.2,
4 E-39.2, E-42.2, E-46.2, E-49.2, E-51.2, E-200.2.

5 As previously mentioned, Iatan 2 was placed in service on August 26, 2010. At the end
6 of the true up period in this case, August, 31, 2012, the plant will have operated for two (2)
7 years. Since the plant is still in its early stage of operation, two (2) years is not an adequate
8 period of time to recommend an annualized level of O&M expense for a new coal fired power
9 plant. Therefore, Staff recommends the continuation of the Iatan 2 tracker at the annualized
10 level discussed above.

11 *Staff Expert/Witness: Karen Lyons*

12 **D. Other Non-Labor Adjustments**

13 **1. Hawthorn 5 SCR**

14 In Case No. ER-2010-0355, the Commission established KCPL's level of rate base to
15 include the value of Hawthorn's 5 selective catalytic reduction system (SCR) at Babcock &
16 Wilcox's (B&W) original contracted performance standard. Due to the SCR's failure to the
17 meet the original contracted standard or the revised standard, rate payers will continue to pay
18 associated increased costs for the life of the SCR. In this case, Staff's adjustments of the
19 Hawthorn 5 SCR costs reduce plant operating costs including fuel related expenses associated
20 with early replacement of the SCR catalysts, reduce ammonia costs to the level of what KCPL
21 would have incurred if the SCR had met the original contracted performance standard, and adjust
22 the Hawthorn 5 forced outage rate for the period of 2005-2011, which includes excess outages
23 related to problems that occurred with the SCR. The adjustment to the outage rate reduces fuel
24 expense included in Staff's determination of KCPL's revenue requirement.

25 After the February 1999 explosion at KCPL's coal-fired Hawthorn 5 generating unit,
26 which entirely destroyed the boiler, B&W and KCPL entered into an engineering, procurement,
27 and construction agreement for the construction of Hawthorn Unit 5 boiler island ("B&W
28 Agreement"). The Agreement required B&W to install a selective SCR at Hawthorn Unit 5.
29 This environmental equipment was installed to reduce pollution associated with operating a coal-
30 fired generating unit. Under the Agreement, B&W guaranteed specific performance standards,

1 including an ammonia slip test. After the SCR was placed in service in 2001, the boiler failed
2 the ammonia slip test. The guaranteed performance standards were part of the contractual
3 agreement between B&W and KCPL that required KCPL to pay for the SCR.

4 During the period of 2002 through 2004, KCPL and B&W tried to resolve the SCR
5 performance issues by B&W doing additional work on the environmental equipment but was
6 unable to correct the SCR issues. B&W and KCPL entered into a Memorandum of
7 Understanding ("MOU"), and revised the ammonia slip test requirement to a lower standard.
8 Subsequently, B&W failed to meet these revised lowered standard. Because of B&W's failure to
9 meet the ammonia slip test standard on an ongoing basis, KCPL had to replace catalyst more
10 often, used more ammonia, increased Hawthorn's plant outages resulting in higher fuel costs and
11 incurred additional cleaning and maintenance expense. The excess outages increased KCPL's
12 fuel and purchased power expense. The increased capital costs, increased usage of ammonia,
13 increased cleaning and maintenance expense and increased fuel and purchased power expense
14 related to the excess outages all resulted in significantly higher than expected costs for KCPL to
15 run and maintain the Hawthorn 5 SCR.

16 After B&W was unable to achieve the lower revised standards, KCPL requested and in
17 2007 obtained liquidated damages based on the B&W boiler contract for the difference between
18 KCPL's costs if the contract performance standards were met and the actual costs KCPL will
19 actually incur to run the Hawthorn 5 SCR. The B&W settlement [Attached as Appendix 3,
20 Schedule KL-1] in essence recognized a lower performing piece of equipment, which will
21 require higher operating and maintenance costs over the life of the unit.

22 As a result of the defective SCR at Hawthorn 5 that was placed in service in 2001, KCPL
23 continues to incur excess costs to operate this unit and will continue to do so throughout the life
24 of the unit. Consequently, KCPL customers will continue to pay higher rates for KCPL's higher
25 costs for the increased frequency of replacing SCR catalysts, increased usage of ammonia,
26 increased cleaning and maintenance and related increased fuel expense related to abnormal
27 outages. All the higher operating costs have been and are currently included in rates paid by
28 KCPL's customers. In KCPL's last rate case, Case NO. ER-2010-0355, KCPL suggested in lieu
29 of treating the B&W settlement as a reduction to rate base, that Staff could make individual
30 adjustments for each of the components making up the unreasonable costs and increases in the

1 cost of service. Therefore, Staff is recommending adjustments to KCPL's rate base and fuel
2 expense for the performance deficiency of KCPL's Hawthorn 5 SCR in this rate case.

3 Based on the original B&W contract specifications, the SCR catalysts were designed to
4 operate for 24,000 hours or approximately 3 years without replacement. B&W was unable to
5 meet this specification; KCPL has to replace the catalysts approximately every 2 years. Since
6 the catalysts are replaced more frequently, KCPL customers are paying for more frequent
7 catalyst replacement, i.e., higher costs than those they would incur had B&W met the agreed
8 upon contract specifications for the catalysts life. KCPL accounts for the catalyst replacement
9 costs broken out between capital and O&M, depending on the number of catalysts that need to be
10 replaced. The following chart compares the date catalyst replacement should have occurred,
11 based on the original contract, and the date KCPL replaced catalysts (Capital and O&M) as a
12 result of a defective SCR, the costs for catalyst replacement (Capital and O&M) and identifies
13 who paid for the catalyst replacement (B&W, KCPL customers or KCPL shareholders).

14
15
16
17
18
19
20
21
22 *continued on next page*
23
24
25
26
27
28
29
30
31

1 in the table above for March 2012. KCPL has not transferred these costs to plant in service as of
2 March 31, 2012. Staff anticipates the costs will be transferred to plant in service for the true up
3 period ending August 31, 2012. As part of its true-up audit, Staff will review these costs and
4 recommend any necessary adjustment. Although the Company has experienced higher than
5 normal O&M expenses since the SCR was placed in service in 2001, Staff did not make any
6 adjustments to the O&M costs directly related to the SCR catalyst cleaning that occurred during
7 the test year ending September 30, 2011. This is because the catalyst cleaning occurred during a
8 normal maintenance outage. Staff would expect to see some level of catalyst cleaning during a
9 normal maintenance outage and therefore Staff did not make an adjustment for the SCR O&M
10 costs that occurred during the test year. Although Staff did not make an adjustment in this case
11 for the excess O&M costs, KCPL customers have paid for all of the excess O&M costs since
12 2004 and, unless disallowed, will continue to pay for these costs throughout the life of the plant.

13 As previously mentioned, KCPL customers have also paid for additional fuel, including
14 ammonia, purchased power and fuel costs as a result of excessive outages due to the SCR subpar
15 performance. Similar to all the increased costs associated with the defective SCR previously
16 mentioned, Staff did not make an adjustment to exclude any fuel expense in each of the last four
17 rate cases associated with the SCR, for various reasons (B&W had not yet accepted liability,
18 black box settlements and proposed plant adjustments). Thus, any increase in ammonia expense
19 incurred to operate the SCR at Hawthorn 5 has been included in both KCPL and Staff's
20 respective revenue requirements for KCPL in each of its last four rate cases. The following table
21 identifies this:⁸¹

22
23
24
25
26 *continued on next page*
27
28
29
30

⁸¹ Based on KCPL response to Data Request 146 in Case No. ER-2012-0174.

1 It is important to note that customers have also paid for increased purchased power costs
 2 by virtue of how Staff analyzes purchased power for rate making purposes. In each rate case, the
 3 Commission's Operations Division reviews purchased power costs along with Staff members
 4 assigned to the Auditing Department. Purchased power costs and levels are examined on a
 5 megawatt-hour basis for the test year and, typically, the update period. Staff includes a level of
 6 purchased power costs based on the actual purchases experienced during the time of each rate
 7 case. Consequently, in Case No. ER-2009-0089, the levels and amounts of purchased power
 8 were examined based on the 2007 test year time period through the September 30, 2008 update
 9 period. The 2007 test year is important because Hawthorn 5 had a significant outage for the SCR
 10 which occurred during the period of February 24, 2007 to March 9, 2007. The outage was
 11 necessary to replace the SCR catalysts after B&W was unable to meet the contract specifications
 12 after several attempts to do so. Since excess outages occurred during the test year of each of the
 13 last four rate cases, increased purchased power costs were included in each case. By virtue of
 14 the way purchased power is done in a rate case, Staff includes a level of purchased power costs
 15 based on the actual purchases experienced during the time of each rate case. The following table
 16 identifies the different test years used for each of the four rate cases KCPL filed since 2006:
 17

Case Number	Test Year	Update Period	True-Up Period	Effective Date of Rates
ER-2006-0314	Calendar Year 2005	June 30, 2006	September 30, 2006	January 1, 2007
ER-2007-0291	Calendar Year 2006	March 31, 2007	September 30, 2007	January 1, 2008
ER-2009-0089	Calendar Year 2007	September 30, 2008	March 31, 2009	September 1, 2009
ER-2009-0355	Calendar Year 2009	June 30, 2010	December 31, 2010	May 4, 2011

18
 19 KCPL's customers have paid and, absent adjustments, will continue to pay for higher
 20 capital costs, O&M expenses and fuel expense all directly due to an underperforming
 21 subpar SCR. Although B&W made attempts to correct the problems with the SCR, ultimately it
 22 was unable to meet the original contract guarantees. KCPL customers paid for the SCR based on
 23 the original contract price even though the SCR never met the original specifications. Since
 24 KCPL customers have paid and, absent adjustments, will continue to pay for excess costs due to
 25 the subpar performance of the Hawthorn 5 SCR, Staff made adjustments to reduce or exclude:

1 the capital costs directly related to the underperforming SCR; the ammonia costs that exceed
2 what KCPL would have incurred based on the original contract with B&W during the test year in
3 this case; and any outages directly related to the underperforming SCR which in effect, reduces
4 Staff's ongoing fuel level in this rate case. The adjustment for ammonia is reflected in Staff's
5 Accounting Schedule Adjustment E-11.1 Staff has also excluded the outages related to the SCR
6 failure which reduces Staff's determination of KCPL's fuel expense in the case.

7 *Staff Experts/Witnesses: Karen Lyons and Cary G. Featherstone*

8 **2. Hawthorn 5 Transformer**

9 In Case No. ER-2010-0355, the Commission established KCPL's level of rate base to
10 include the value of the Hawthorn 5 Generator Step-up Transformer (step-up transformer) at full
11 performance. The step-up transformers' failure resulted in a forced outage and increased
12 purchased power costs and other fuel expenses for ratepayers. Staff's treatment of the step-up
13 transformer is to adjust the outage rate for the period of 2005-2011 to remove outages related to
14 the failure of the step-up transformer. The adjustment to the outage rate reduces fuel expense
15 included in Staff's determination of KCPL's revenue requirement.

16 As discussed above in the Hawthorn 5 SCR section of this Report, Staff used KCPL's
17 generating unit outages during the period of 2005-2011 to determine an outage rate to use in its
18 fuel model. Because KCPL had increased outages and derates during this time period due to the
19 failure of its step-up transformer, Staff also adjusted KCPL's outage rate to exclude any outages
20 related to the transformer that occurred at the time of the failure (June 2005) to when the new
21 transformer was placed in service (June 2006) and, therefore, reduced the fuel expense Staff
22 included in its determination of KCPL's revenue requirement.

23 In August 2005, the step-up transformer on KCPL's Hawthorn 5 generating unit failed.
24 In September 2005, KCPL installed a backup step-up transformer. During June 2006, KCPL
25 installed a new step-up transformer. KCPL sued the contractors and subcontractors claiming
26 they were responsible for the step-up transformer failure. The case settled at the end of 2007,
27 and was finalized in 2008. In 2008 KCPL received a dollar settlement from Siemens Power
28 Transmission & Distribution, Inc. (Siemens) for the transformer failure.

29 KCPL customers paid in their rates all of KCPL's increased costs to KCPL resulting from
30 the step-up transformer failure. These costs included the salaries and benefits, office space, and

1 all employee-related costs of KCPL's attorneys and employees who worked on KCPL's dispute
2 with the contractors and subcontractors, increased maintenance, fuel and purchased power
3 expense, and increased expenses that were capitalized to the new plant. Although KCPL
4 customers have paid for all the increased costs associated with the transformer failure as
5 previously mentioned, in this case Staff only adjusted the Hawthorn 5 outage rate to account for
6 the impact of the step-up transformer failure. In the case of Hawthorn 5, the outages used in the
7 production cost model—fuel model is 7 years. The first year of the 7 year average is 2005 which
8 is the year in which the transformer failed and was replaced with a temporary back-up
9 transformer. The outage occurring in 2006 is also included in the 7 year average used for
10 outages in the fuel model.

11 As discussed near the end of the Hawthorn 5 SCR section above, although Staff is not
12 recommending an adjustment, in this rate case, for the additional purchased power costs KCPL
13 incurred as a result of these outages due to the failed transformer, in Staff's view KCPL's
14 customers have already paid for these costs by virtue of how Staff analyzes purchased power for
15 rate making purposes. Since KCPL customers have paid for all the costs related to the
16 replacement of the transformer and continue to pay for increased fuel expense based on the
17 outage period in this case (2005-2011), Staff is excluding the outages related to the transformer
18 failure which reduces Staff's determination of KCPL's fuel expense in the case.

19 *Staff Experts/Witnesses: Karen Lyons and Cary G. Featherstone*

20 **3. Bad Debt Expense**

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

29 Staff calculated the annualized bad debt expense by examining the billed revenues, net of
30 gross receipt taxes for the twelve months period ending September 30, 2011, and actual

1 12-month history of billed revenues that were never collected (actual net write-offs) for the
2 twelve months ending March 31, 2012. From this information a bad debt ratio was derived,
3 which was then applied to Staff's annualized level of retail revenues to obtain the annualized
4 level of bad debt expense. The apparent lag time between the net retail sales and actual net
5 write-offs in Staff's calculation is consistent with KCPL's position on how bad debt write-offs
6 are accounted.

7 KCPL asserts that it takes approximately six months for a customer's unpaid bill to be
8 written off after the customer receives service. Staff's adjustment for bad debt expense adjusts
9 the test year results to reflect a level of bad debt expense that is consistent with Staff's
10 annualized level of retail revenue. Adjustment E-172.1 in Staff's Accounting Schedule reflects
11 an annualized level of bad debt expense.

12 *Staff Expert/Witness: Karen Lyons*

13 **4. Advertising Expense**

14 In forming its recommendation of the allowable level of advertising expense, Staff relied
15 on the principles the Commission followed as a result of the 1986 Kansas City Power & Light
16 rate case, (Case No. EO-2005-0329 beginning with the 2006 rate case, Case No. ER-2006-0314).
17 In Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) (KCPL), the
18 Commission adopted an approach that classifies advertisements into five categories and provides
19 separate rate treatment for each category. The five categories of advertisements recognized by
20 the Commission are:

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

28 The Commission adopted these categories of advertisements because a utility's revenue
29 requirement should: 1) always include the reasonable and necessary cost of general and safety
30 advertisements; 2) never include the cost of institutional or political advertisements; and
31 3) include the cost of promotional advertisements only to the extent that the utility can provide
32 cost-justification for the advertisement. (Report and Order in KCPL Case No. EO-85-185, 28

1 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)). In response to data requests (DR), KCPL
2 provided a list of all costs associated with advertising and a brief description of those costs. Staff
3 held multiple meetings and phone discussions with KCPL to review these. The purpose of
4 Staff's review of KCPL's advertising costs was to ensure that only advertising costs for
5 programs necessary for the provision of safe and adequate utility service are included in KCPL's
6 cost of service. For example, all costs for safety advertising and indirectly related to safety
7 advertising were included as well as other costs necessary for KCPL to communicate with its
8 customers on utility matters. Staff removed test year expenses incurred by KCPL for advertising
9 programs that are appropriately classified as institutional image in nature.

10 Staff has come to the conclusion to make adjustments to account 908.000 and 909.000, as
11 well as pick up the Company adjustments to account 930.100. Finally, Staff chose to pick up the
12 Company adjustments for account 930.1, that simply reflect the change between test year and
13 known and measurable.

14 Staff focused on campaigns, not individual advertisements, which is consistent with the
15 Commission's discussion on the topic as stated in its rate case order, the *AmerenUE Report and*
16 *Order* in ER-2008-0318. Adjustments E-178.2, E-183.2 and E-225.2.

17 *Staff Expert/Witness: Bret G. Prenger*

18 **5. Dues and Donations**

19 Staff reviewed the list of membership dues paid and donations made to
20 various organizations that KCPL charged to its utility accounts during the test year. Staff
21 included all dues payments made by KCPL to each area's Chamber of Commerce, but
22 removed the state-level Chamber of Commerce. Allowing Chamber fees for individual cities
23 or the state-level Chamber, but not both, is consistent with how Staff has treated Chamber
24 fees for utility companies in past cases. Staff removed all other dues as costs not necessarily
25 in the provision of utility service. The adjustment was made to KCPL in account 930.2.
26 In addition to this adjustment, Staff removed costs in which it considers the expenses to be
27 personal or of no benefit to the ratepayer and thus, not included in a utility's cost of service.
28 Adjustment E-227.4.

29 *Staff Expert/Witness: Bret G. Prenger*

1 G. Special Bonus and Severance Payments

2 This adjustment removes test year spousal travel, ad hoc bonuses, and severance
3 payments for former executives.

4
5 H. Miscellaneous Coding Corrections

6 These adjustments are miscellaneous accounting coding corrections.

7 Staff has reflected these adjustments to the test year cost of service for KCPL as Staff
8 Accounting Adjustments E-199.2, E-117.1, E-185.1, E-199.2, E-218.1, E-218.2, E-218.3,
9 E-218.4, E-205.1, E-226.1, E-179.1, E-184.2, E-152.1, E-204.1, E-158.2, E-48.1, E-106.1,
10 E-196.2, E-227.1, E-196.3, E-199.4 and E-227.2.

11 *Staff Expert/Witness: Keith Majors*

12 **7. Deloitte & Touche Expenses**

13 In the test year ending September 2011, Staff identified several expenses originating from
14 vendor Deloitte & Touche. The general description and amount of these expenses are as follows
15 per KCPL's response to Staff Data Request 303:

- 16 • Research and consultations regarding potential Subpart F income issues
17 relating to MPS Canada Corporation paying off the intercompany payable
18 owed to its parent: \$2,067
- 19 • Research and consultations regarding potential worthless stock deduction on
20 liquidation of MPS Canada Corporation, including analysis of Forms 5471
21 filed in prior years and discussion regarding timing of worthlessness: \$6,799
- 22 • Research and consultations regarding carryback of expiring Aquila Kansas
23 net operating losses, including apportionment and Section 382 limitation
24 considerations: \$2,644
- 25 • Research and consultation regarding potential worthless stock loss on
26 liquidation of foreign subsidiary, including analysis of stock basis
27 calculation: \$4,990

28 The above expenses are not related to KCPL's regulated operations of providing electric
29 utility services in Missouri, and should therefore not be included in its revenue requirement for
30 setting rates in Missouri.

31 In addition to the above expenses, Deloitte & Touche provided research and consulting
32 services concerning Advanced Coal Tax Credit normalization issues. These expenses total
33 \$31,249 in the test year ending September 2011. As discussed by Staff Expert Cary G.

1 Featherstone, this issue is wholly created by KCPL, and any expenses incurred due to KCPL's
2 failure to include Empire and GMO in the initial stages of obtaining the Advanced Coal Tax
3 Credit should not be borne by ratepayers and should not be included in the cost of service.

4 Adjustment E-204.5 removes test year Deloitte & Touche expenses from KCPL's
5 revenue requirement.

6 Adjustment E-204.6 removes test year Deloitte & Touche expenses related to the
7 Advanced Coal Credit from KCPL's revenue requirement.

8 *Staff Expert/Witness: Keith Majors*

9 **8. Expenses Concerning the Advanced Coal Tax Credit**

10 In KCPL's last rate case, Case No. ER-2010-0355, at page 174 of its April 12, 2011
11 Report and Order, the Commission denied KCPL recovery of expenses it incurred defending
12 itself in an arbitration with Empire, Missouri Joint Municipal Electric Utility Commission
13 (MJMEUC) and Kansas Electric Power Cooperative, Inc. (KEPCO) brought against it over the
14 Advanced Coal Tax Credit for Iatan 2 as follows:

15 If the Commission grants KCP&L recovery of these legal fees, the
16 Commission will be encouraging this utility to engage in improper actions.

17 The Commission determines that the arbitration expenses KCP&L
18 has incurred in defending itself for its imprudent acts are disallowed from
19 KCP&L's cost of service for setting rates.

20 In the current case, Staff Data Request 290 Staff requested KCPL to provide a listing of
21 its additional expenses related to the Advanced Coal Credit arbitration and litigation. In its
22 response KCPL listed an additional \$30,984 of legal expenses, \$10,650 of which is in the test
23 year ending September 2011. The total legal and consulting expenses KCPL has incurred from
24 inception to date concerning this arbitration is \$648,223.

25 In Case No. ER-2010-0355 the Commission issued an order—Report and Order
26 Directing KCPL and GMO to Apply to the IRS to Revise the Memorandum of Understanding
27 Regarding the Advanced Coal Tax Credits for Iatan, issued on March 16, 2011—directing KCPL
28 to do the following concerning the Iatan 2 Advanced Coal Tax Credit:

1 2. No later than April 5, 2011, GMO and KCPL shall apply, at the
2 shareholders' expense, to the Internal Revenue Service for an amendment
3 of the Memorandum of Understanding that would allow KCP&L Greater
4 Missouri Operations Company to obtain a share of the Section 48A tax
5 credits for Iatan 2. . . .

6 KCPL has incurred \$27,358 in legal expenses to seek a reallocation of the Advanced
7 Coal Tax Credit to GMO, \$7,025 of which is in the test year cost of service.

8 KCPL identified this test year amount in the response to Staff Data Request 293. In that
9 response, KCPL stated the following:

10 2. These costs were booked to regulated operations in error. KCP&L
11 agrees that these costs should not be included.

12 In a letter from the IRS dated August 24, 2011, the IRS declined to modify the
13 Memorandum of Understanding the Commission ordered KCPL and GMO to seek. Directly
14 because of the decisions of KCPL's employees not to inform GMO of the availability of the
15 credit and not to have GMO seek to reallocate from KCPL to GMO an appropriate share of the
16 Advanced Coal Tax Credit awarded to KCPL, KCPL has incurred and will incur expenses in this
17 case related to its witness on this issue, Salvatore Montalbano of PricewaterhouseCoopers, LLP
18 (PwC). According to the response to Staff Data Request 299, Case No. ER-2012-0174, through
19 May 2012, KCPL has incurred \$20,700 of expenses related to this witness, as well as another
20 PwC employee, Bob Hriszko, both of which are billed to KCPL at \$600 per hour, the highest
21 hourly rate of any consultant or attorney utilized by KCPL or GMO in the current rate cases.
22 KCPL directly charged Mr. Montalbano's fees to rate case expense.

23 Because KCPL incurred Mr. Montalbano's fees only because of the failure of KCPL's
24 employees to inform GMO of or have GMO seek a portion of the tax credit earlier, Staff
25 disallowed Mr. Montalbano's fees from KCPL's rate case expenses in this rate case. Staff
26 recommends disallowing these fees not only from rate case expense through the true-up, but also
27 any post-true up rate case expense and from any normalized level of rate case expense.

28 The adjustment for Mr. Montalbano's fees is identified in the "Rate Case Expenses"
29 section of this Cost of Service Report.

30 Adjustment E-204.3 removes the test year expenses related to the Advanced Coal Credit
31 Arbitration from KCPL's cost of service.

1 Adjustment E-204.4 removes the test year expenses related to the application to the IRS
2 to amend the Memorandum of Understanding.

3 *Staff Expert/Witness: Keith Majors*

4 **9. Legal Fee Reimbursements**

5 In its direct case, KCPL included Adjustment CS-115 to amortize two legal fee
6 reimbursements, one of which was amortized over three years in the most recent KCPL rate case,
7 Case No. ER-2010-0355. The Missouri jurisdictional balances of these reimbursements are
8 treated as regulatory liabilities on KCPL's books and records. KCPL has not yet begun the
9 amortization of the most recent reimbursement that was received in November 2010. Staff
10 included a three-year amortization of these legal reimbursements as a reduction to KCPL's cost
11 of service as Adjustments E-205.2 and E-205.3.

12 *Staff Expert/Witness: Keith Majors*

13 **10. Debit/Credit Card Acceptance Program**

14 In February 2007, KCPL implemented a Credit/Debit Card payment program designed to
15 offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their
16 accounts electronically. The program is offered by KCPL in an agreement with Western Union
17 through its SpeedPay service, which acts as a third party facilitator for the processing of
18 payments to KCPL. When payment is made by a customer through the credit or debit card
19 system, KCPL will receive payment from Western Union. Payment options available to
20 customers through the program include the Interactive Voice Response System ("IVR") and or
21 by registering on KCPL's website. Payment through the website offers two options one time
22 payments or what the Company terms the, "recurring card payment option," which is available
23 through registration on its website. The cost for providing this service is absorbed by KCPL and
24 later built into rates; therefore, customers who use this payment option are not charged any direct
25 transaction fees. Since the introduction of the program in February 2007, customer participation
26 has been gradually increasing. Participation is projected to increase into the future as more
27 customers become aware of the program. As customer participation increases, the per unit
28 transaction cost to KCPL for providing the debit/credit payment service will decline.

1 Staff included in its cost of service an annualized amount associated with the credit and
2 debit card program based upon the total card level and per unit transaction cost as of the test
3 year, twelve-month period ended September 30, 2011, to represent an ongoing level of costs.
4 Staff will review these costs through the true up period, August 31, 2012 and make any
5 necessary adjustments.

6 *Staff Expert/Witness: Karen Lyons*

7 **11. Accounts Receivable Bank Fees**

8 KCPL's selling of accounts receivable results in KCPL collecting revenues on an
9 accelerated basis from a lending institution. The benefit to KCPL is that it receives enhancement
10 to its cash management. For rate making purposes, this enhancement is reflected in the
11 acceleration of the collection process, identified through a shorter revenue lag in the CWC
12 schedule than otherwise would have occurred absent the sale of the accounts receivable.

- 13 • KCPL sells its accounts receivable as follows:
- 14 • KCPL sells all of its electric receivables daily at a discount and on a
15 non-recourse basis to Kansas City Power & Light Receivables
16 Company ("KCREC"), a wholly-owned subsidiary of KCP&L.
- 17 • KCREC sells an undivided interest in the receivables to Victory
18 Receivables Corporation ("Victory"), a wholly-owned subsidiary of
19 the Bank of Tokyo Mitsubishi.
- 20 • Victory issues commercial paper to fund the purchase of the
21 receivables from KCREC.
- 22 • KCREC uses the cash it receives from Victory to partially pay KCPL
23 for the receivables.
- 24 • KCREC gives a promissory note to KCPL for the difference between
25 the partial payment and the total discounted purchase price.
- 26 • KCREC pays Victory interest, program fees and a commitment fee.

27 KCREC pays KCPL interest on the promissory note.

28 The adjustment for bank fees relates to the cost of the sale of its accounts receivable.
29 Staff included the test year level of bank fees paid by KCPL to KCREC as Adjustment E-174.1
30 on Accounting Schedule 9. Adjustment E-174.2 reflects the difference between the test year
31 level and Staff's annualized level of bank fees.

32 *Staff Expert/Witness: V. William Harris*

1 **13. Insurance Expense**

2 Staff's recommend treatment of Insurance Expense is to treat insurance premium
3 prepayments as an asset that is included in rate base and is amortized to expense ratably over the
4 life of the insurance, by annualizing the level of insurance expense and allocate an appropriate
5 portion of the expense to KCPL's cost of service. Insurance expense is the cost of protection
6 obtained from third parties by utilities against the risk of financial loss associated with
7 unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur
8 insurance expense in order to minimize their liability associated with unanticipated losses for
9 property assets and personal injury from accidents. Certain forms of insurance reduce
10 ratepayer's exposure to risk. Premiums for insurance are normally pre-paid by utilities;
11 i.e., payment is made by the utility to the insurance vendor in advance of the policy going into
12 effect. These insurance payments are normally treated as prepayments, with the amount of the
13 premium being booked as an asset and amortized to expense ratably over the life of the period
14 the insurance is in force. The unamortized balance of the prepaid insurance account (either the
15 period-ending balance or a 13-month average balance) is included in rate base, with an
16 annualized level of insurance expense included in rates.

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

- 19 ▪ Crime
- 20 ▪ Fiduciary Liability
- 21 ▪ Directors and Officers
- 22 ▪ General Liability/Umbrella
- 23 ▪ Excess Directors & Officers
- 24 ▪ Excess Liability
- 25 ▪ Excess fiduciary
- 26 ▪ Workman's Compensation
- 27 ▪ Excess Workman's Compensation
- 28 ▪ Property
- 29 ▪ Labor Management Trust Fiduciary
- 30 ▪ Auto Liability
- 31 ▪ Bonds

1 Staff reviewed the policies and verified the current insurance premiums for
2 each insurance type. An annualized amount was determined and allocated to GMO-MPS and
3 GMO-L&P and reflected in those entities cost of service (Case No. ER-2012-0175). KCPL
4 renewed several insurance policies in May 2012. As part of its true-up audit, Staff will review
5 these policies and recommend any necessary adjustments. The same methodology used in
6 annualize Insurance Expense as of March 31, 2012 will be used to annualize Insurance Expense
7 for August 31, 2012. The Commission should base its awarded revenue requirement on an
8 annualized level of Insurance Expense. The annualized levels for KCPL's portion of the
9 insurance costs are reflected in Adjustments E-207.1 and E-208.3.

10 *Staff Expert/Witness: Patricia Gaskins*

11 **14. Injuries and Damages**

12 Staff's recommended treatment of injuries and damages is to normalize KCPL's costs
13 associated with injuries and damages, using a three-year average of actual cash payments made
14 by KCPL and paid to individuals who had an injury and claim. Injuries and damages relate to
15 insurance claims that are not covered by insurance policies. Injuries and damages usually consist
16 of claims associated with general liability, workman's compensation, and auto liability. Staff
17 analyzed five years of data and determined a three-year average, including the period of 2009
18 through 2011, using the actual cash payments to normalize KCPL's costs associated with injuries
19 and damages. The actual cash payments are those paid to individuals who had an injury and
20 claim. As a result of these injuries, KCPL made cash settlements. A three-year average was
21 used based on the data received from KCPL. This normalization of known and measurable
22 changes of the actual cash payments over a multi-year period is the appropriate method that the
23 Commission should use in the ratemaking process and is consistent with KCPL's method to
24 normalize injuries and damages in its rate case.

25 Although the Commission accepted KCPL's request in Case No. ER-2006-0314, to use
26 the accrual method of accounting for calculating the costs associated with injuries and damages,
27 KCPL has not since used the accrual method in its other rate requests. Staff has typically used
28 actual cash payments to determine a normalized level of injuries and damages because the
29 estimates used in the accrual method are not as reliable and do not meet the criteria of known and
30 measurable costs typically used in the ratemaking process.

1 Staff's methodology uses historical actual cash payment amounts to calculate the
2 normalized level of expense and Staff's method is the same method used by KCPL in this rate
3 case. The Commission should base its awarded revenue requirement on Staff's recommended
4 normalized level of expenses associated with injuries and damages, which Staff calculates using
5 known and measurable actual cash payments made, to determine the appropriate level of
6 expense. Adjustment E-208.1 reflects a normalized level of costs for injuries and damages.

7 *Staff Expert/Witness: Patricia Gaskins*

8 **15. Property Tax Expense**

9 Staff's recommended treatment of Property Tax Expense is to annualize property tax
10 expenses based upon property KCPL had in-service on January 1, 2012, by multiplying that
11 property amount to Staff's property tax ratio derived from 2011 tax payments. Staff adjusted test
12 year property tax expense in order to include in rates the annualized level of 2012 property taxes.
13 Each year KCPL is billed by each of the taxing authorities that have jurisdiction over KCPL's
14 property. Tax bills for the year are based (assessed) on the property KCPL owns exclusively on
15 January 1st of that calendar year. The property taxes assessed on January 1 of each year are
16 typically not due to the taxing authorities until December 31 of that same year, and in the state of
17 Kansas, part of the year's property taxes are not due until late in the first quarter of the following
18 year. The test year used in this case is the 12-month period ending September 30, 2011, updated
19 through March 31, 2012. Since the update period in this case is March 31, 2012, Staff
20 determined the annualized property taxes based on the property KCPL had in-service on
21 January 1, 2012. Staff applied a property tax ratio based on actual 2011 property tax payments
22 to January 1, 2011, plant. This ratio of property taxes when applied to the January 1, 2012, plant
23 provides the amount of property taxes expected to be paid for 2012. Because the test year in this
24 case is September 30, 2011, property tax expenses for 2012 was annualized as of the
25 January 1, 2012 date. This calculation is an estimate of the total 2012 property tax expense.
26 Both Staff and KCPL typically accomplished this by looking to the tax rate paid for the previous
27 year, and then applying it to the property owned at the start of the current year.

28 For the current rate case, Staff obtained from KCPL the total amount of taxable property
29 owned on January 1, 2012, and then applied to it the tax rate assessed to KCPL in 2011. The
30 property tax rate assessed in 2011 is calculated by dividing the total amount of property tax paid

1 by KCPL by the total cost of the taxable property owned on January 1, 2011. Any required
2 payments in lieu of taxes (“PILOTs”) applicable to non-taxable property were added to the total
3 estimated tax for 2012. Staff recommends this method of calculation as providing the best
4 available information, since it relies on the actual January 1, 2012, balance of KCPL’s property,
5 and uses the most recent, known tax rate (2011), without attempting to estimate any change in
6 the rate of taxation for 2012 that is not known as of the update period March 31, 2012. Staff’s
7 approach is consistent with that taken previously and received several favorable rulings from the
8 Commission in prior cases, most recently in KCPL 2006 rate case. In its *Report and Order*
9 issued in Case No. ER-2006-0314 the Commission stated the following:

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

17 Based on the methodology addressed earlier, Staff made an adjustment to include an
18 annualized amount for property taxes. The Commission should base its awarded revenue
19 requirement on Staff’s 2011 property tax ratio applied to the total amount of taxable property
20 KCPL owned on January 1, 2012. Adjustment E-257.1 reflects the annualized levels.

21 *Staff Expert/Witness: Patricia Gaskins*

22 **16. Rate Case Expense**

23 Staff recommends the Commission include a normalized level of rate case expense in
24 KCPL’s revenue requirement used for setting rates in this case, except for the rate case expenses
25 KCPL incurred under its Regulatory Plan, which are subject to deferral and amortization.

26 Staff adjusted KCPL’s post-true-up 2010 Rate Case expense allocable to Missouri
27 (post December 31, 2010) from \$2,605,670 to \$1,955,197 to account for the reimbursement of
28 rate case expense KCPL received from Empire, then Staff further adjusted it to \$1,533,697 based
29 on disallowing costs KCPL incurred post December 31, 2010, for (1) Schiff Hardin
30 personnel who did not testify at the evidentiary hearing during the 2010 Rate Case — a
31 disallowance of \$392,727, (2) SNR Denton’s defense in the 2010 Rate Case of KCPL’s actions

1 regarding the Iatan 2 Advanced Coal Tax Credit—a disallowance of \$15,365 and (3) The
2 Communication Counsel of America’s witness development and coaching services — a
3 disallowance of \$13,408. Like KPCL, Staff did not include NextSource costs related to
4 Chris Giles in KCPL’s post-true-up rate case expense.

5 Staff disallowed the non-witness Schiff Hardin personnel costs from KCPL’s rate case
6 expense because the number of personnel for the services rendered was excessive, their rates
7 were high and KCPL’s post true-up 2010 rate case expense is excessive unreasonable. Staff’s
8 support for these rationales follows. Staff included in rate case expense the costs for the services
9 of Schiff Hardin personnel and others who testified and whose services were billed to KCPL
10 through Schiff Hardin—Mr. Roberts, Daniel F. Meyer, Steven Jones and Jim Wilson.

11 As explained below, Staff disallowed the outside litigation counsel SNR Denton fees and
12 expenses associated with KCPL’s defense of its actions regarding the Iatan 2 Advanced Coal Tax
13 Credit because those actions were imprudent and KCPL was not justified in employing outside
14 counsel for this issue.

15 Consistent with how the Commission disallowed The Communication Counsel of
16 America witness development and coaching services costs in the 2010 Rate Case, Staff
17 disallowed The Communication Counsel of America witness development and coaching services
18 costs KCPL incurred post the December 31, 2010, true-up cut-off date in the 2010 Rate Case.

19 In its 2010 Rate Case, the Commission found in Findings of Fact 475 that KCPL and
20 GMO made no adjustments or corrections to any of Schiff Hardin’s bills for legal
21 services or any experts’ invoices. To date, KCPL has yet to identify any adjustment made by
22 any law firm vendors.

23 Background

24 Rate case expenses are costs a utility incurs in preparing and executing the filing of its
25 rate case. In the instant case, KCPL has incurred rate case expenses for outside legal counsel,
26 temporary labor, and outside consultants.

27 Generally, Staff treats rate case expense as an expense necessary to providing utility
28 service and includes in the utility’s revenue requirement a normalized level of rate case expense
29 based on the rate case expenses the utility has incurred in the past. After determining the
30 normalized level Staff divides it over the period of time it estimates will pass before the next rate
31 case and includes an annual amount of the normalized level in the utility’s revenue requirement.

1 Under a normalization approach to rate recovery of rate case expense, this cost is not
2 “amortized” for ratemaking purposes, and the Company’s recovery of this expense in rates is not
3 tracked against its actual rate case expense amounts. However, because KCPL’s Regulatory
4 Plan contemplated four rate case filings over less than four years Staff did not oppose the
5 “defer and amortize”, or “vintage accounting” approach that KCPL requested in each of those
6 rate cases—Case Nos. ER-2006-0314 (“2006 Rate Case”), ER-2007-0291 (“2007 Rate Case”),
7 ER-2009-0089 (“2009 Rate Case”) and ER-2010-0355 (“2010 Rate Case”). For the remaining
8 rate case expenses for each of these cases, as adjusted, Staff used a “defer and amortize”
9 approach to calculate the associated revenue requirement to be included in the following rate
10 case. However, because the four Regulatory Plan rate cases are completed, Staff is returning to
11 its typical normalization approach for establishing an ongoing level of rate case expense to
12 include in KCPL’s revenue requirement in this case, *i.e.*, Staff is not proposing KCPL be allowed
13 to defer and amortize any rate case expenses incurred for this instant case.

14 While the “tracker,” or “defer and amortize” method utilized during KCPL’s Regulatory
15 Plan results in the exact amount of rate case expense recovered in rates, there is a distinct
16 disincentive to adequately and prudently manage expenses. On the other hand, using a
17 normalized level of costs incents the utility to actively manage costs for efficient operations,
18 similar to a variety of other expenses Staff normalizes.

19 Use of Defer and Amortize Procedure

20 Under the defer and amortize approach to rate case expense, for each rate case, KCPL’s
21 rate case expenses incurred for that rate case after the true-up cut-off date in the case were a
22 separate vintage deferral. Each of those vintage deferrals was amortized over an appropriate
23 time and an annual amount of the amortized level included in the revenue requirement for
24 KCPL’s next rate case. For this case Staff is including in KCPL’s revenue requirement an
25 annual amount of amortization of the last of the KCPL Regulatory Plan rate case expense vintage
26 deferrals. In practice, these back-to-back amortizations have functioned much like the trackers
27 the Commission has authorized for vegetation management and pension expenses.

28 In the April 4, 2009, *Non-Unanimous Stipulation and Agreement* the Commission
29 approved and ordered the signatories’ to carry out their agreement that any over recovery of the
30 amortization of the Company’s rate case expense in the 2006 Rate Case would be used to offset
31 the amount of rate case expense incurred and deferred in the 2009 Rate Case. This application of

1 over-recovered expenses, while not an approach that would be used under normal ratemaking
 2 circumstances, is consistent with the “defer and amortize” approach, which is functionally
 3 similar to tracker accounting. For the cases brought under KCPL’s Regulatory Plan, Staff has
 4 continued this rate case tracker approach and applied the over recovery of rate case expense from
 5 the 2007 Rate Case against KCPL’s rate case expense deferral in the 2009 Rate Case, and
 6 applied the over recovery of rate case expense from the 2009 Rate Case against KCPL’s rate case
 7 expense deferral in the 2010 Rate Case.

8 In the 2010 Rate Case, Staff included the expenses KCPL incurred after the true-up
 9 cut-off date of the 2009 Rate Case, and the expenses KCPL incurred related to the
 10 April 2010 proceedings concerning Staff’s Iatan Construction Audit and Prudence Review in
 11 File No. EO-2010-0259, with the rate case expenses in the 2010 Rate Cases incurred
 12 through December 31, 2010. Consistent with its approach in the 2010 Rate Case, Staff again
 13 aggregated the requested 2010 Rate Case expense for recovery under the defer and amortize
 14 approach. The rate case expenses requested for recovery through December 31, 2010 in the 2010
 15 KCPL and GMO Rate Cases, including 2009 Rate Case post-true-up expenses, are shown in the
 16 below table:
 17

Rate Case Expenses Requested in 2010 Rate Cases	
Company/District	Total
KCPL - MO	\$4,593,427
GMO-MPS	\$2,001,855
GMO-L&P	\$1,175,870
Total Through 12/31/2010	\$7,771,152

18
 19 **

20
 21
 22
 23
 24
 25 **

1 Most of the rate case expense amounts subject to the deferral and amortization treatment
 2 have either been agreed to or ordered in prior rate cases. However, there is a portion of rate case
 3 expense relating to the 2010 Rate Case that KCPL incurred after the true-up cut-off date in that
 4 case and which the Commission has ordered to also be given deferral and amortization treatment.
 5 In the Commission's *Report and Order* in the 2010 Rate Case, the Commission specifically
 6 ordered on Page 171 the deferral of post-true-up rate case expenses as follows:

7 The amounts allowed and disallowed represent the true-up amounts
 8 recorded as of December 31, 2010, and are not final rate case expenses.
 9 Rate case expenses for these cases after the true-up will be deferred for
 10 possible recovery in the next rate case, subject to review for prudence and
 11 reasonableness.

12 KCPL's and GMO's rate case expenses paid after December 31, 2010 in the 2010
 13 Rate Cases are shown in the below table. The sharing of rate case expenses with Empire
 14 is also shown:
 15

Additional Expenses from 2010 Rate Cases Post True-Up			
Company/District	Total Incurred	Empire Shared Expenses	Net Incurred
KCPL - MO	\$2,605,670	(\$650,473)	\$1,955,197
GMO-MPS	\$1,230,865	(\$395,437)	\$835,428
GMO-L&P	\$247,167	(\$123,831)	\$123,336
Total Expense	\$4,083,702	(\$1,169,741)	\$2,913,961

16
 17 For comparison, the total rate case expenses incurred in the 2010 Rate Case and Case No.
 18 ER-2010-0356 of \$11,854,854, and \$10,685,113, respectively, net of Empire shared expenses
 19 and including 2009 Rate Case post-true-up rate case expenses and the expense associated with
 20 File No. EO-2010-0259, are shown in the below table:
 21

Total Incurred Rate Case Expenses – 2010 Rate Cases			
Company/District	Total Incurred	Empire Shared Expenses	Net Incurred
KCPL - MO	\$7,199,097	(\$650,473)	\$6,548,624
GMO-MPS	\$3,232,720	(\$395,437)	\$2,837,283
GMO-L&P	\$1,423,037	(\$123,831)	\$1,299,206
Total Rate Case Expenses	\$11,854,854	(\$1,169,741)	\$10,685,113

1 To give the Commission a perspective of the increasing rate case expenses, the table
 2 below details the total incurred rate case expenses from the prior three rate cases for KCPL,
 3 GMO – MPS and GMO – L&P:
 4

Rate Case Expenses for 2005-2009 Rate Cases				
Total Costs	KCPL - MO	GMO - MPS	GMO - L&P	Total
2005/2006 Rate Cases	1,400,291	345,365	110,021	1,855,677
2007 Rate Cases	715,349	520,253	130,063	1,365,666
2009 Rate Case	2,171,609	468,928	445,079	3,085,616
3 Case Average	1,429,083	444,849	228,388	2,102,320

5
 6 KCPL's projected rate case expenses for the 2012 Rate Cases from KCPL's direct filing
 7 are detailed below:
 8

KCPL March 31, 2012 Rate Case Expenses and Total Projected 2012 Rate Case Expenses				
	KCPL - MO	GMO - MPS	GMO - L&P	Total
2012 Rate Case Through March 31	224,006	83,184	61,503	\$368,693
2012 Projected - KCPL Workpaper	2,019,535	1,099,357	388,959	\$3,507,851

9
 10 Staff made the adjustments to KCPL's post-true-up 2010 Rate Case expense that are
 11 explained in detail in the sections below.

12 **Adjustments to Amounts to Be Deferred and Amortized**

13 **Schiff Hardin Rate Case Expense Adjustment**

14 In the 2010 Rate Cases, KCPL and GMO incurred a total of \$7.7 million of combined
 15 rate case expense as detailed in the table in the section above. Of that total, Schiff Hardin
 16 expenses totaled \$1.3 million through the true-up in those cases, prior to any expenses related to
 17 hearings. These amounts are charged to rate case expense, and do not include any Schiff Hardin
 18 charges capitalized to the Iatan Construction Project:
 19
 20

21 *continued on next page*
 22
 23

1

Schiff Hardin Rate Case Expenses Currently in the Cost of Service	
Schiff Hardin Rate Case Expenses	December 2010 True Up Cutoff
KCPL - MO	\$988,496
GMO-MPS	\$275,291
GMO-L&P	\$89,130
Total	\$1,352,917

2

3

4

5

Including the amounts paid after the true-up in the 2010 Rate Case, the total paid to Schiff Hardin charged to rate case expense was \$3,534,400:

Total Schiff Hardin costs charged to 2010 Rate Case Expenses			
Schiff Hardin Rate Case Expenses	December 2010 True Up Cutoff	Post December 2010	Total
KCPL-MO	988,496	1,003,482	1,991,978
GMO-MPS	275,291	916,223	1,191,514
GMO-L&P	89,130	261,778	350,908
Total	1,352,917	2,181,483	3,534,400

6

7

8

9

KCPL provided a description of the duties Schiff Hardin performed in the 2010 Rate Cases in Tim Rush's true-up rebuttal testimony in Case No. ER-2010-0355 (Exhibit No. KCP&L 115) on page 6 as follows:

10

11

12

13

Schiff Hardin assisted in testimony preparation, coordination of prudence strategy, document analysis and review, preparation of exhibits, legal research regarding prudence analysis of prior MPSC disallowances, cross examination preparation, and issue identification.

14

15

16

17

KCPL and GMO incurred significant rate case expenses from Schiff Hardin after the December 31, 2010 true-up in the 2010 Rate Cases. The total Schiff Hardin post-true-up expenses, by invoice, are shown in the table below:

1

Post-True-Up Schiff Hardin Invoices	
Schiff Hardin Invoice No.	Total
1555304	\$343,135
1544353	\$437,149
1567750	\$415,721
1577839	\$147,535
1582954	\$22,583
1594314	\$4,466
1555941	\$810,895
Total	\$2,181,483

2

3

4

5

A portion of those rate case expenses were borne by Empire, as previously discussed in this report. The rate case expenses, net of Empire's share, are shown below:

Empire Reimbursement of Schiff Hardin Expenses				
Schiff Hardin Post True-up	% Charged	Total	Less: Empire Sharing	Net Expense
KCPL - MO	46%	\$1,003,482	(\$198,389)	\$805,093
GMO-MPS	42%	\$916,223	(\$162,241)	\$753,982
GMO-L&P	12%	\$261,778	(\$22,880)	\$238,898
Total	100%	\$2,181,483	(\$383,510)	\$1,797,973

6

7

8

9

10

11

12

13

continued on next page

14

15

16

17

18

1 As of December 31, 2010, the annualized payroll utilized by Staff in its true up case
 2 included 20 (twenty) individuals employed by KCPL licensed to practice law in the State of
 3 Missouri. Of those in the Law, Regulatory, and General Counsel departments, the average
 4 hourly rate with benefits as of December 31, 2010 was ** ___ **, as opposed to the
 5 significantly higher hourly rates KCPL paid for legal services in the 2010 Rate Cases. The
 6 hourly and annual rates paid by KCPL, and consequently ratepayers, as of the 2010 Rate Case
 7 true-up and Staff's March 31, 2012 update in the 2012 Rate Case appear in the tables below⁸²:

8 **

9

10

11 **

12 Not only are these rates substantially lower than KCPL's various external counsel, the
 13 fully allocated cost of these employees is being paid and will be paid by KCPL's and GMO's
 14 ratepayers. Considering the hours billed by Schiff Hardin detailed above, other than amounts
 15 billed by Mr. Roberts, KCPL paid for the equivalent of nearly 4 (four) KCPL in-house attorneys
 16 *for an entire year*⁸³. This comparison considers only one legal vendor, it does not take into
 17 account expenses from The Cafer Law Office, Duane Morris, Fischer & Dority, Morgan Lewis
 18 & Bockius, Polsinelli Shalton Flanigan Suelthaus, Skadden Arps Slate Meagher & Flom, SNR

⁸² The benefits rate of 0.61, or 61% of the hourly rate, was utilized as an estimate by KCPL in its Adjustment CS-49, Distribution Intelligence and Tech Support ("DFITS") as supported by KCPL witness William Herdegen, an adjustment unrelated to rate case expense. Staff is utilizing this rate only as an estimate for comparison purposes, not as a representation of actual expenses.

⁸³ **

**

1 Denton, Spencer Fane Britt & Browne, and Stinson Morrison & Hecker, all of whom billed
2 KCPL and GMO for 2010 Rate Case legal expenses.

3 The Commission, on Page 163 of its 2010 Rate Case *Report and Order*, recognized that
4 KCPL in prior cases had utilized in-house attorneys:

5 476. In its last litigated rate case, KCP&L in-house attorneys shared in a
6 great deal of the work associated with litigating that case. Those
7 attorneys, whose salary and benefits are already recovered through rates,
8 litigated issues associated with policy, off-system sales margins, Hawthorn
9 5 settlement costs and uranium enrichment overcharges. [footnote
10 omitted]

11 The Commission, in its 2010 Rate Case *Report and Order* was presented with and
12 ordered adjustments to rate case expense concerning NextSource expenses and The
13 Communication Counsel of America (CCA) expenses. Particularly, the Commission found on
14 Page 171 of its *Report and Order* that the services provided could have been performed by in-
15 house attorneys:

16 ...The CCA provided witness development and coaching services, routine
17 tasks typically performed by retained counsel, internal or otherwise. The
18 KCC also disallowed similar expenses as unjust and unreasonable. The
19 Commission determines that the CCA expense should be disallowed as
20 duplicative of other services that were performed or should have been
21 performed [sic] KCPL's and GMO's attorneys.

22 For the same reasons the Commission disallowed the CCA expenses, the Staff
23 recommends disallowance of all Schiff Hardin non-witness expenses.⁸⁴

24 As identified by KCPL witness Tim Rush in the 2010 Rate Case, the Schiff Hardin non-
25 witness expenses related to "testimony preparation, coordination of prudence strategy, document
26 analysis and review, preparation of exhibits, legal research regarding prudence, analysis of prior
27 MPSC disallowances, cross examination preparation, and issue identification." These are
28 activities that are reasonably expected of KCPL in-house attorneys and staff, at a substantially
29 discounted rate.

30 To compute Staff's adjustment, Staff identified all charges not related to Mr. Roberts,
31 Daniel F. Meyer, and Steven Jones, who were KCPL witnesses billed through Schiff Hardin in
32 the 2010 Rate Case. Staff did not adjust hourly billings or expenses related to these individuals.

⁸⁴ Mr. Roberts was the sole employee witness provided by Schiff Hardin. Daniel Meyer and Steven Jones also appeared as witnesses but are not employed by Schiff Hardin.

1 Staff did not remove charges related to Jim Wilson of Jim Wilson & Associates, who provided
2 scheduling expertise related to the Iatan Project, and was not directly involved in preparation or
3 execution of the 2010 Rate Case hearings. Staff identified travel expenses not related to these
4 individuals for its recommended adjustment. The total adjustment is detailed below. The
5 amounts have been adjusted for the Empire sharing of rate case expenses:
6

Staff Recommended Schiff Hardin Adjustment	
Schiff Hardin Expense Category	Amount
Hourly Fees	1,070,178
Disbursements	70,250
Less Empire Share	(286,673)
Total Adjustment	\$853,755

Allocation	Total	\$853,755
KCPL - MO	46%	\$392,727
GMO-MPS	42%	\$358,577
GMO-L&P	12%	\$102,451

7
8
Failure to Contain Costs

9
10 During the hearings in the 2010 Rate Case, the Commission asked several questions of
11 KCPL's policy witness concerning expenses from Schiff Hardin:
12

13 Commissioner Kenney:

14 Q. Okay. Was there ever a time when you objected to Schiff [sic]
15 Hardin's bills and asked them to make adjustments?

16 KCPL Witness Blanc:

17 A. No. There were times that I would talk to the people who were
18 working closely with them and make sure the type of work they were
19 describing, just to verify what was going on, so I questioned. But did I
20 ever challenge in the sense of ask them for a deduction; no. I never
21 asked or a deduction or recommended a deduction would have been my
22 role. [sic]

23 (Case No. ER-2010-0355, Vol. 14, Tr. 267, l. 6-15)

1 In the next day of hearings, KCPL's witness was further cross-examined on Schiff
2 expenses:

3 Jaime Ott:

4 Q. Did you ever have a dispute with Schiff Hardin on the amount of
5 work that they were billing to you?

6 KCPL Witness Blanc:

7 A. No. As I said, we had those discussions, but there was never an
8 unresolved issue. I was always comfortable with the explanation of -- or
9 we were comfortable, I should say, the law department, Jerry Reynolds
10 and I were comfortable that they were doing the work they said they were
11 doing and their work was productive. They weren't wasting time doing it.

12 Q. So none of your conversations with Mr. Reynolds or in the law
13 department ever led you to contact somebody at Schiff Hardin to
14 question—

15 A. Not --

16 Q. -- a particular item on the invoice?

17 A. Not that I'm aware of. I never did.

18 (Case No. ER-2010-0355, Vol. 15, Tr. 500, l. 13 to Tr. 501 l. 3.)

19 Jaime Ott:

20 Q. And that's at risk of getting into highly confidential number -- it's
21 not. So -- you have paid over 20 million just for Schiff?

22 KCPL Witness Blanc:

23 A. That's correct. In the broad support for the projects over the past
24 five years, that's correct. And it's less than 1 percent of the project cost.

25 (Case No. ER-2010-0355, Vol. 15, Tr. 503 ll. 1-6.)

26 Commissioner Gunn had several questions for KCPL's policy witness Blanc:

27 Commissioner Gunn:

28 Q. Was there any adjustment to rates to reflect Kansas City rates or
29 were they Chicago rates, do you know?

30 KCPL Witness Blanc:

1 A. I would say they were neither. They were construction expert
2 rates, geographic -- geographically irrelevant.

3 (Case No. ER-2010-0355, Vol.15, Tr. 534, ll. 4-9)

4 Commissioner Gunn:

5 Q. We're talking about \$20 million. Ultimately you guys paid this
6 law firm \$20 million for the services that they were doing?

7 KCPL Witness Blanc:

8 A. Yeah. And --

9 Q. And there was no -- Let me finish the question.

10 A. You bet.

11 Q. There -- there doesn't appear to be any negotiation on rates, there
12 doesn't appear to be any negotiation on volume discount. You knew how
13 long the project was going to last. There had to be a budget put together
14 for what you were going to pay this entity. And you guys just picked who
15 you thought won it. Now, I'm not saying that was a bad choice, but I just
16 want to make it -- asking the clear questions.

17 You did not try to negotiate down rates, you did not try to get other
18 firms that -- in -- and there was no competitive process in order to hire the
19 firms. And so let me -- I'll ask that question. There was no competitive
20 process to hire this firm and there was no appearance to negotiate lower
21 rates based on either geographic location or other competitive factors?

22 A. They're just going to have to parse out what I know and I don't
23 know. I do know there was not an RFP process, but because I wasn't
24 involved directly in hiring them or negotiating, I don't know any
25 discussions around discounted rates. I don't know that. But I do know
26 that they didn't charge us for any of their travel time.

27 (Case No. ER-2010-0355, Vol.15, Tr. 535 l. 7 to Tr. 536, l. 12.)

28 Commissioner Gunn:

29 Q. And there was not a single time entry in that entire \$20 million --
30 or approximately \$20 million that was ever disallowed?

31 KCPL Witness Blanc:

32 A. No. There were ones that arose questions, but those questions
33 were always addressed.

34 (Case No. ER-2010-0355, Vol. 15, Tr. 538, ll. 2-6.)

35

1 Commissioner Gunn:

2 Q. And -- and these are fees that you are -- that are separate from rate
3 case expense. Right? These will be included in project cost? These
4 would not be considered rate case expense. Correct?

5 KCPL Witness Blanc:

6 A. The vast majority. There would be a very small portion that
7 they've done in support of the rate cases, but that would be an extremely
8 small portion of that number.

9 (Case No. ER-2010-0355, Vol. 15, Tr. 539, ll. 2-9.)

10 Throughout the cross-examination, KCPL's witness could not identify any
11 adjustments KCPL made to any of the legal billings of \$20 million of
12 Schiff Hardin expenses. There was no objection to bills, no billing
13 disputes, and no negotiation of fees.

14 Clearly, in comparison to the approximately \$20 million Schiff Hardin charged to the
15 Iatan Construction Project, the \$3.5 million charged to rate case expense was not "an extremely
16 small portion of that number."

17 In its 2010 *Rate Case Report and Order*, the Commission stated on page 169-170:

18 Although the Commission acknowledges the complexity and significance
19 of these rate cases, the Commission is concerned with the continued
20 increase of rate case expenses. It is undisputable that shareholders benefit
21 from hiring the very best advocates and experts. This clearly aids in their
22 ability to argue for a higher return on equity as well as the recovery of a
23 greater percentage of costs. Yet, given the magnitude of these expenses
24 (\$7.7 million dollars), with substantially more to be deferred to the next
25 case, the Commission would expect to see some evidence that KCP&L
26 and GMO had engaged in cost containment. Mr. Blanc, however, testified
27 that of the invoices received for legal fees and expert consultants not one
28 was questioned by the Companies.

29 Despite this admonition by the Commission in the last rate case, KCPL continues to fail
30 to closely manage its rate case expenses. The Commission, in its Report and Order, clearly
31 expected KCPL to engage in cost containment and management of rate case expenses. However,
32 Staff has yet to see, other than \$13,621 in client adjustments and discounts in the invoices above,
33 of any kind of management of rate case expenses. In response to Staff's Data Request 128, Case
34 No. ER-2012-0174, KCPL could not identify any billing adjustment by a legal vendor. Staff's
35 request with KCPL's response follows:

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33

Question No.: 0128

Provide each and every billing adjustment by a law firm vendor charged to rate case expense in 2009, 2010, and 2011.

Response:

Discounts may be noted on bills previously produced to Staff that fall within the aforementioned timeframe in Case Nos. ER-2010-0355, ER-2010-0356, and EO-2010-0259. See list of prior DRs below containing that information:

EO-2010-0259	Data Request 415.1RS
EO-2010-0259	Data Request 415.1RS2
ER-2010-0355	Data Request 141.2
ER-2010-0355	Data Request 141.3S
ER-2010-0355	Data Request 141.3RS
ER-2010-0355	Data Request 593S
ER-2010-0356	Data Request 154.2S
ER-2010-0356	Data Request 154.2TS

For bills that have not been previously produced to Staff there are no adjustments made by law firm vendors.

The Company is unaware of any adjustments made by law firm vendors prior to receipt. It is customary practice for law firm vendors to perform an internal review of invoices prior to submission to the client. Therefore, adjustments may have been made without the Company's knowledge prior to delivery to the Company for review and payment.

KCPL's reliance on legal vendors to manage the expenses billed by those vendors is not in keeping with the direction the Commission provided to KCPL in the 2010 rate case. Staff is aware of the pendency of Case No. AW-2011-0330 (*In the Matter of a Working File to Consider Changes to Commission Rules and Practices Regarding Rate Case Expense*), and ongoing consideration of rate case expense management. Staff, however, is not recommending a specific disallowance solely as a consequence of KCPL's failure to challenge legal invoices.

Qualifying Advanced Coal Project Credit Litigation Expenses charged to Rate Case Expense

KCPL incurred external legal fees in the 2010 Rate Case from vendor SNR Denton in its defense of the issues surrounding the Qualifying Advanced Coal Project Credit. KCPL chose not to employ in-house counsel already in its revenue requirement to litigate this issue. The

1 matter of the Qualifying Advanced Coal Project Credit is discussed in more detail in this report
2 by Staff Expert Cary G. Featherstone in that section. KCPL Missouri ratepayers should not bear
3 the incremental costs related to KCPL's defense of its imprudent decisions related to this issue.
4 Staff has identified the specific hours related to the research, litigation, and briefing of the
5 Qualifying Advanced Coal Project Credit issue before the Commission. Staff removed the
6 attorney fees for these hours from KCPL's rate case expense as they are a direct result of
7 KCPL's imprudent decisions. Staff removed these fees from the post true-up rate case expense
8 from the 2010 Rate Case. If the Commission does not adopt Staff's normalized level of rate case
9 expense, Staff recommends removal of any similar fees from the 2012 Rate Case expense and
10 from any amounts deferred for future recovery. The rate case expense legal fees from vendor
11 SNR Denton charged to KCPL and GMO specifically related to the Qualifying Advanced Coal
12 Project Credit are shown in the below table:

KCPL – MO	\$15,365
GMO – MPS	\$5,506
Total	\$20,871

14
15 In the current 2012 Rate Case, KCPL has hired PricewaterhouseCoopers, LLP (PwC) as a
16 consultant and witness on its Qualifying Advanced Coal Project Credit issues. According to
17 KCPL's response to Staff Data Request 299 in Case No. ER-2012-0174, through May 2012,
18 KCPL incurred \$20,700 of expenses related to its witness Salvatore Montalbano of PwC and
19 another PwC employee, Bob Hriszko, both of which are billed to KCPL at \$600 per hour, the
20 highest hourly rate of any consultant or attorney utilized by KCPL or GMO in the current rate
21 cases. Mr. Montalbano's fees were charged directly to rate case expense.

22 Because KCPL incurred these expenses only because its employees neither informed
23 GMO of nor sought for GMO a portion of the tax credit before KPCL's and GMO's 2010 rate
24 cases, Staff disallowed from KCPL's rate case expense the expenses KCPL has incurred by
25 retaining PwC for its Qualifying Advanced Coal Project Credit issues, including
26 Mr. Montalbano's and Mr. Hriszko's fees. If the Commission does not adopt Staff's normalized
27 level of rate case expense, Staff recommends disallowing these PwC expenses not only from
28 rate case expense through the true-up, but also any post-true up rate case expenses deferred for
29 future recovery.

1 The Communication Counsel of America and NextSource

2 The Commission, in its 2010 Rate Case *Report and Order* was presented with and
3 ordered adjustments to rate case expense concerning NextSource expenses and The
4 Communication Counsel of America (CCA) expenses. Particularly, the Commission found on
5 Page 171 of its *Report and Order* that the services provided could have been performed by in-
6 house attorneys:

7 ...The CCA provided witness development and coaching services, routine
8 tasks typically performed by retained counsel, internal or otherwise. The
9 KCC also disallowed similar expenses as unjust and unreasonable. The
10 Commission determines that the CCA expense should be disallowed as
11 duplicative of other services that were performed or should have been
12 performed [sic] KCPL's and GMO's attorneys.

13 Staff has identified an additional \$29,148 of rate case expenses KCPL has paid to The
14 Communication Counsel of America. Staff has made an adjustment to disallow these rate case
15 expenses related to the 2010 Rate Case.

16

The Communication Counsel of America Post-True-Up Expenses	
KCPL-MO	\$13,408
GMO-MPS	\$12,242
GMO-L&P	\$3,498
Total	\$29,148

17
18 KCPL did not defer additional NextSource expenses that were at issue in the 2010 Rate
19 Case to its post-true-up rate case expenses. KCPL removed these expenses from the test year in
20 its Adjustment CS-11, and Staff has reflected these adjustments in its cost of service.

21 Rate Case Expense Recommendation

22 Staff is maintaining the treatment of 2010 Rate Case expenses incurred prior to
23 December 31, 2010 and the post-true-up 2010 Rate Case expenses pursuant to the Commission's
24 *Report and Order* in those cases. The three year amortization of rate case expense as ordered
25 totals \$1,294,629.

26 The Commission, in its *Report and Order*, authorized KCPL to defer in a regulatory asset
27 the rate case expenses for future recovery subject to review for prudence and reasonableness.
28 While it may have been prudent for KCPL to retain a seemingly unlimited amount of litigation

1 support during the proceedings of the 2010 Rate Cases, it would be wholly unreasonable to pass
 2 on the entire amount of rate case expenses to Missouri ratepayers. Staff's adjustments and totals
 3 below detail the amount of 2010 Rate Case expenses Staff is recommending the Commission
 4 include in KCPL's cost of service and revenue requirement for setting rates in this case. In
 5 maintaining the defer and amortize approach of rate case expense through the KCPL Regulatory
 6 Plan, Staff recommends a three-year amortization of 2010 post true up rate case expenses, net of
 7 Staff's adjustments. As a result of the "defer and amortize" accounting method, Staff
 8 recommends KCPL's over-collection of 2009 Rate Case expenses reduce the amount of 2010
 9 Rate Case post-true-up rate case expenses to be amortized. At the time of the expected effective
 10 date of rates in this case, the over-collection related to KCPL's 2009 Rate Case expense will be
 11 \$740,910. Utilizing this over-collection, the Empire sharing of expenses, and Staff's
 12 recommended adjustments, the net deferred costs are \$792,787, or \$264,262 over three years:

Summary of Rate Case Expenses reflected in Staff's Cost of Service		
KCPL - MO Only Rate Case Expenses	2010 Rate Case ER- 2010-0355, Dec. 31 Cutoff	2010 Rate Case Post True Up expenses
Deferred Costs	6,079,515	
Transfer of Post-True-Up Costs from 2010 Case No. ER-2010-0355	(2,605,670)	2,605,670
Decrease due to over collection of 2007 Case No. ER-2007-0291	(464,864)	
Decrease due to over collection of 2009 Case No. ER-2009-0089 (through January 2013)		(740,910)
Transfer of Post-True-Up Costs from 2009 Case No. ER-2009-0089	1,119,581	
Reduction of Communication Counsel of America expenses, Commission Order 2010 Case	(17,737)	
Reduction of NextSource Expenses, Commission Order 2010 Case	(226,937)	
Staff Adjustment of Communication Counsel of America Expenses		(13,408)
Staff Adjustment SNR Denton Fees		(15,365)
Staff Adjustment Schiff Hardin Fees		(392,727)
Net Reduction from Empire Sharing of Rate Case Expenses		(650,473)
Total Net Deferred Costs	3,883,888	792,787
Amortization Period	3	3
Annual Amortization Amount	\$ 1,294,629	\$264,262

14
 15 For rate case expenses incurred in the 2012 Rate Cases, Staff is recommending a
 16 normalized level utilizing a three year average of rate case expenses using the 2006 Rate Case,

1 2007 Rate Case, and 2009 Rate Case expenses. Staff does not recommend using the 2010 rate
2 case expenses in an average due to the unique issues in that case, namely Iatan prudence. As can
3 be seen, the 2010 Rate Case expenses were by far the highest during KCPL's Regulatory Plan
4 rate cases. Staff recommends a normalized level of \$1,429,083. This amount is an average of
5 rate case expenses for KCPL's 2006, 2007, and 2009 Rate Cases. Staff recommends recovery of
6 this amount over three years, or \$476,361 per year. This amount would not be subject to true-up
7 for actual expense incurred, or any over or under-recovery recognized.

8 Staff Adjustment E-218.6 removes the test year amortization of 2009 Rate Case expenses
9 as that amortization ended August 2011.

10 Staff Adjustments E-218.7 and E-218.8 annualizes the test year amortization of 2010
11 Rate Case expenses.

12 Staff Adjustment E-218.9 amortizes the 2010 Rate Case post-true-up rate case expenses
13 and the 2012 Rate Case expenses as of March 31, 2012 over a 3 (three) year period.

14 *Staff Expert/Witness: Keith Majors*

15 **17. Arbitration Expenses Concerning The Empire District Electric**
16 **Company**

17 On October 5, 2010, The Empire District Electric Company ("Empire") filed a
18 Demand for Arbitration against KCPL concerning ** _____
19 _____

20 _____ ** The specific conflict is described as follows in Empire's Demand for
21 Arbitration obtained in KCPL's response to Staff's DR No. 0215 in Case No. ER-2012-0174:

22 ** _____
23 _____
24 _____
25 _____
26 _____
27 _____
28 _____
29 _____
30 _____
31 _____
32 _____
33 _____

1
2
3
4
5
6
7
8

_____ **

9 The origin of Empire's dispute with KCPL is described as follows in ** _____
10 _____ **

11 pages 3-4, also provided in KCPL's response to Staff's DR No. 0215:

12 ** _____
13 _____
14 _____
15 _____
16 _____
17 _____
18 _____

19 _____
20 _____
21 _____
22 _____
23 _____
24 _____
25 _____
26 _____
27 _____
28 _____ **

29 This is an issue and subsequent matter of arbitration that KCPL created by ** _____
30 _____

31 _____ ** According to KCPL's response to Staff DR
32 No. 215.1, _____
33

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32

_____**

For the terms of the settlement agreement, please see response to DR0215.3.

** _____

_____**

At the time of this filing, Staff has pending discovery concerning the accounting and ratemaking treatment of this settlement. To the extent that KCPL has included this settlement in its test year cost of service in this case, Staff recommends that the effect of the settlement be removed as it is non-recurring, no benefit to ratepayers, and the result of a KCPL-created legal dispute.

KCPL incurred a total of ** _____ ** in legal expenses related to this arbitration, ** _____ ** of which is in KCPL's test year cost of service.

The Commission in Case No. ER-2010-0355 determined the recovery from KCPL's ratepayers of similar expenses concerning another matter of arbitration between KCPL and Empire over the Advanced Coal Tax Credit on page 174 of its April 12, 2011 Report and Order:

.... If the Commission grants KCP&L recovery of these legal fees, the Commission will be encouraging this utility to engage improper actions.

The Commission determines that the arbitration expenses KCP&L has incurred in defending itself for its imprudent acts are disallowed from KCP&L's cost of service for setting rates.

Both of these arbitration proceedings were between KCPL and Empire, ** _____

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29

** Additionally, these legal expenses are not ongoing, did not benefit ratepayers, and are not representative of KCPL's ongoing costs. Therefore, they should not be borne by KCPL's ratepayers. Staff is recommending an adjustment to remove them from its determination of KCPL's cost of service in this case.

Adjustment E-204.2 removes the test year expenses related to this arbitration from KCPL's cost of service.

Staff Expert/Witness: Keith Majors

18. Public Service Commission Assessment Fee / FERC Assessment Fee

The Public Service Commission assessments ("PSC Assessment") are 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. The PSC Assessment is charged to regulated utilities in Missouri. KCPL's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2012) 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 also chose to update the Company FERC Assessment paid to represent 12 months ending March 31, 2012. FERC is the Federal Energy Regulatory Commission, and they have a separate assessment to be paid by all regulated utilities, handled in similar fashion to the aforementioned PSC Assessment. Adjustment E-217.1 and FERC Adjustment E-214.1.

Staff Expert/Witness: Bret G. Prenger

19. Customer Deposits – Interest Expense

Staff's recommended treatment of customer deposits' interest expense 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, calculated by multiplying the most current customer deposits balance that KCPL included in its rate base to 4.25% interest. An amount of interest relating to customer

1 deposits has been included as adjustment to the Income Statement - Schedule 9. Staff calculated
2 the interest for customer deposits consistent with the level of customer deposits reflected in the
3 Rate Base -- Schedule 2 (see discussion in the Rate Base section of this report for customer
4 deposits included in rate base). For this calculation, Staff used the customer deposit balance to be
5 included in rate base, and then multiplied that number by the most current prime interest rate
6 published in the Wall Street Journal (3.25) plus 1%, for a total of 4.25%. Adjustment E-171.1.
7 The Commission should base its awarded revenue requirement on Staff's recommended amount
8 of interest relating to customer deposits by including the customer deposit interest expense
9 amount calculated by Staff as an expense adjustment to KCPL's income statement.

10 *Staff Expert/Witness: Patricia Gaskins*

11 **20. Depreciation - Clearing**

12 During the test year, KCPL included depreciation for transportation equipment that was
13 charged to expense through a clearing account. Staff made an adjustment to remove the
14 depreciation amount booked to the clearing account. Adjustment E-231.1.

15 *Staff Expert/Witness: Patricia Gaskins*

16 **21. Economic Relief Pilot Program**

17 KCPL's Economic Relief Pilot Program ("ERPP" or "program") was approved by the
18 Commission in Case No. ER-2009-0089 as part of a Non-Unanimous Stipulation and Agreement
19 ("Agreement"). The ERPP commenced on September 1, 2009 as a three-year pilot program
20 designed to deliver energy affordability to KCPL's qualifying lower-income residential
21 customers through the application of a "fixed credit," thus allowing those participants to make
22 full and timely payments on their monthly bills. The program is scheduled to end
23 September 1, 2012. As set out in the Agreement, the ERPP provides up to 1,000 participants a
24 monthly "fixed credit" not to exceed \$50 per month, as long as the participant continues to meet
25 the ERPP eligibility requirements and reapplies to the program annually. The ERPP tariff sheet
26 that took effect September 1, 2009 states that annual ratepayer funding for the ERPP is matched
27 dollar for dollar by KCPL.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32

Issue

KCPL is recommending the expansion of the existing program, from 1,000 participants to 2,500 participants, based on an expectation of a positive evaluation of the program. In addition, KCPL is also recommending that the program funding be changed from 50% ratepayer funded and 50% KCPL contribution to 100% ratepayer funded. Staff's initial concern with KCPL's recommendation is that it is based on the unknown.

Analysis

A comprehensive, independent evaluation of the ERPP is required before considering sustainability, expansion or modification, and alternative funding of the program. Direct testimony provided by KCPL's witness Jim Alberts indicates KCPL acquired a third party evaluator, True North Market Insights, LLC, to evaluate the program. KCPL obtained the third party evaluator as recommended by Staff witness Gay Fred in Staff's Cost of Service Report in Case No. ER-2010-0355. The purpose of the third party evaluation is to address all aspects of the program for weaknesses, strengths and improvement opportunities. Mr. Alberts' direct testimony states that KCPL will provide complete evaluation results by the end of 2nd quarter 2012 in a report by KCPL. Additionally, Mr. Alberts advises that Staff, and the other parties in the advisory group, will receive the complete evaluation. However, to date, Staff has not received any report containing an evaluation of the ERPP, which is critical before considering program sustainability, expansion or modification, and alternative funding source.

Recommendation

Staff recommends the ERPP remain a pilot program, maintaining currently authorized participation levels, current program terms, and that program funding of 50% ratepayer funded and 50% KCPL contribution remain unchanged at this time.

Accounting Treatment

Staff's recommended treatment of the ERPP is to include the costs KCPL has incurred during the period of December 31, 2010 through March 31, 2012 (as explained below) and an ongoing level of expense based on the parameters established in the Stipulation and Agreement in Case No ER-2009-0089. According to the Stipulation and Agreement,

The Non-Utility Signatories agree that the Company can defer 50% of the ERPP costs in a regulatory asset until the next KCP&L rate case, with cost recovery to be determined at that time. The remaining 50% of such cost will be borne by the Company's shareholders.

1 Staff made an adjustment to reflect a three year amortization of deferred ERPP costs for the
2 period December 31, 2010 through March 31, 2012. In addition, Staff included an ongoing level
3 of expenses represented by the costs KCPL incurred related to the ERPP during the 12-month
4 period ended September 30, 2011; however, Staff's inclusion of this amount is specifically
5 predicated upon KCPL continuing to incur ERPP costs in the future at twice the level Staff has
6 included in KCPL's revenue requirement, i.e., that KCPL's shareholders continue to fund at least
7 the same level of ERPP costs that Staff has included in KCPL's revenue requirement.

8 *Staff Experts/Witnesses: Contessa Poole-King and Karen Lyons*

9 **22. Low-Income Weatherization Program**

10 The funding for the KCPL Low-Income Weatherization Program was authorized as an
11 expense to be included in rates in the Commission's *Report and Order* ("Order") in the last rate
12 case, Case No. ER-2010-0355⁸⁵. In this case Staff recommends the Commission Order:

- 13 1) KCPL low-income weatherization funds collected from customers but
14 not utilized by the Weatherization Agencies in the previous years of
15 2010 ** _____ **, 2011 ** _____ **, 2012 and in all
16 subsequent years, be made available to the Weatherization Agencies in
17 KCPL's service territory for future use;
- 18 2) KCPL continue to collect \$573,888 for low-income weatherization in
19 rates annually;
- 20 3) KCPL consult the KCP&L DSM Advisory Group (DSMAG) on the
21 allocation and distribution of low-income weatherization funds; and
- 22 4) That KCPL provide quarterly reports to the DSMAG on the allocation
23 and distribution of funds to the KCPL Weatherization Agencies.
- 24 5) That KCPL file tariff sheets that revise Tariff Sheet Nos. 43H, 43I,
25 43I.1 and 43I.2 to comply with the Order in from this case.

26 There are specific programs designed to help low-income customers with energy
27 conservation. Low-income consumers often live in housing that is energy inefficient with

⁸⁵ *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Continue the Implementation of its Regulatory Plan*, Issued April 12, 2011, Effective Date April 22, 2011, pp. 175-182.

1 substandard insulation and other deficiencies. These customers would benefit from building-
2 shell energy conservation measures such as weatherization or energy efficient appliances. KCPL
3 and its customers benefit from the low-income weatherization program through the reduction in
4 the expenses associated with arrearages in billing and shutoffs which occur in greater proportions
5 among low-income customers.

6 The Missouri Low-Income Weatherization Assistance Program (“Weatherization
7 Program”) which is federally, state, and utility funded is administered by the Missouri
8 Department of Natural Resources (MDNR). The Missouri Weatherization Program is
9 administered locally by Community Action Agencies or other local agencies (“Weatherization
10 Agencies”). The KCPL Weatherization Program provides funds for weatherization of KCPL’s
11 low-income customers’ homes in KCPL’s service area. For the KCPL Weatherization Program,
12 KCPL administers funds at the local level for weatherization of its qualified low-income
13 customers which is performed by the Kansas City Housing and Community Development
14 Department (KCHCDD), the West Central Missouri Community Action Agency (WCMCAA),
15 the Missouri Valley Community Action Agency (MVCAA), and the Central Missouri
16 Community Action Agency (CMCAA). These Weatherization Agencies, the authorized funding
17 and funding provided are listed in Appendix 3, Schedule HEW-1. In addition, the areas served
18 by all the MDNR Weatherization Agencies in Missouri, with those eligible for funds from KCPL
19 annotated, are shown in Appendix 3, Schedule HEW-2.

20 The federal government, through the American Recovery and Reinvestment Act (ARRA)
21 provided special funding of \$128 million for the Missouri Weatherization Program for the period
22 of April 2009 – March 2012 (“ARRA Period”). The ARRA provided an average of \$6,500 of
23 weatherization for households with income at 200% or less of the Federal Policy Guidelines. In
24 the three year period prior to the ARRA (2006-2008) federal funding for the Missouri
25 Weatherization Program was approximately \$18 million and the average amount per household
26 was \$3,000. The amount of weatherization funding increased from about \$3,000 to an average
27 of \$6,500 per household. Some Weatherization Agencies have already utilized all of the ARRA
28 funding allocated to them while others are making a concerted effort to utilize the ARRA
29 funding before the December 2012 deadline for utilizing the funds.

30 In addition to the amount of money provided through ARRA, in KCPL’s last rate case,
31 KCPL was authorized to continue to contribute \$573,888 annually to the Weatherization

1 Agencies for the weatherization of qualifying customers' homes, and to recover this amount in
2 rates.. No specific allocation of funds to the Weatherization Agencies was in the Order.
3 According to *Low Income Weatherization Program Status Reports*, submitted to the Commission
4 April 13, 2012, as shown on the attached spreadsheet, *Low-Income Weatherization Program*,
5 (Appendix 3, Schedule HEW-1), KCPL provided ** _____ ** to the four weatherization
6 agencies in its service area in 2011. This is ** ____ **⁸⁶ of the funds collected in rates for
7 weatherization. This under-utilization of funds is likely due to the Weatherization Agencies'
8 focus on using the ARRA funding and restrictions on ARRA funds being combined with utility
9 funds.

10 KCP&L provided *Staff Survey Results* from an informal survey of the weatherization
11 agencies they utilize in the KCPL and GMO weatherization programs at the DSM Advisory
12 Group meeting January 19, 2012. The weatherization agencies responses were generally
13 favorable but the weatherization agencies were not asked if they could use more funding,
14 although one agency commented that they could use more funding⁸⁷.

15 It is Staff's position that the KCPL annual low-income weatherization funding of
16 \$573,888 for the KCPL Weatherization Agencies, should be continued. However, as a condition
17 to KCPL continuing to collect this amount in rates, Staff also recommends that the Commission
18 order that KCPL carry over the unused funds from 2010, 2011, 2012, and all subsequent years,
19 and that such funds be made available solely for the KCPL Weatherization Agencies for low-
20 income weatherization funding; and that KCPL change its method of distributing the funds to the
21 Weatherization Agencies. Staff recommends a change from the current monthly reimbursement
22 funding. In order to increase the utilization of the funds for low income weatherization, Staff
23 recommends the Commission order KCPL to provide half of the annual funding to the
24 Weatherization Agencies at the start of the program year and then dispense additional funds to
25 the Weatherization Agencies as the initial funds are utilized.

26 Staff recommends that the Commission order KCPL to provide monthly reports to the
27 DSMAG on low income weatherization funding and expenditures and submit the reports as non-
28 case related submissions in EFIS. The DSMAG should work with KCPL to review the
29 allocation and utilization of funds by the Weatherization Agencies to determine if any

⁸⁶ *KCP&L Low Income Weatherization Program Status Reports*, submitted to the PSC, April 13, 2012.

⁸⁷ *Survey Question*, KCP&L, document provided at KCP&L DSM Advisory Group meeting, January 19, 2012.

1 adjustments are needed. This review in the way funds are disbursed and utilized will have the
2 goal of a higher utilization of funds by the KCPL Weatherization Agencies. As part of the true
3 up audit, Staff will continue to examine the Low Income Weatherization Program through
4 August 31, 2012 and recommend an adjustment as needed.

5 Subsequent to Case No. ER-2010-0355 KCPL did not file tariff sheets to revise sheet
6 numbers 43H-43I.2 to comply with the Commission's Order regarding the Low Income
7 Weatherization Program. Therefore, Staff recommends that KCPL file tariff sheets that revise
8 Tariff Sheet Nos. 43H, 43I, 43I.1 and 43I.2 to comply with the Commission's order in this case.

9 *Staff Expert/Witness: Henry Warren*

10 **23. SPP Administrative (Schedule 1-A) Fees**

11 As noted in KCPL's direct testimony, the Southwest Power Pool, Inc. (SPP) is a not-for-
12 profit, regional transmission organization (RTO) entity which maintains functional control over
13 the transmission assets of its members and provides transmission services through its Federal
14 Energy Regulatory Commission (FERC) approved open access transmission tariff (OATT).
15 SPP's costs must be recovered from its users (transmission customers). Consequently, as a
16 member of SPP, KCPL pays SPP an administration charge for performing transmission functions
17 on its behalf. Staff adjustments annualize SPP administration charges to Accounts 561
18 (Adjustment E-122.2) and 575 (Adjustment E-129.1) through March 31, 2012.

19 Under its OATT, the SPP establishes a rate for its administration charge annually that
20 enables it to recover 100% of its total annual costs for RTO functions, subject to a rate cap.
21 SPP's administration charge is set each year based on projected costs and revenues for that year.
22 The rate cap serves as a limit on the annual administration charge in order to provide SPP
23 customers a level of certainty and predictability regarding SPP's year-to-year administrative
24 costs.

25 On October 25, 2011 at its Board of Directors/Members Committee meeting at the
26 Eldorado Hotel & Spa, Santa Fe, New Mexico, the SPP Board of Directors approved the SPP
27 Finance Committee's recommendation that the Board of Directors establish an assessment rate
28 and tariff administrative fee (schedule 1-A) of \$.255 per MWh beginning January 1, 2012.
29 According to SPP meeting minutes the SPP's cash forecast indicated that a rate of \$.255 per
30 MWh was sufficient to fully fund SPP's operations during the 2012 year with projected increases

1 to \$.280 per MWh in 2013 and \$.30 per MWh in 2014. The Staff's annualized amount of SPP
2 Administrative fees in this case was based on the January 2012 rate of \$.255 per MWh.

3 The SPP's 2012 administrative fee of \$.255 per MWh is based on a SPP net revenue
4 requirement (NRR) of \$89,560,000, which is an approximately 14 percent increase from its 2011
5 budgeted NRR of \$78,638,000. According to SPP documents, the primary driver of this increase
6 is expected additional salaries and benefits for the Integrated Marketplace development. The
7 2012 budgeted NRR of \$89,560,000 divided by SPP's projected billing determinants of
8 353,453,000 MWh, results in a calculated administrative cost of \$.253 per MWh, but SPP
9 management recommended an administrative fee based on a NRR of \$90,130,515, or \$570,000
10 over budgeted cost requirements.

11 The Staff's March 2012 annualized SPP administration fees included in its revenue
12 requirement proposal for KCPL total \$7,506,852, compared to test year costs of \$6,869,414.
13 This reflects an annual increase of \$637,437, or 9.3%. Included in the annualized amount in
14 Account 561 are NERC fees of \$953,070, long-term reliability, planning and standards
15 development services allocation of \$524,303, and scheduling, system control and dispatching
16 services allocation of \$3,211,353. SPP Administration fees included in Account 575 include a
17 \$2,818,126 allocation to market facilitation, monitoring and compliance services. The Staff's
18 adjustments are reflected in Staff Adjustments E-123 and E-130.

19 *Staff Expert/Witness: Charles R. Hyneman*

20 **24. Account 565 Transmission Expense**

21 KCPL charges transmission expense to Account 565 Transmission of Electricity by
22 Others. In his direct testimony at page 9 KCPL witness John R. Carlson noted that SPP
23 transmission costs allocated to KCPL have been rising, and projections from SPP show that these
24 expenses will continue to increase through 2017. The Staff performed an analysis that supports
25 this conclusion. The chart below reflects a summary of a five-year analysis of Account 565 and
26 shows that KCPL's transmission costs have been increasing significantly over the past few years,
27 especially in 2010 and 2011. KCPL's projected transmission expense based on an annualization
28 of the per book amounts expensed in the first quarter of 2012 is \$20,166,464. In its direct filing
29 the Staff made an adjustment (E-127) to increase test year Account 565 balance of \$17,847,014
30 to a 2012 annualized level of \$20,166,464 based on an annualization for actual incurred costs

1 booked in the first quarter of 2012. The Staff plans to review this adjustment for reasonableness
2 in its true-up audit based on updated events and cost information.

3

	Acct 565	Change
2008	\$11,119,963	-
2009	\$12,349,274	11%
2010	\$15,022,325	22%
2011	\$18,811,254	25%
Projected 2012	\$20,166,464	7%

4

5 *Staff Expert/Witness: Charles R. Hyneman*

6 **X. Depreciation**

7 **A. Recommendations**

- 8 1. Staff recommends the Commission order KCPL to continue to use the
9 depreciation rates ordered in the prior rate case Case No. ER-2010-
10 0355 and the new account depreciation rates ordered in Depreciation
11 Authority Order Case No. EO-2012-0340, for KCPL, with the
12 exception of the method of computation of monthly depreciation
13 accruals for select general plant accounts using the experimental
14 vintage amortized method.
- 15 2. Staff recommends that the experimental switch of select general plant
16 accounts to a vintage amortization method allowed in prior rate case
17 Case No. ER-2010-0355 not be allowed to be put in place on a
18 permanent basis, and these accounts revert back to a depreciation
19 accrual method, including booking plant retirements as they actually
20 occurred during the vintage amortization trial period.
- 21 3. Staff recommends the Commission order KCPL to make adjustments in
22 general plant reserves accounts of a total of \$6,483,406 to address an
23 under recovery of plant, (deficiency in depreciation reserves). Staff is
24 recommending two adjustments:
- 25 • An adjustment, (increase of reserves) of \$4,844,004 related to
26 early retirements of plant and equipment related to KCPL and
27 former Aquila facilities consolidations and relocations
28 attributable to the Aquila acquisition.
 - 29 • A transfer of \$1,639,402 from transmission plant reserves (that
30 are collectively over accumulated in excess of \$30,000,000) to
31 distribute within general plant accounts 390, 391, 393, 394, 395,
32 397, and 398.

- 1 4. Staff recommends the transfer of accumulated reserves between
2 accounts within the general plant accounts, such that in conjunction
3 with the \$6,483,406 from recommendation 3 above, result in a
4 rebalancing of reserves in the general plant accounts to remove over
5 and under recovery in accounts 390, 391, 393, 394, 395, 397, and 398.
6 A table below shows the amounts associated with each account to
7 transfer, Table: **Amounts To Transfer**.
- 8 5. Staff recommends the Commission order KCPL to conduct a physical
9 inventory of plant in service in the general plant accounts for all non
10 production facility locations, submitting the results of this physical
11 inventory with the next depreciation study due the earlier of June 30,
12 2015 or June 30, 2013 with a rate case, including a record of all plant
13 transaction activity conducted as a result of this physical inventory.
- 14 6. Staff recommends the Commission direct KCPL to complete by June
15 30, 2013 the studies described in Paragraph 10 of the *Nonunanimous*
16 *Stipulation and Agreement Regarding Depreciation and Accumulated*
17 *Additional Amortizations*, (“Depreciation Stipulation”) and provide the
18 results as described in the Depreciation Stipulation. Staff requests the
19 Commission direct Staff as to whether it should file a complaint against
20 KCPL for its failure to provide study results as described in the
21 Depreciation Stipulation.

22 **B. Amortization Method:**⁸⁸

23 The Depreciation Stipulation provided that:

24 The Signatories request that the Commission authorize KCPL and GMO
25 to utilize the “Amortization Method” for specified General Plant accounts.
26 The Amortization Method is a straight line method, in that the
27 depreciation starts when the equipment is installed and stops when the
28 equipment value is fully depreciated. For regulatory mass property
29 accounting purposes, all of the additions to an account over a vintage (one
30 year or one month of additions) are depreciated over a set amortization
31 period. For depreciation accounting purposes, all of the equipment in each
32 vintage is retired at the end of the amortization period. No interim
33 retirements are recorded....

34 Staff recommends that the Commission order KCPL to record monthly depreciation
35 accruals based on actual plant in service, using depreciation rate computed from an average
36 service life equivalent to the trial amortization period for each account for accounts 391, 393,
37 394, 395, 397, and 398. Staff included adjustments to plant and reserves in the vintage

⁸⁸ In this context, the term “amortization method,” refers to the same practice as the term “vintage amortization.” Although the Depreciation Stipulation in Case No. ER-2010-0355 used the term “amortization method,” the term “vintage amortization” is more precise, and Staff will use that term in this Report.

1 amortized accounts as a substitute for actual retirements that occurred during this trial period, but
2 were not recorded to the Company books.

3 The vintage amortization method is a simple amortization of investment starting in the
4 year the plant is placed in service. Use of vintage amortization also forces the over or under
5 accumulated reserve in each account to be addressed by either a transfer to other accounts or as a
6 separate amortization. Thus use of the amortization method provides a less precise reflection in
7 rates of the current plant in service, and the act of changing to the amortization method from
8 normal regulatory depreciation typically requires additional rate-making treatment. In order for
9 Staff to have the opportunity to conduct effective regulatory oversight of cost of service, the
10 plant records and retirement rates for actual plant in these accounts must be available for review
11 and study.

12 **C. Reserve Transfers and Reinstatement of Reserves**

13 Under recovery of depreciation reserves may occur due to: 1) the Company failing to
14 properly record depreciation of plant still in service, 2) the depreciation analysis or record of
15 retirement history used for projections was in some way defective, or 3) unexpected events occur
16 resulting in retirements earlier than forecast. Staff undertook a study to analyze the dollars of
17 KCPL's alleged under recovery attributable to each of these causes. The results of that study are
18 attached as Appendix 3, Schedule AWR-1.

19 Staff found the KCPL general plant reserve as currently booked to be under recovered by
20 approximately \$6,483,406. This includes accounts currently using the trial basis vintage
21 amortized method of accrual, plus account 390 (Structures).

22 For general plant account 390, Structures and Improvements, abnormal retirements
23 recorded for facilities abandoned as a result of the consolidations of office and service centers
24 should be addressed in the next depreciation study, with the historical data coded as final versus
25 interim retirements, such that the abnormal retirements are removed from the computations to
26 project future depreciation rates.

27 Staff investigated the historical retirement record itself. For general plant accounts at
28 service facilities, multiple instances of plant and equipment recorded as still in service were
29 identified and confirmed to not be in service. Staff reviewed additions and retirements to the
30 structures account 390 related to building modifications and additions. KCPL stated that near

1 the end of a facility modification project, the property records person(s) and the project
2 management person(s) do a physical walk through and try to identify the items that are now
3 missing or removed from service. Staff contends that this method of identification of retirements
4 has a high probability of introducing errors over multiple years of layered projects if periodic
5 physical inventories are not conducted. Staff's review of company-provided detailed list of plant
6 and equipment in service allowed Staff to easily identify items which Staff doubted would still
7 exist or be in service simply due to the type of item and the vintage. KCPL admitted that the
8 majority of the questionable items were probably not used or useful or still physically present.
9 These discrepancies indicate that KCPL has an audit problem that can only be corrected by the
10 Company conducting a physical inventory. Staff reviewed plant in service records for the general
11 plant accounts at all company locations. The facilities that Staff easily identified questionable
12 booked plant in service were service facilities. For the production facilities, Staff found no
13 questionable booked items by simply looking at plant records. Thus, Staff's recommendation to
14 conduct a physical inventory of general plant is limited to non production facilities.

15 The evidence of poor plant records brings into question not only the accuracy of the plant
16 in service record, but the retirement record used in depreciation studies. At various meetings
17 with KCPL personnel knowledgeable in plant records and the Company history, Staff has asked
18 if and when physical inventories were conducted on plant in service for general plant accounts.
19 KCPL could not recall having conducted physical inventories.

20 The Depreciation Stipulation suggests the transfer dollars from the over-accumulated
21 depreciation reserves in the transmission accounts to the general plant accounts is an appropriate
22 action to address the shortfall , (Staff's shortfall estimate of a total of \$6,483,406), in general
23 plant accounts. However, Staff's study indicated that a major portion, \$4,884,004, of this
24 shortfall in the depreciation in the general plant accounts is a result of the Aquila acquisition;
25 therefore, this portion of the shortfall should be treated as an Aquila acquisition detriment. Staff
26 recommends an adjustment (increase) of reserves in the general plant accounts by \$4,844,004.

27 Staff also reviewed KCPL's GMO's electric utility sale of assets in Colorado on July 14,
28 2008 to Black Hills Corporation. KCPL reported the sale proceeds as a gain in FERC account
29 421.1. Transaction records for this period show no retirements noted as "Sale to Black Hills",
30 only transfers. A transfer transaction results in the removal of only the accumulated depreciation

1 from the reserves which do not leave a deficiency in reserves. This indicates to Staff that the
2 sale to Black Hills is not a direct cause or contributor to general plant reserve deficiencies.

3 **D. Assignment of the contributing sources (causes) of the under recovered amounts**

4 Abnormal and unexpected events are included in KCPL's retirement history. The Aquila
5 acquisition resulted in abnormal and unexpected retirements as a result of office and service center
6 consolidations and relocations. Staff concluded that an under recovery, (deficiency in
7 depreciation reserves), in the general plant accounts for KCPL of \$4,844,004 is associated with
8 the acquisition of Aquila and the resultant closure and consolidation of facilities. Specifically, the
9 1201 Walnut former KCPL's Headquarters, the 801 Charlotte Dispatch Center, and the Marshal
10 Service Center in Marshal, Missouri, resulting in an earlier than expected retirement of large
11 amounts of plant and equipment. Staff recommends that this portion of under recovery be
12 reinstated to reserves as a detriment due to the acquisition of Aquila.

13 In the table below, the Missouri jurisdictional amounts of \$1,008,575 for account 390 and
14 \$3,835,428 amortized accounts, totaling \$4,844,004 represents Staff's estimate of the amount of
15 accumulated reserve under recovery contributed from early retirements as a result of
16 consolidations and relocations attributable to the Aquila acquisition. The years 2008 through 2011
17 include retirements recorded for plant and equipment that was still functionally usable, but no
18 longer used or useful within the new organizational structure. These retirements resulted in a
19 steep increase in retirement rate for general plant accounts. The result is a steep decrease in
20 accumulated depreciation reserves as the original cost of each retirement is deducted from
21 reserves. For retirements earlier than expected the accumulated accrued depreciation for the item
22 is less than the original cost, resulting in a reserve deficit, or under recovery of plant.

23 **Note:** A positive number in these tables represents a shortfall in reserves in
24 these accounts,

25
26
27 *continued on next page*
28
29
30

Breakdown of KCPL Unrecovered Reserves in General Plant

	KCPL \$
Act 390 only (2008)	
Stopped Depreciation	0
Depreciation Mismatch	(6,633,575)
<u>Aquila Acquisition</u>	<u>1,008,575</u>
Account 390 Under Recovery	(5,625,000)
Amortized Accts Only (2011)	
Stopped Depreciation	0
Depreciation Mismatch	8,272,978
<u>Aquila Acquisition</u>	<u>3,835,428</u>
Amortized Accounts Under Recovery	12,108,406
Total Amortized + Act 390	
Summary	
Stopped Depreciation	0
Depreciation Mismatch	1,639,402
<u>Aquila Acquisition</u>	<u>4,844,004</u>
General Plant Under Recovery	6,483,406

1
2
3

Table: Amounts To Transfer

Positive Number = reserve deficit

Account	Juris Unrec 2010
390	(5,625,000)
391	133,299
391.01	40,607
391.02	417,063
393	(12,434)
394	209,873
395	(112,938)
397	11,393,972
397.01	15,916
397.02	2,212
398	<u>34,836</u>
Amortized Tot	12,108,406
Acc 390	<u>(5,625,000)</u>
Total Gen Plant	\$6,483,406

1
2 The \$6,483,406 shortfall is made up by reinstatement from KCPL of \$4,844,004 to
3 reserves and a transfer of \$1,639,402 from transmission account 353 (Station Equipment)
4 reserves. Account 353 shows an over accumulation of reserves in excess of \$10,000,000 in the
5 depreciation study conducted by Staff in the prior rate case, Case No ER-2010-0355.

6 **Derivation of Dollar Amounts**
7 **Amortized Accounts**

8 The Amortized Accounts Under Recovery line shows \$12,108,406. This is the difference
9 at December, 31, 2011 for all KCPL vintage amortized accounts between the sum of all of the
10 vintage amortizations and the Missouri jurisdictional reserves booked in these accounts. The
11 sum of each vintages amortization for this type of depreciation expense accrual may be
12 conducted at any time and compared to booked amounts without conducting a depreciation
13 study. Any deviation in the two, such as from cost of removal or salvage, may be addressed in
14 any rate case. The amount in this rate case, \$12,108,406, to address represents a “stranded”
15 amount carried over from the prior depreciation accrual method, and reflects an under accrual of
16 depreciation. The vintage amortization method will not cover or compensate for booked
17 accumulated depreciation reserves which do not match expected accrued amortization. It is
18 labeled “stranded” because there is no automatic method, such as the use of remaining life
19 depreciation rates, to address these amounts. The above table, Amounts To Transfer, shows the
20 amounts for each account. Note: The reserve deficit is almost exclusively contained in
21 account 397, Communications Equipment. Staff’s assessment of the retirement record shows the
22 cause as the closures and consolidation involving the 1201 Walnut former KCPL’s Headquarters,
23 the 801 Charlotte Dispatch Center, and the Marshal Service Center in Marshal, Missouri
24 resulting in the retirement of large amounts of communications equipment.

25 **Account 390, Structures and Improvements**

26 Account 390 Under Recovery, a negative \$5,625,000, in the above table represents an
27 over recovery in this account. This amount was estimate using the depreciation study results
28 presented by KCPL in the prior rate case, Case No. ER-2010-0355. It is the difference between
29 calculated theoretical reserves and book reserves as of December. 31 2008.

1 **Stopped Depreciation**

2 For KCPL, Staff's investigation of general plant accounts to satisfy the ER-2010-0355
3 Depreciation Stipulation and Agreement study of causes of under recovery of plant, no instances
4 of KCPL prematurely stopping of depreciation were found by Staff.

5 **Depreciation Mismatch**

6 Depreciation mismatch is used as a name to indicate under or over recovery of plant
7 attributed to normally expected drift over time between forecast (ordered depreciation rate) and
8 actual retirement rate. The table amounts shown were derived by difference, that is, whatever
9 still exists after other causes are accounted for. In the above table, this is the \$ (6,633,575) for
10 account 390 and \$8,272,978 for amortized accounts, totaling \$1,639,402. The actual retirement
11 history has essentially been lost. Only an indirect estimate method is available.

12 **Aquila Acquisition**

13 The portion of the under recovery assigned as Aquila Acquisition in the above table is the
14 Missouri jurisdictional amount Staff derived from the analysis of elevated retirement rates versus
15 normal expected retirement rates for the 4 year period subsequent to the Aquila acquisition, and
16 attributed to closures, relocations and consolidations of offices and service centers within KCPL.

17 **Accounts Not Included in the Study**

18 Of all the general plant accounts, Staff did not include transportation equipment
19 (account 392), or power operated equipment (account 396) within this Stipulation related study.
20 The reasons are: Depreciation studies for the last case found overall accumulated reserves for
21 these accounts at reasonable levels for the age of the equipment at that time. These accounts
22 were not switched to the general plant amortization method. And typical equipment in these
23 accounts are large items with maintenance records and vehicle registration requirements etc.
24 which although they migrate around the Company, are not easily overlooked when retirements
25 should be booked.

26 **E. Regulatory Depreciation**

27 Staff does not recommend any change in currently ordered depreciation rates, other than
28 to return the general plant accounts subject to the Amortization Method trial period be returned
29 to a traditional depreciation accrual method. The depreciation rates remain unchanged from

1 those in effect prior to Case No. ER-2010-0355, and are the same depreciation rates ordered in
2 that rate case, only the computation method of the monthly accrual changes.

3 *Staff Expert/Witness: Arthur W. Rice*

4 **XI. Regulatory Plan Additional Amortizations**

5 The Experimental Alternative Regulatory Plan Additional Amortizations were authorized
6 by the Commission in Case No. EO-2005-0329. The Commission approved a unique regulatory
7 approach presented in a Stipulation and Agreement signed by KCPL and numerous parties,
8 including The Office of the Public Counsel and Staff, which allowed KCPL certain
9 accommodations to traditional ratemaking for pursuing what KCPL referred to as its
10 "Comprehensive Energy Plan" (CEP). This experimental alternative regulatory plan (the
11 "Regulatory Plan") resulted, among other things, in fostering the construction of Iatan 2. KCPL
12 recently completed construction of this 850 megawatt pulverized coal-fired supercritical steam
13 electricity generating unit which KCPL declared met the in-service criteria of the Regulatory
14 Plan on August 26, 2010. Iatan Unit 2 is located on the same site where KCPL completed the
15 original Iatan 1 in May 1980.

16 In the CEP, KCPL also committed to make significant environmental plant additions to
17 its LaCygne 1 and to Iatan 1, and to construct a 100 megawatts of wind generation, which it did
18 with its Spearville Wind Farm in western Kansas which was included in rates in 2007 in Case
19 No. ER-2006-0314. The first phase of the environmental plant enhancements at LaCygne 1 was
20 completed in 2007. KCPL's Missouri jurisdictional portion of the LaCygne I investment was
21 included in KCPL's rate base in KCPL's 2007 rate case, Case No. ER-2007-0291. KCPL
22 completed the extensive environmental additions to Iatan 1 in the first quarter of 2009. The
23 Missouri jurisdictional part of KCPL's investment in those additions was primarily included in
24 KCPL's rate base in KCPL's 2009 rate case (Case No. ER-2009-0089). KCPL completed
25 Iatan 2 in August 2010 and the costs for this power plant were included in KCPL's last rate case
26 (Case No. ER-2010-0355).

27 The Additional Amortizations were an accommodation to traditional ratemaking to assist
28 KCPL to maintain certain financial ratios. KCPL was permitted to calculate its revenue
29 requirement using these cash flow ratios or financial benchmarks in order to provide KCPL with
30 sufficient cash (earnings) to maintain certain investment grade financial measures. In the

1 Regulatory Plan, the signatory parties agreed to allow KCPL to include amounts in its rate cases
 2 referred to as "additional amortizations" which had the effect of increasing KCPL's cash flow
 3 through increased retail revenues. These additional amortizations were determined using a model
 4 set out in the Regulatory Plan.

5 The additional amortizations were an addition to the cost of service expenses, and caused
 6 the rate increases resulting from each of the affected rate cases to be greater than the amount of
 7 the increase determined necessary from a traditional cost of service calculation.

8 The additional amortizations resulting from the last three KCPL rate cases were
 9 cumulatively reflected in the revenue requirement calculation for KCPL. The rate cases and
 10 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

12
 13 KCPL's current annual cumulative additional amortizations total \$42.4 million in the last
 14 KCPL rate case on a Missouri-only basis. In this case, a portion of this additional amortization
 15 amount is on the test year ending September 30, 2011 books and must be removed from the cost
 16 of service calculation.

17 The additional amortization levels approved in prior cases have been removed for the
 18 case. Staff adjusted the revenue requirement calculation to remove the test year levels of
 19 \$24.7 million to reflect the end of the additional amortizations in the case to coincide with
 20 the completion of KCPL's Comprehensive Energy Plan in 2010 and resulting from Case No.
 21 EO-2005-0329—the Regulatory Plan. The following Income Statement adjustments were made
 22 to remove the test year levels for the additional amortizations:

<u>EMS Adjustment number</u>	<u>Case Number</u>	<u>Dollar Amount</u>
Adjustment E-249.1	ER-2009-0089	\$5,833,333
Adjustment E-250.1	ER-2007-0291	\$6,255,566
Adjustment E-251.1	ER-2006-0314	<u>\$12,646,119</u>
Total		\$24,735,018

1 No additional amortizations are necessary since the Regulatory Plan the Commission
2 approved in 2005 is completed with respect to the plant additions.

3 The accumulated additional amortizations amounts from the 2006, 2007 and 2009 rate
4 cases are included in Staff's cost of service determination for KCPL as an offset (reduction) to
5 plant in service through the accumulated depreciation reserve. These amounts are reflected in
6 Schedule 6—Depreciation Reserve.

7 In the last KCPL rate case (Case No. ER-2010-0355), several parties, including
8 the Company and Staff, agreed to the on-going treatment for the additional amortizations in
9 future rate cases. The Commission approved a Non Unanimous Stipulation and Agreement
10 Regarding Depreciation and Accumulated Additional Amortizations that authorized the transfer
11 of \$146.7 million of accumulated additional amortizations to Accumulated Depreciation
12 Reserve- Account 399 through May 3, 2011 – the date rates changed in Case No. ER-2010-0355.
13 Since each state (Kansas and Missouri) had separate regulatory plans and collected the additional
14 amortizations from each states' customers separately, all the additional amortizations are
15 identified on a Missouri jurisdictional basis. The amounts of the three additional amortizations
16 from the three rate previous cases as of May 3, 2011, based on the Stipulation are:
17

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

18 KCPL's Accumulated Depreciation Reserve Account 399—page 6, paragraph 7 of 2011 Stipulation

19 Aside from the additional amortizations from KCPL's Regulatory Plan, KCPL also had
20 an additional amortization from a Stipulation and Agreement the Commission approved on

1 July 3, 1996 in Case No. EO-94-199. The Stipulation the Commission approved included a
2 \$3.5 million additional annual amortization. This additional amortization continued resulting in
3 a total accumulation of \$36,674,731 booked in KCPL's Accumulated Depreciation Reserve--
4 Account 399 when it ended on December 31, 2006.

5 The totals of all these accumulated additional amortizations from the Regulatory Plan--
6 Case No. EO-2005-0329 and from Case No. EO-94-199 as of May 3, 2011 are shown as
7 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

8
9 KCPL's Accumulated Depreciation Reserve Account 399—page 6, paragraph 7 of 2011 Stipulation

10 The total additional amortizations of \$183.4 million are treated in a consistent manner
11 with the Stipulation approved in Case No. ER-2010-0355. The accumulated additional
12 amortizations are specifically identified in the plant accounting record system for depreciation
13 reserve. The additional amortizations were distributed to Iatan 2 Uniform System of Accounts--
14 account numbers 311, 312, 314, 315 and 316 --as specified in the Stipulation in the last KCPL
15 rate case.

16 Transferring the Missouri jurisdictional additional amortization amounts to Iatan 2
17 depreciation reserve reduces KCPL's rate base for amounts collected from its customers during
18 the time of the Regulatory Plan. The Stipulation ensured that the additional amortizations
19 collected by Missouri customers are used to the benefit of customer rates through the reduction
20 of rate base.

21 *Staff Expert/Witness: Cary G. Featherstone*

1 **XII. Current and Deferred Income Tax**

2 **A. Income Tax Expense**

3 Both the Staff and KCPL are generally consistent in the dollar amount of the components
4 and the methodology used to calculate KCPL's income tax expense for ratemaking purposes in
5 this case. However, the Staff and KCPL differ in two general areas.

6 First, Staff has included in its calculation of KCPL's current income tax expense a tax
7 deduction that KCPL reflected on its consolidated 2010 federal and state income tax returns
8 related to its Employee Stock Option Plan ("ESOP"). Second, Staff has reflected as an offset to
9 KCPL's income tax expense the full amount of Advanced Coal Investment Tax Credit (ITC) that
10 KCPL would be allowed to take as a tax credit on its stand alone federal and state income tax
11 returns.

12 KCPL's 401(k) Savings Plan is a defined contribution plan covering all full-time and
13 part-time KCPL employees. KCPL added an ESOP component to its 401(k) Savings Plan on
14 January 1, 2002. The ESOP component consists of the portion of the plan that is invested in
15 Great Plains common stock. The ESOP provides KCPL employees the option of receiving a
16 direct cash distribution of any dividends paid on such stock held in participant elective
17 contribution accounts and, if they are 100% vested as of the dividend record date, their Company
18 match accounts. Dividends paid on Great Plains stock are automatically reinvested, unless the
19 employee elected a cash distribution.

20 KCPL's tax deduction related to the payment of dividends through KCPL's ESOP
21 should be reflected in KCPL's cost of service because it is caused by and directly related to
22 KCPL employees who participate in KCPL's ESOP, which is a part of KCPL's 401(k) Savings
23 Plan. The cost of KCPL's 401(k) Savings Plan is fully reflected in rates and being charged to
24 KCPL's customers and, therefore, is directly related to KCPL's provision of utility service to its
25 retail customers.

26 KCPL has not reflected the full amount of the ITC amortization it would be able to reflect
27 as a reduction to income tax expense on a stand-alone KCPL federal and state income tax returns
28 because its parent and affiliate companies, have not had, and are not expected to have sufficient
29 taxable income on a consolidated basis to be able to reflect this tax credit on their consolidated
30 federal and state income tax returns for some time.

1 Many states, including Missouri, use the traditional “stand-alone” method for calculating
2 the amount of income taxes to be incorporated into a regulated utility company’s rates. This
3 method calculates income tax expense based on the regulated revenues and expenses of the
4 utility itself without regard to the utility’s unregulated activities or the operations of its parent
5 and other affiliated companies. The “stand-alone” approach to the calculation of income tax
6 expense is used so that the income taxes included in a utility’s cost of service are based on the
7 cost of the utility providing the regulated utility service. In lieu of the stand-alone method, some
8 states have adopted a ratemaking methodology for income taxes that is often referred to as a
9 “consolidated tax savings adjustment”. There are some arguments in favor of such a
10 methodology, but to my knowledge, the Missouri Commission has only employed the “stand-
11 alone” method in determining income tax expense for Missouri jurisdictional utilities.

12 While it used the traditional “stand-alone” method and reflected the full amount of
13 investment tax credit amortization that is allowed by and required by the Internal Revenue
14 Code’s income tax normalization rules in determining KCPL’s income tax expense, Staff is open
15 to discussions with KCPL and others about calculating KCPL’s income tax expense on a
16 consolidated basis, so long as KCPL is willing to allocate some of its non-regulated tax benefits
17 to KCPL’s Missouri retail customers.

18 Given the significant amount of bonus depreciation and other deductions currently being
19 allowed by the IRS, there is a potential for Staff’s income tax expense proposal to change
20 significantly. Staff recognizes that due to the increased bonus depreciation and other liberalized
21 allowed tax deductions, KCPL may not be able to recognize the full amount of all tax deductions
22 and tax credits that it otherwise would be able to take advantage of on a true utility stand-alone
23 basis. At this point in time Staff is unable to predict the dollar amount of any true-up changes to
24 the level of income tax expense that it is including in its determination of KCPL’s revenue
25 requirement in this direct filing.

26 *Staff Expert/Witness: Charles R. Hyneman*

27 **B. Kansas City Earnings Tax**

28 In the city of Kansas City, Missouri (KCMO), businesses and self-employed individuals
29 pay an earnings tax on net business profits attributable to their activities in KCMO. Net profits
30 earned in KCMO are calculated using a three factor formula based on sales, payroll and property

1 totals within and outside the KCMO city limits. The Kansas City earnings tax is based on federal
2 taxable income multiplied by the Kansas City apportionment factor multiplied by the tax rate
3 of 1%. KCPL appropriately records its Kansas City earnings tax in account 708.110, a Taxes
4 Other Than Income account, as the Kansas City Earnings tax is not an income tax.

5 In Data Request No. 400, Staff asked KCPL for the accrual amounts for KCMO earning
6 taxes expensed on its books in calendar year 2011 and the amounts accrued in 2012 through the
7 month of May. KCPL responded that there was no amount accrued on its books for Kansas City
8 earnings tax in 2011 or 2012.

9 For the calendar years 2009 and 2010, KCPL made actual earnings tax payments of
10 \$74,443 and \$216,458, respectively, to the city of Kansas City. KCPL's 2011 earnings tax
11 liability to Kansas City has not yet been determined, but this information should be available in
12 the Staff's true-up audit in this case. Based on discussions with KCPL, the Staff believes that
13 KCPL may not have a positive taxable income in 2011, primarily due to bonus depreciation
14 deductions currently being allowed by the IRS. However, if KCPL determines it has a net
15 Kansas City earnings tax liability (required cash payment) for 2011 when it completes its 2011
16 income tax returns, the Staff will consider this information in its true-up revenue requirement
17 recommendation.

18 Because the Kansas City earnings taxes are required as a right to conduct business in the
19 city of Kansas City, Staff recommends that a percentage of KCPL's earnings taxes should be
20 allocated to KCPL's Kansas customers and GMO customers who benefit from the corporate
21 functions that are performed in KCPL's downtown Kansas City headquarters building. In
22 KCPL's most recently completed rate case, Case No. ER-2010-0355, Staff recommended that
23 25 percent of KCPL's Kansas City earnings taxes be allocated to Kansas and GMO and also
24 recommended that KCPL perform a study to determine a more precise allocation of this cost. If
25 KCPL determines that it does have a Kansas City earnings tax liability for 2011, then the Staff
26 recommends that 25 percent of any such tax be allocated to Kansas and GMO, unless KCPL can
27 provide a more reasonable allocation basis. KCPL will not know definitively if it has a earnings
28 tax liability to Kansas City until it completes its 2011 income tax return, Form 1120.

29 Since KCPL files its income tax forms on a consolidated basis with its parent company,
30 Great Plains Energy (GPE), GPE's Form 1120 was required to be filed with the IRS on
31 March 15, 2012. KCPL also calculates and files a KCPL-only stand alone Form 1120 with the

1 IRS. However, KCPL regularly requests a six-month extension, which makes the final due date
2 to file its 2011 federal income tax return September 17, 2012. All of the information included on
3 this tax return should be available for the Staff's true-up audit in this case.

4 KCPL's customers should not pay in rates any Kansas City earnings taxes that KCPL
5 does not pay to the city of Kansas City. Because KCPL has not recorded any actual Kansas City
6 earnings taxes in the test year or test year update period, the Staff is not including any Kansas
7 City earnings taxes in its direct cost of service revenue requirement recommendation. The per
8 book amount for Kansas City earnings taxes in the Staff's Accounting Schedules is listed at zero
9 dollars and the Staff is proposing no adjustment to this amount.

10 *Staff Expert/Witness: Chuck R. Hyneman*

11 **C. Accumulated Deferred Income Taxes**

12 KCPL's deferred tax reserve represents, in effect, a prepayment of income taxes by
13 KCPL's customers to KCPL before KCPL pays the federal and state taxing authorities. As an
14 example, because KCPL is allowed to deduct depreciation expense on an accelerated basis for
15 income tax purposes, the income tax depreciation expense deduction KCPL uses for paying
16 income taxes is currently considerably higher than depreciation expense used for ratemaking
17 purposes. This results in what is referred to as a "book-tax timing difference," and creates a
18 deferral of income taxes to the future.

19 KCPL's deferred tax reserve includes deferred tax assets (debit balances) and deferred
20 tax liabilities (credit balances). The net credit balance in KCPL's deferred tax reserve represents
21 a source of cost-free funds for KCPL to use for its utility operations. Therefore, Staff has
22 reduced KCPL's rate base by this deferred tax reserve balance to avoid having customers pay a
23 return on funds that are cost-free to the Company.

24 Both KCPL and Staff are in agreement that the deferred tax impact of the individual
25 events and transactions that are included in and/or related to KCPL's cost of service in the
26 provision of electric utility service should be included in KCPL's accumulated deferred tax
27 reserve and included in its rate base. Staff agrees with many of the individual events and
28 transactions that KCPL included and excluded from its proposed level of accumulated deferred
29 income taxes.

1 During its audit, the Staff identified, and KCPL agreed, that some of the items that KCPL
2 included in its accumulated deferred tax reserve should not be included in KCPL's rate base,
3 items such as the deferred taxes related to the accrual of stock compensation, deferred directors'
4 equity compensation, strategic initiatives, FIN 48 adjustments, and gas hedging related to mark-
5 to-market accounting treatment. Staff reflected these agreed to changes in its level of KCPL
6 accumulated deferred income taxes.

7 In addition, the Staff did not agree with some of KCPL's classifications. The items that
8 are included in Staff's accumulated deferred income taxes balance in KCPL's rate base that
9 KCPL excluded are the timing differences related to loss on required debt and interest on
10 decommissioning and decontamination. Staff included these items as they are related to KCPL's
11 cost of service.

12 The items that Staff excluded (which KCPL included) in the accumulated deferred
13 income tax reserve are Deferred Compensation-non-current, which is related to KCPL's long-
14 term executive incentive plan (which Staff has excluded from cost of service) and 20 percent of
15 KCPL's current officers' deferred compensation, which Staff also recommends should not be
16 included in KCPL's cost of service. Staff's adjustments to KCPL's accumulated deferred
17 income taxes related to incentive compensation are consistent with Staff's revenue requirement
18 treatment of KCPL's total incentive compensation program costs.

19 The bulk of the accumulated deferred tax reserve is made of book-tax timing differences
20 related to depreciation. Staff and KCPL used the same level of accumulated deferred income
21 taxes related to depreciation; however there are differences between Staff and KCPL on the
22 amount included in KCPL's revenue requirement due to the use of different jurisdictional
23 allocation factors. The biggest part of this difference results from the fact that Staff used a total
24 plant allocation factor for non-plant specific depreciation timing differences, while KCPL used a
25 different demand allocation factor.

26 As part of its true-up audit, the Staff will re-examine accumulated deferred income tax
27 balances to make sure all items included in those balances are consistent with the other
28 components of KCPL's cost of service and revenue requirement, and that they reflect the current
29 balances at the true-up cutoff date of August 31, 2012.

30 *Staff Expert/Witness: Charles R. Hyneman*

1 **XIII. Qualifying Advanced Coal Project Credit for Iatan Unit 2 Facility**

2 **Summary and Conclusions**

3 Great Plains Energy, KCPL, and GMO – and Aquila, Inc. (Aquila) prior to the
4 acquisition of Aquila (now GMO) by Great Plains Energy– engaged in improper conduct and
5 imprudent decision-making with regard to the Qualifying Advanced Coal Project Credit for the
6 Iatan 2 Generating Unit (“Iatan 2”).

7 Because of this improper conduct and imprudent decision-making, Staff recommends the
8 Commission order Great Plains Energy, KCPL and GMO to request a reallocation between
9 KCPL and GMO of the Iatan 2 Qualifying Advanced Coal Project Credits from the Internal
10 Revenue Service (“IRS”), at shareholder expense. If the IRS does not reallocate these Iatan 2
11 coal credits to GMO based on its ownership share of the power plant, then KCPL should pay the
12 monetary equivalent to GMO of the value of the coal credits that should be allocated to GMO.

13 In the alternative, the Commission could disallow a portion of the Great Plains Energy,
14 KCPL and GMO officers’ salaries and benefits allocated to GMO. Or, as another alternative,
15 Staff recommends the Commission consider the imprudence of Great Plains Energy, KCPL and
16 GMO regarding the qualifying advanced coal project credit when it determines what return on
17 equity would be reasonable for both KCPL and GMO in these rate cases.

18 **A. Iatan 2 Qualifying Advanced Coal Project Credit**

19 **Introduction/Recommendations**

20 Staff recommends that the Commission order the reallocation of the Iatan 2 Qualifying
21 Advanced Coal Project Credit between KCPL and GMO based on the respective ownership
22 share of each company. Staff further recommends the Commission order Great Plains Energy
23 (as the parent of both KCPL and GMO), KCPL, and GMO to initiate a formal application
24 process with the IRS for the reallocation of Coal Credits to include GMO’s 18% ownership
25 share. Because Iatan 2 is allocated between MPS and L&P, it is also necessary to allocate
26 an amount for the advanced coal credits to both of these entities. Staff recommends GMO be
27 allocated the advanced coal credits based on the percentage allocation of Iatan 2 costs between
28 MPS and L&P. Further, Staff recommends the Commission order Staff to actively participate in
29 the reallocation application process of Great Plains Energy, KCPL and GMO with the IRS to

1 monitor the request to reallocate the advanced coal credits to ensure GMO is properly
2 represented during the process.

3 If the IRS does not allocate a share of the Qualifying Advanced Coal Project Credit to
4 GMO, then the Commission should order KCPL to provide monetary equivalents to GMO up to
5 the level of GMO's rightful share of coal credits.

6 In the alternative, Staff recommends the Commission disallow the allocation of Great
7 Plains Energy, KCPL, and GMO officers' salaries and benefits to GMO-MPS and GMO-L&P
8 because the Great Plains Energy entities – and Aquila prior to the acquisition of Aquila
9 (now GMO) by Great Plains Energy – acted imprudently on at least six separate occasions in the
10 decisions to not allow GMO to apply for the qualifying advanced coal project Credit or to
11 participate in the Arbitration process or the re-allocation process, and ultimately decided to
12 affirmatively waive GMO's right to request an allocation of the coal credits from the IRS when
13 The Empire District Electric Company ("Empire") requested and received permission to receive
14 a share of these credits. The instances when Great Plains entities and Aquila had the opportunity
15 to seek to provide GMO its claim to its rightful share of the Iatan 2 coal credits are:

- 16 1. When Aquila learned of KCPL's plan to apply for the Iatan 2
17 Qualifying Advanced Coal Project Credit in 2007, prior to the July 14,
18 2008 acquisition of Aquila by Great Plains Energy, Aquila should have
19 exercised its claim to these tax benefits by applying to the Department
20 of Energy and the Internal Revenue Service.
- 21 2. When Great Plains Energy and KCPL learned of the dispute with
22 Empire in the fall of 2008, shortly after the Aquila acquisition, and
23 Empire made its claim to the Iatan 2 qualifying advanced coal Project
24 credit, Great Plains Energy and KCPL should have included GMO in
25 the resolution of this dispute.
- 26 3. When Great Plains Energy and KCPL learned that the IRS considered
27 the Coal Credits for Iatan 2 as being awarded on an Iatan 2 Project
28 basis, rather than on an individual owner basis, Great Plains Energy and
29 KCPL should have included GMO (and Empire) in the allocation of
30 Tax Credits.
- 31 4. Great Plains Energy and KCPL should have included GMO in the
32 Arbitration process with Empire in the fall of 2009.
- 33 5. After the Arbitration decision on December 30, 2009, Great Plains
34 Energy and KCPL should have included GMO in the request made to
35 the IRS for reallocation of the Iatan 2 Coal Credits.

1 "2010 rate case"). The Commission ordered KCPL to request from the IRS a re-allocation of the
2 tax credit for GMO (see March 16, 2011 Order in Case No. ER-2010-0355).

3 The Commission's March 16, 2011 Order stated in a unanimous decision:

4 No later than April 5, 2011, GMO and KCPL shall apply, at the
5 shareholders' expense, to the Internal Revenue Service for an amendment
6 of the Memorandum of Understanding that would allow KCP&L Greater
7 Missouri Operations Company to obtain a share of the Section 48A tax
8 credits for Iatan 2, Section 48A tax credits equal to \$26,500,000.

9 The \$26,500,000 amount was corrected in the Commission's March 30, 2011 Order to
10 \$26,562,000. The original amount was identified in testimony, upon which the Commission
11 relied, as a rounded amount.

12 KCPL and GMO sent a letter to the IRS on April 5, 2011, the date the Commission had
13 required KCPL to provide this letter to the IRS, requesting the allocation of the Qualifying
14 Advanced Coal Credits to GMO (see Appendix 3, Highly Confidential Schedule CGF 1) [Data
15 Request No. 0669, ER-2010-0355].

16 The IRS rejected the request to allocate any of the Qualifying Advanced Coal
17 Project Credit to GMO on August 24, 2011 (see Appendix 3, Highly Confidential Schedule
18 CGF 2). ** _____
19 _____
20 _____
21 _____
22 _____
23 _____

24 KCPL, a member of the IRS, and Staff held a conference call on September 21, 2011 to
25 discuss why the IRS denied KCPL and GMO's request for allocation of the qualifying advanced
26 coal project credit to GMO. Staff compiled notes from this meeting which are attached as
27 Appendix 3, Highly Confidential Schedule CGF 3.

28 During the discussion with the IRS representative, Staff ask ** _____
29 _____
30 _____
31 _____
32 _____

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35

**

At the time of filing this direct testimony, Great Plains Energy has not made any further application to the IRS requesting an allocation be made for GMO. As part of Staff's recommendation it is requesting the Commission order Great Plains Energy along with KCPL and GMO to reapply with IRS requesting a further amendment to MOU to include an allocation of these coal credits to GMO.

The Commission reached a unanimous decision regarding the Tax Credits in its Order in Case No. ER-2010-0355 dated March 16, 2011:

Although the Commission is not bound by the decision of the arbitration panel, the Commission accepts the findings of the arbitration panel. Even though each party under the Iatan 2 Agreement was responsible for paying and filing its own taxes, **as the operator of Iatan KCPL owed a special duty to its co-owners. KCPL should have advised GMO and the other co-owners of its intent to request the availability of Section 48A credits and of its lobbying efforts to amend the law so that Iatan 2 qualified for the tax credits.** The tax credits in the amount of \$125 million were certainly significant to the operation and construction of the facility, and were obviously part of KCPL's operations strategy.

In addition, once arbitration proceedings had begun, GMO should have been involved, in order to protect its own interest. It is clear that even though KCPL may not have realized it at the time, KCPL could not adequately represent the interest of GMO in the arbitration proceedings.

Since Great Plains Energy and its affiliates file joint tax returns it does not matter to the shareholders whether KCPL or GMO has the tax credits. But, which company has the tax credits can make a difference to the ratepayers because it may affect the cost of service. If the advanced coal tax credits are imputed to GMO it will lower the cost of GMO to serve its customers and, therefore, lower GMO rates.
[emphasis added]

The Commission clarified its March 16, 2011 Order on March 30, 2011 wherein it changed the above wording in its Findings of Fact 24 in the March 16 Order from "imputed to GMO" to "allocated to GMO."



1 The Commission recognized in its March 16 Order that GMO and the other co-owners
2 should have been informed of KCPL's intent of applying for these Coal Credits.

3 **

4

5

6 **

7 When asked if KCPL informed the other owners about the Iatan 2 coal credits,
8 KCPL informed Staff that the other Iatan 2 owners were viewed as "competitors" for the finite
9 amount of monies available for these credits. KCPL did not inform any of the other owners
10 except GMO (Aquila at the time) about KCPL's application with the DOE and IRS regarding the
11 Iatan 2 coal credits. KCPL informed GMO about the coal credits because of the pending
12 acquisition agreement.

13 Analysis

14 These tax benefits relating to the construction and operation of the newly constructed
15 Iatan 2 coal-fired generating unit became available when Congress enacted the Energy Policy
16 Act of 2005 (the "2005 Energy Act"), signed into law on August 8, 2005. The 2005 Energy Act
17 provided the opportunity for owners of newly constructed power plants burning clean coal and
18 meeting certain emission standards to apply with the Department of Energy and the Internal
19 Revenue Service for qualifying coal credits. These coal credits were called Section 48A
20 Qualifying Advanced Coal Project Credit (herein referred to as the "Iatan 2 Credits,"
21 "Tax Credits," "Coal Credits" or "Section 48A Credits").

22 In 2006 and 2007, KCPL applied with the IRS and DOE for coal credits relating to the
23 850 megawatt Iatan 2 coal-fired generating unit. KCPL first applied for coal credits in 2006
24 without informing any of the other Iatan 2 owners, but was initially denied because the plant did
25 not qualify. KCPL lobbied Congress for a change in law so Iatan 2 would qualify for credits and
26 the law was subsequently changed. KCPL then re-applied for the coal credits in 2007 and the
27 Iatan 2 project was successful with this re-application. At the time of its re-application, KCPL
28 informed Aquila that it was applying for the Iatan 2 coal credits because of the pending
29 acquisition of Aquila (now GMO) by KCPL's parent, Great Plains Energy. Aquila did not
30 pursue the coal credits when it learned of the existence of such credits.

1 After the July 14, 2008 acquisition of Aquila by Great Plains Energy, GMO applied
2 for the coal credits in an application dated October 30, 2008—this GMO application for the
3 Iatan 2 coal credits is attached as Appendix 3, Highly Confidential Schedule CGF 4. ** __
4
5

6 _____ **

7 On April 28, 2008 KCPL was notified by the IRS that KCPL's application had been
8 successful in qualifying for Iatan 2 Advanced Coal Project Credits (see Appendix 3, Highly
9 Confidential Schedule CGF 5). The IRS indicated the Iatan 2 project was allocated
10 \$125 million. The IRS stated that "based on the information supplied in your [KCPL]
11 application, we [the IRS] have accepted the Project's application and have allocated
12 \$125,000,000 of Section 48A credit to the Project." It is clear from this communication that the
13 qualifying advanced coal project credit was for Iatan 2 Project, not for KCPL, or at least it
14 should have been clear. KCPL entered into its original Memorandum of Understanding with the
15 IRS dated August 26, 2008 (see Appendix 3, Highly Confidential Schedule CGF 5) regarding the
16 receipt of the \$125 million amount of the Iatan 2 Project Coal Credits [source: Data Request No.
17 0866—ER-2009-0089]. The August 2008 Memorandum of Understanding with KCPL would
18 later be amended on August 19, 2010 to include allocating a portion of the qualifying advanced
19 coal project credit for Iatan 2 to Empire.

20 The coal credit application was evaluated by DOE and the IRS based on the size of the
21 generating unit and its meeting certain qualifying environmental emission standards.
22 Additionally, in order to meet the advanced clean coal standards and avoid forfeiture and/or the
23 recapture of credits in the future, Iatan 2 must meet or exceed certain qualifying environmental
24 performance requirements for at least five years, once the plant went into service.

25 Iatan 2 is co-owned by KCPL, GMO, Empire, Missouri Joint Municipal Electric Utility
26 Commission (MJMEUC) and Kansas Electric Power Cooperative, Inc. (KEPCO). In KCPL's
27 application to the Department of Energy dated October 30, 2007 (see Appendix 3, Highly
28 Confidential Schedule CGF 6), KCPL supplied the following information relating to the
29 ownership of Iatan 2:

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20

** _____

_____ **

[source: page 12 KCPL application October 30, 2007- Department of Energy Section 48A Certification Application for Advanced Coal Project Credits—Data Request 135, Case No. ER-2010-0355]

21
22
23

Each of the ownership shares represented an amount of megawatt (MW) capacity and, ultimately, its related energy output based on this megawatt capacity, as follows:

Utility	Ownership Share	Megawatt Capacity
KCPL	54.71%	465 MW
GMO (former Aquila)	18%	153 MW
Empire District Electric	12%	102 MW
Missouri Joint Municipal Electric Utility Commission	11.76%	100 MW
Kansas Electric Power Cooperative, Inc.	3.53%	30 MW
Total	100%	850 MW

24

1 On October 9, 2008, KCPL was notified by Empire of Empire's view that a portion of the
2 qualifying advanced coal project credit previously awarded to KCPL should be allocated to
3 Empire. The Notice of Controversy (see Appendix 3, Highly Confidential Schedule CGF 7-4)
4 served as written notice to KCPL of the dispute pursuant to Section 12.1 of the IATAN UNIT 2
5 AND COMMON FACILITIES OWNERSHIP AGREEMENT.

6 On November 21, 2008, KCPL's president, William H. Downey, responded to Empire
7 that KCPL would not agree to allocate Empire a share of the Qualifying Advanced Coal Project
8 Credits- the "Tax Credits" (see Appendix 3, Highly Confidential Schedule CGF 7-9).
9 Mr. Downey stated:

10 ** _____
11 _____
12 _____
13 _____
14 _____
15 _____
16 _____
17 _____
18 _____
19 _____
20 _____
21 _____
22 _____
23 _____
24 _____ **

25 On July 10, 2009, KCPL was served a Notice to Arbitrate (see Appendix 3, Highly
26 Confidential Schedule CGF 7-12) by Empire and the remaining co-owners of Iatan 2 (other than
27 GMO, which was now owned by Great Plains), KEPCO and MJMEUC. The co-owners
28 contended that they were entitled to receive proportionate shares (or the monetary equivalent) of
29 the \$125 million advanced coal project credits for Iatan Unit 2.

30 In November 2009, this matter was heard by a three person arbitration panel. On
31 December 30, 2009, the arbitration panel, convened pursuant to Article XII of the Iatan Unit 2
32 And Common Facilities Ownership Agreement, issued a unanimous decision ordering KCPL and
33 Empire to jointly seek a reallocation of the tax credits giving Empire its representative share of

1 the total tax credits based on Empire's 12% ownership of Iatan 2, and worth approximately
2 \$17.7 million in tax credits to Empire (the Final Arbitration Award is herein referred to as the
3 "Arbitration Order"— see Appendix 3, Highly Confidential Schedule CGF 8). The December 30
4 Arbitration Order denied KEPCO's and MJMEUC's claims to the Tax Credits. The Arbitration
5 Order further specified that if the IRS denied KCPL and Empire's reallocation request, or if
6 Empire was allocated less than its proportionate share of the tax credits, KCPL would be
7 responsible for paying Empire the full value of its representative percentage of the tax credits
8 (less the amount of tax credits, if any, Empire ultimately received) in cash.

9 The following are excerpts from the Arbitration Order:

10 KCPL planned to apply for the Section 48A tax credits with respect to
11 Iatan 2 even before it negotiated the Ownership Agreement with the other
12 Owners; yet it told none of them. In August, 2006, KCPL filed
13 applications with the IRS and the US Department of Energy ("DOE")
14 requesting that the Iatan 2 project be certified by the DOE as meeting the
15 requirements set forth in Section 48A. The application was not successful.
16 KCPL did not tell any of the other Owners that it had made this filing, nor
17 did it discuss with them whether they should or could have filed an
18 application at the same time or whether KCPL and some of the other
19 Owners could have filed a joint application. These actions of KCPL
20 constituted willful misconduct.

21 Once KCPL's initial application for the Section 48A tax credits was
22 denied, KCPL lobbied for an amendment to Section 48A to allow Iatan 2
23 to qualify for such credits. KCPL did not tell any of the other Owners that
24 it was doing so nor did KCPL tell any of the other Owners that it had hired
25 a contractor and, in turn, a subcontractor to assist in determining whether
26 Iatan 2 qualified under the amended statute. As Operator, KCPL had a
27 duty to inform the other Owners of its efforts to determine whether Iatan 2
28 qualified for the Section 48A credits and what impact that would have on
29 the construction of Iatan 2. Again, these actions of KCPL constituted
30 willful misconduct.

31 * * * *

32 Despite not having told any of the other Owners of its efforts to
33 investigate whether Iatan 2 would qualify for the Section 48A credits, and
34 despite not having given the other Owners the opportunity to file a joint
35 application or apply on their own behalf, KCPL nonetheless charged the
36 other Owners for the costs of (a) evaluating whether Section 48A credits
37 would be available and (b) applying for the Section 48A credits. In fact,
38 KCPL charged the other Owners for the cost of investigating whether

1 Iatan 2 would qualify for the credits, but it never informed the other
2 Owners of the investigation, the results thereof or its own application for
3 the credits.

4 During the period in which it was investigating whether Iatan 2 would
5 qualify for the Section 48A credits and thereafter in 2006 and 2007 when
6 it was applying for the credits, KCPL did not inform any of the other
7 Owners of its investigation, nor did it have any discussions with Empire,
8 KEPCO or MJMEUC regarding the Section 48A credits or the
9 applications with the IRS and DOE. KCPL did, however, discuss the
10 Section 48A credits with co-Owner GMO, which was subsequently
11 acquired by KCPL's parent company.

12 The actions of KCPL constituted "willful misconduct" in that KCPL acted
13 willfully and in an opportunistic manner to garner all of the benefits of the
14 Section 48A credits for itself while billing the other Owners for their share
15 of certain costs incurred in qualifying the project for such credits and
16 thereafter applying for the credits (at the same time it was sharing its plan
17 with co-Owner GMO, with whom it would soon be affiliated). KCPL's
18 actions also clearly constituted a breach of the implied duty of good faith
19 and fair dealing imposed by Missouri contract law.

20 KCPL has not made any payments to the other Owners with respect to the
21 tax benefits, if any, it has received as a result of obtaining the Section 48A
22 credits.

23 Based on the foregoing, it is the unanimous opinion of the Arbitration
24 Panel that:

25 (1) KCPL breached Sections 4.1, 5.3(a), 6.5(d) and 21.1 of the Ownership
26 Agreement, and also the implied duty of good faith and fair dealing, by
27 evaluating the project's eligibility for, and applying for, Section 48A
28 credits without bringing these matters to the attention of the other Owners;

29 (2) Empire sustained damages as result of KCPL's breach of Sections 4.1,
30 5.3(a), 6.5(d) and 21.1 of the Ownership Agreement (and also the implied
31 duty of good faith and fair dealing), due to the fact that such breach
32 prevented Empire from successfully applying for its fair share of Section
33 48A credits allocated to the project.

34 * * * *

35 Accordingly, IT IS HEREBY ORDERED:

36 (1) KCPL and Empire shall apply to the IRS for an amendment of the
37 MOU that would allow Empire to obtain a share of the Section 48A tax
38 credits equal to \$17,712,500. If the IRS approves such an amendment to
39 the MOU, then no further relief is required for Empire.

1 (2) If the application to amend the MOU is denied, or if Empire is
2 allocated less than \$17,712,500 in Section 48A tax credits under the
3 amended MOU, then KCPL shall immediately pay the following amount
4 to Empire: \$17,712,500, less the amount of Section 48A tax credits, if any,
5 allocated to Empire under the amended MOU.

6 (3) If it has not already done so, KCPL shall pay to KEPCO and
7 MJMEUC, immediately, any amounts previously paid by KEPCO and
8 MJMEUC with respect to the costs incurred by KCPL in (a) determining
9 whether the Iatan 2 project qualified for the Section 48A credits,
10 (b) working to amend Section 48A in order to ensure that the Iatan 2
11 facility qualified for the Section 48A credits and (c) applying for the
12 Section 48A credits. Empire shall not be entitled to receive any such
13 payment from KCPL.

14 (4) Claimants' (and, if applicable, KCPL's) requests for attorneys' or
15 experts' fees, costs, carrying charges and interest are hereby denied.

16 (Emphasis added; pages 3-5 of the Arbitration Order).

17 Selected pages that identifies Sections 4.1, 5.3(a), 6.5(d) and 21.1 from the May 19, 2006
18 Iatan Unit 2 and Common Facilities Ownership Agreement are attached as Appendix 3,
19 Schedule CGF 9.

20 All of the Arbitration Panel's statements regarding and characterizations of KCPL's
21 conduct regarding the issue of receipt by Empire of its rightful proportionate share of the coal
22 credits apply with equal force to the other investor-owned co-owner of the Iatan 2 unit, GMO.
23 However, as GMO was owned by Great Plains Energy at the time of the arbitration decision,
24 GMO was not allowed by Great Plains Energy to act in its own and its customers' best interest
25 and seek to obtain its rightful proportionate share of the coal credits.

26 In early 2010, KCPL and Empire requested a reallocation of the Tax Credits from the IRS
27 pursuant to the Arbitration Order. Empire received its share of the Coal Credits through a
28 revised Memorandum of Understanding from the IRS dated August 19, 2010. (see Appendix 3,
29 Highly Confidential Schedule CGF 10-5)

30 The reallocation changed the amount allocated to KCPL as follows:

1

	Original Memorandum of Understating	Revised Memorandum of Understanding
KCPL	\$125,000,000	\$107,287,500
Empire	\$0	\$ 17,712,500
Total	\$125,000,000	\$125,000,000

2

3

4

5

6

If GMO had been included in the reallocation of the \$125 million amount of Coal Credits based on its 18% ownership share, Empire's allocated amount would remain the same but KCPL's share would be further reduced as follows:

	Original Memorandum of Understating	Revised Memorandum of Understanding	Reallocation including GMO
KCPL	\$125,000,000	\$107,287,500	\$80,725,000
Empire	\$0	\$17,712,500	\$17,712,500
GMO	\$0	\$0	\$26,562,500
Total	\$125,000,000	\$125,000,000	\$125,000,000

7

8

9

10

The three member arbitration panel determined that KEPCO and MJMEUC were not eligible to share in any of the Iatan 2 Coal Credits because they both were non-taxpayers. The Arbitration Panel found:

11

12

13

14

15

16

17

18

19

(3) Despite KCPL's breach of Sections 4.1, 5.3(a), 6.5(d) and 21.1 of the Ownership Agreement (and the implied duty of good faith and fair dealing), KEPCO and MJMEUC have no right to claim tax credits under Section 48A. Section 50(b)(3) of the Internal Revenue Code states that no credit shall be determined under Subpart E with respect to any property used by an organization which is exempt from tax, unless such property is used predominately in an unrelated trade or business. Under this provision, KEPCO could not have applied for or obtained tax credits under Section 48A with respect to KEPCO's investment in the project. Further,

1 Section 50(b)(4)(A) states that no credit shall be determined under Subpart
2 E with respect to any property used by a political subdivision of any state.
3 Under this provision, MJMEUC could not have applied for or obtained tax
4 credits under Section 48A with respect to MJMEUC's investment in the
5 project...

6 [Source: Arbitration Award decision- page 4, item (3)]

7 The Arbitration Panel concluded that although "...KCPL engaged in willful and
8 opportunistic misconduct..." respecting its dealings with KEPCO and MJMEUC regarding the
9 Coal Credits, it could not grant the relief requested by these two non-taxpaying owners.

10 After KCPL and Empire requested the IRS to reallocate a portion of the Coal Credits to
11 Empire pursuant to the Arbitration Order, and before they received the revised Memorandum of
12 Understanding from the IRS dated August 19, 2010, ** _____
13 _____
14 _____
15 _____
16 _____

17 _____ **

18 ** _____
19 _____
20 _____
21 _____
22 _____
23 _____
24 _____
25 _____
26 _____
27 _____
28 _____ **

29 Attached to the May 3, 2010 letter to the IRS, an officer of Great Plains Energy, KCPL,
30 and GMO signed Declarations Under Penalties of Perjury on behalf of both Great Plains Energy
31 and GMO. The Declaration Under Penalties of Perjury was signed by Terry Bassham, then
32 Great Plains Energy's Executive Vice President- Finance and Strategic Development and Chief

1 Financial Officer. Mr. Bassham also signed for GMO as the Executive Vice President- Finance
2 and Strategic Development and Chief Financial Officer:

3 ** _____
4 _____
5 _____
6 _____ **

7 Mr. Bassham was appointed by the Great Plains Board of Directors in 2012 as Chief
8 Executive Officer effective June 1, 2012.

9 GMO, having no independent voice, could not object to the waiving of its right to the Tax
10 Credits. This final act in the spring of 2010 was the culmination of all the negative actions and
11 failures to act which face the Commission in its attempt to solve the adverse detriments placed
12 upon GMO and its customers by not receiving GMO's rightful share of the tax benefits derived
13 from the construction and operations of Iatan 2. All costs relating to the environmental
14 equipment which was installed that allowed Iatan 2 to qualify for the clean coal tax credits were
15 paid initially by Aquila and, after the acquisition, by GMO on an 18% ownership basis. Yet,
16 despite several opportunities to correct the misconduct, Great Plains Energy and KCPL engaged
17 in opportunistic behavior that deprived GMO its proportionate share of these tax benefits. The
18 IRS would have been indifferent if GMO had been included in the allocation request at the time
19 when Empire made its request. The Arbitration Panel would also have had no reason to exclude
20 GMO from an allocated share of the tax benefits based on its 18% ownership interest. Indeed,
21 fairness would have prevailed and GMO, like Empire, would have been allocated 18%, or
22 \$26,562,500 worth of credits, representing its ownership share of the total \$125 million in credits
23 awarded to the Iatan 2 Project.

24 **1. Iatan 2 Costs and Iatan 2 Benefits**

25 During the construction of Iatan 2 and each month of operation throughout its service
26 life, KCPL invoiced and will continue to invoice each owner its proportionate share of costs to
27 build and operate the unit. The owners, including GMO (Aquila pre-acquisition), are required to
28 reimburse KCPL for these costs based on the Iatan 2 Operating Agreement. All costs to
29 construct and operate Iatan 2 are expected to be paid by the co-owners of this generating facility
30 and, conversely, all benefits derived from Iatan 2 are expected to be given to the owners. The
31 owners of this unit all share in the benefit of the low-cost production of electricity based on the

1 proportionate ownership share of each. In the case of the Tax Credits, the tax-paying owners
2 should all share in the proportional ownership of the \$125 million in awarded Tax Credits.
3 Empire received approximately \$17.7 million of the Tax Credits and GMO has yet to receive any
4 of these tax benefits. Staff recommends that GMO should be authorized \$26,562,500 million
5 based on its ownership share of the total \$125 million Tax Credits awarded the Iatan 2 Project.

6 KCPL engaged in "willful misconduct" and was imprudent with respect to not including
7 GMO when KCPL first learned of the dispute with Empire; not including GMO in the 2009
8 Arbitration process; not including GMO in the request for reallocation of the Tax Credits after
9 the Arbitration Panel decided that Empire should have been included in the allocation of the Tax
10 Credits; and in affirmatively waiving or signing-away GMO's right to claim any allocation of
11 Tax Credits from the IRS.

12 **2. Kansas City Power & Light Company's Obligations to KCP&L**
13 **Greater Missouri Operations Company**

14 After the July 14, 2008 acquisition of Aquila's Missouri electric properties by
15 Great Plains, KCPL entered into an agreement with GMO dated October 10, 2008 (herein
16 referred to as the "Joint Operating Agreement") to provide operational services, including tax
17 services, to GMO. All former Aquila employees retained by Great Plains were transferred to
18 KCPL. As such, GMO does not have any employees. Through the Joint Operating Agreement,
19 KCPL is obligated to provide all activities necessary to operate, maintain, plan, direct and
20 oversee GMO (*see* Appendix 3, Schedule 12).

21 The Joint Operating Agreement was signed on behalf of both KCPL and GMO by the
22 same KCPL officer, William H. Downey, President and Chief Operating Officer of KCPL and
23 President and Chief Operating Officer of Aquila, Inc., doing business as KCP&L Greater
24 Missouri Operations. William G. Riggins, General Counsel and Chief Legal Officer for KCPL
25 and Aquila, Inc., doing business as KCP&L Greater Missouri Operations, also signed the Joint
26 Operating Agreement representing both KCPL and GMO.

27 Since GMO has no employees, KCPL is identified as GMO's Designated Agent and
28 Operator. Section 1.2 of the Joint Operating Agreement states:

29 Section 1.2 KCP&L Designated Agent and Operator. KCP&L GMO
30 hereby designates KCP&L as its agent and operator of its business and
31 properties. KCP&L shall be responsible for and shall perform, through its
32 employees, agents, and contractors, all such actions and functions

1 (including, without limitation, the entry into contracts for the benefit of or
2 as agent for KCP&L GMO) as may be required or appropriate for the
3 proper design, planning, construction, acquisition, disposition, operation,
4 engineering, maintenance and management of KCP&L GMO's business
5 and properties in accordance with the terms of this Agreement (the
6 "Services"). KCP&L GMO hereby delegates to KCP&L, and KCP&L
7 hereby accepts responsibility and authority for the duties set forth in this
8 Agreement.

9 The Joint Operating Agreement identifies how KCPL is to treat GMO in making
10 operational decisions. Section 1.8 of the Joint Operating Agreement between KCPL and GMO
11 states:

12 Section 1.8 Parity of Services and Internal KCP&L Operations.
13 KCP&L will at all times use its commercially reasonable efforts to
14 provide the Services in scope, quality and schedule equivalent to those it
15 provides to its own internal operations. In providing the Services,
16 **KCP&L will seek to maximize the aggregate synergies to both**
17 **companies, and shall not take any action that would unduly prefer**
18 **either party over the other party. (emphasis added)**

19 In defining Services that KCP&L provides to GMO, Section 1.3 of the Joint Operating
20 Agreement states:

21 Section 1.3 Description of the Services. The Services shall include all
22 services required or appropriate for the design, planning, construction,
23 acquisition, disposition, operation, engineering, maintenance and
24 management of KCP&L GMO's business and properties. The Services
25 exclude wholesale electricity and transmission service transactions
26 between KCP&L and KCP&L GMO, which will be governed by
27 applicable Federal Energy Regulatory Commission ("FERC") tariffs and
28 rules...

29 Appendix A to the Joint Operating Agreement more fully describes the Services KCP&L
30 is required to provide GMO. Appendix A – Description of Services identifies the Services as:

31 General descriptions of the Services to be provided by KCP&L to KCP&L
32 GMO are detailed below. The descriptions are deemed to include services
33 associated with, or related or similar to, the services contained in such
34 descriptions. The descriptions are not intended to be exhaustive, and
35 KCP&L will provide such additional services, whether or not referenced
36 below, that are necessary or appropriate to meet the service needs of
37 KCP&L GMO.

38 Under the category "Income and Transaction Taxes" the Joint Operating Agreement
39 states KCPL is:

1 Responsible for all aspects of maintaining the tax books and records of all
2 Great Plains Energy entities, including KCP&L GMO. Tax services can
3 be categorized in five major functions providing the primary services as
4 follows: prepare, review and file all consolidated and separate federal,
5 state and local income, franchise, sales, use, gross receipts, fuel excise,
6 property and other miscellaneous tax returns and payments; research tax
7 issues and questions, including interpretation of rules and proceedings,
8 develop short and long range planning for all types of taxes and monitor
9 and review new or proposed tax laws, regulations, court decisions and
10 industry positions; provide tax data for budget estimates and rate cases,
11 provide reports of tax activity and projected cash requirements and
12 prepare, review and record tax data for financial reports; supervise and
13 review tax audit activities; respond to vendor-related tax matters
14 associated with tax compliance or tax saving opportunities and process
15 customer tax refunds and adjustments to customer accounts.

16 The Joint Operating Agreement between KCPL and GMO is included as Appendix 3,
17 Schedule CGF 12.

18 In effect, GMO (as the former Aquila entity) lost all ability to make any decisions
19 independently from KCPL, to advocate its own self-interest, and to defend itself from decision-
20 making that was not in its best interest. The Joint Operating Agreement required KCPL to
21 always make decisions regarding the operations of GMO that are in the best interest of GMO in
22 that **“KCP&L will seek to maximize the aggregate synergies to both companies, and shall
23 not take any action that would unduly prefer either party over the other party.”**
24 (Section 1.8 of Joint Operating Agreement)(emphasis added).

25 In the case of the Tax Credits, GMO had no voice to raise its objections that it was
26 excluded from participation in the Arbitration process or to request a reallocation of the Tax
27 Credits from the IRS at the time when Empire made such request. While KCPL could not
28 silence Empire, it had complete control over ensuring GMO did not receive any benefit from the
29 Tax Credits. In this instance, KCPL has not fulfilled its obligation as GMO’s “agent and
30 operator of its business and properties” (Section 1.2 of Joint Operating Agreement).

31 The Great Plains Energy officers are the same as the officers for KCPL and GMO. All
32 officers of KCPL are also officers of GMO. All the Board of Directors of Great Plains Energy
33 are also Board members of KCPL and GMO with the exception of one.

34 No independent voice can be found in the entire organization of Great Plains Energy and
35 its wholly-owned affiliates—KCPL and GMO- that could promote, support and defend any
36 decision by GMO to pursue its rightful share of the Iatan 2 coal credits.

1 **3. Iatan 2 Coal Credits Are an Acquisition Detriment**

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

9 GMO had no voice to request the Coal Credits for its ownership share of Iatan 2 because
10 of the acquisition by Great Plains. Since KCPL is the only Great Plains entity which has
11 employees, KCPL did not allow GMO to participate in the arbitration process and also did not
12 include GMO when it made a request to the IRS for the reallocation to Empire. Absent the
13 acquisition, Aquila (GMO) would have been in position to take part in the arbitration process
14 and, more importantly, it would have requested a share of the Coal Credits when the IRS was
15 requested to reallocate Coal Credits to Empire. Because the acquisition gave Great Plains and
16 KCPL complete control over the operations of GMO, including all decisions regarding the Coal
17 Credits, GMO could not request to participate in the allocation of these credits, much less defend
18 itself against KCPL’s insistence that the Coal Credits belonged solely to KCPL. After the Aquila
19 acquisition, KCPL represented the interests of GMO, or in the case of the Coal Credits, KCPL
20 ensured that GMO could not participate in any respect in seeking an allocation of these credits.
21 The acquisition provided KCPL the opportunity to speak for GMO which, with regard to the
22 Coal Credits, gave KCPL the opportunity to silence GMO. If Aquila had not been acquired by
23 Great Plains, Aquila would have had the same opportunity as Empire to pursue the Coal Credits.
24 Aquila – like Empire – would have been awarded its proportionate share of the Coal Credits had
25 it been allowed to participate in the arbitration process and the request to the IRS to reallocate
26 the \$125 million coal credits among KCPL, Empire and Aquila based on the ownership share of
27 each.

28 In the acquisition application filed in Case No. EM-2007-0374, the applicants
29 indicated that the acquisition of Aquila by Great Plains Energy would not result in a detriment to
30 the public. GMO losing its ability to make independent decision-making regarding the
31 qualifying advance coal credits that would be in GMO and its customers’ best interest is an

1 acquisition detriment. GMO lost its ability to speak for itself and was disadvantaged in doing so.
2 KCPL capitalized on an opportunity to seek the benefits of the coal credits at the expense of
3 GMO. The Commission should not let this happen and ensure the benefits of these coal credits
4 are available to GMO just as those benefits are available to KCPL.

5 *Staff Expert/Witness: Cary G. Featherstone*

6 **XIV. Jurisdictional Allocations**

7 The Missouri Public Service Commission sets cost-of-service based rates for the utility's
8 Missouri retail customers; however, not all the costs a utility incurs are associated with its
9 provision of service to its Missouri retail customers. KCPL has both retail and wholesale
10 customers in both Missouri and Kansas. Wholesale sales, retail sales in Missouri, and retail sales
11 in Kansas are described as sales in three separate "jurisdictions." Some costs to serve a
12 particular jurisdiction may be directly assigned to that jurisdiction; however, other costs may not.
13 Costs that are not directly assigned to a particular jurisdiction are allocated among the various
14 jurisdictions. Costs that correlate with energy-generally costs that vary with energy
15 consumption-are denoted as "energy-related". Costs that correlate with demand-generally costs
16 that do not vary with energy consumption, i.e. "fixed costs"-are denoted as "demand-related".
17 Different allocation factors are developed and utilized for each.

18 Jurisdictional allocation refers to the process by which demand-related and energy-related
19 costs are allocated to the applicable jurisdictions. Fixed costs, such as the capital costs
20 associated with generation and transmission plant, are allocated on the basis of demand.
21 Variable costs, such as fuel, are more appropriate to allocate on the basis of energy consumption.
22 In this Case, Staff calculated jurisdictional allocation factors for demand and energy to allocate
23 KCPL's demand-related (fixed) costs and energy-related (variable) costs between the three
24 applicable jurisdictions: Missouri retail jurisdiction, Kansas retail jurisdiction, and the wholesale
25 jurisdiction. Which particular jurisdictional allocation factor is applied depends upon the nature
26 of the cost being allocated among the associated jurisdictions.

27 *Staff Expert/Witness: Alan J. Bax*

1 **A. Methodology**

2 **1. Demand Allocation Factor**

3 Demand refers to the rate at which electric energy is delivered to a system to match the
4 energy requirements of its customers, generally expressed in kilowatts (kW) or MegaWatts
5 (MW), either at an instant in time or averaged over a designated interval of time. System peak
6 demand is the largest electric requirement occurring within a specified period of time (e.g., hour,
7 day, month, season, and year) on a utility's system. In addition, for planning purposes, an
8 amount of kW or MW in excess of anticipated system peak demand must be included for
9 meeting required contingency reserves. Since generation units and transmission lines are
10 planned, designed, and constructed to meet a utility's anticipated system peak demands plus
11 required reserves, the contribution of each of the three individual jurisdictions coincident to these
12 system peak demands is the appropriate basis on which to allocate the costs of these facilities.

13 Thus, the term coincident peak (CP) refers to the load, generally in kW or MW, in each
14 of the jurisdictions that coincide with KCPL's overall system peak recorded for the time period
15 used in the corresponding analyses.

16 Staff utilized a 4CP method - based on the monthly seasonal coincident peaks of the four
17 summer months in the test period - to determine the demand allocation factors, the same method
18 that the Commission ordered in Case No. ER-2006-0314, and which both KCPL and PSC Staff
19 used in each subsequent KCPL rate case (Case Nos. ER-2007-0291, ER-2009-0089 and ER-
20 2010-0355). The 4CP method is appropriate for a utility such as KCPL that experiences
21 dominant demands in the four summer months (June through September) relative to the demands
22 in the other eight months of a year. A utility that experiences a needle peak in a particular month
23 may utilize the 1 CP method, or a utility that experiences comparatively similar hourly peaks in
24 both winter and summer months might employ the 12 CP method. In analyzing the monthly
25 demands for the twelve month period ending March 2012, the test year utilized by Staff in the
26 current rate case, these demands are consistent with the monthly demands in the test periods
27 associated with these three aforementioned rate cases.

1 Staff determined the demand allocation factor for each jurisdiction using the following
2 process:

- 3 a. Identify KCPL's peak hourly load in each month for the four -
4 month period June 2011 through September 2011 and sum the
5 hourly peak loads.
- 6 b. Sum the particular jurisdiction's corresponding loads for the hours
7 identified in a. above.
- 8 c. Divide b. above by a. above.

9 The result is the allocation factor for each jurisdiction:

10	• Missouri Retail Jurisdiction:	0.5253
11	• Kansas Retail Jurisdiction:	0.4726
12	• Wholesale Jurisdiction:	<u>0.0021</u>
13	• Total:	1.0000

14 *Staff Expert/Witness: Alan J. Bax*

15 **B. Energy Allocation Factor**

16 Variable expenses, such as fuel, are allocated to the jurisdictions based on energy
17 consumption. The energy allocation factor for each jurisdiction is the ratio of the total kilowatt-
18 hours (kWh) used by the particular jurisdiction in the test year, the twelve month period ending
19 March 2012, to KCPL's total system kWh usage during the test year. Staff applied adjustments
20 to these kWhs to account for losses, certain annualizations and customer growth. Staff has
21 calculated the following energy allocation factors for each jurisdiction:

22	• Missouri Retail Operations:	0.5719
23	• Kansas Retail Operations:	0.4212
24	• Wholesale Operations:	<u>0.0069</u>
25	• Total:	1.0000

26 These jurisdictional demand and energy allocation factors were provided to Staff Witness
27 Cary G. Featherstone, who used them to allocate related costs to the Missouri retail jurisdiction.

28 *Staff Expert/Witness: Alan J. Bax*

1 **C. Application**

2 As stated above, KCPL operates within two state jurisdictions, Missouri and Kansas, and
3 in the wholesale jurisdiction regulated by the FERC. Therefore, it is necessary to identify, then
4 allocate and/or assign, KCPL's specific investments and costs among these three jurisdictions
5 (Missouri Retail, Kansas Retail and Wholesale). To identify KCPL's revenue requirement, Staff
6 must develop KCPL's cost of service for its Missouri retail jurisdiction. To do that KCPL's
7 plant investments and costs in its income statement must be appropriately assigned or allocated
8 to the Missouri retail jurisdiction.

9 To develop KCPL's cost of service for its Missouri retail jurisdiction, Staff began
10 with KCPL's records kept in accordance with FERC accounting requirements per Commission
11 rule. Where these records reflected costs or investments that KCPL incurred solely to serve the
12 Missouri retail jurisdiction, Staff directly assigned those costs or investments to KCPL's
13 Missouri jurisdictional cost of service. However, when it was not appropriate to directly assign
14 costs or investments, Staff allocated those costs using either a demand or energy allocation
15 factor, depending upon whether the investment or cost was incurred more due to demand or more
16 due to energy.

17 KCPL uses its generation and transmission facilities to produce and transport
18 electricity to its Missouri retail customers, Kansas retail customers and wholesale customers
19 (FERC jurisdiction). Because they are primarily sized to meet demand, Staff allocated KCPL's
20 costs and investments in these facilities, as well as the related depreciation reserve accounts, to
21 the two state and one federal jurisdiction on the basis of demand, i.e., with demand allocators.
22 Since KCPL is a four summer month peaking utility, Staff used the 4 CP method to develop the
23 Missouri retail jurisdiction, Kansas retail jurisdiction and wholesale jurisdiction demand
24 allocators. Staff has consistently used the 4 CP method to develop the KCPL demand allocators
25 since KCPL's 1985 Wolf Creek rate case, including each of the four KCPL Regulatory Plan rate
26 cases filed prior to this rate case.

27 In its records kept in accordance with FERC accounting requirements, KCPL separately
28 accounts for its investment in distribution plant located in Kansas and Missouri. Plant identified
29 in this way is referred to as site specific or *situs* plant. Consistent with how KCPL treated
30 distribution plant in its case, Staff used KCPL's actual distribution plant investment in both
31 Missouri and Kansas at March 31, 2012 to develop site specific allocation factors to allocate the

1 total company distribution plant and reserve amounts to quantify only the distribution plant and
2 reserve amounts specific to KCPL's Missouri retail jurisdiction.

3 Using the principle that expenses (costs) should follow plant investment, Staff used the
4 same jurisdictional allocation factors it developed to allocate investment to allocate expenses
5 related to that investment. The FERC expense accounts found in KCPL's income statement
6 (reproduced as Schedule 9 in Staff's Accounting Schedules) include amounts for costs broadly
7 described as production, transmission, "distribution, general and administrative and general
8 ("A&G"). Using the expense accounts found in KCPL's income statement, this principle that
9 expenses should follow plant investment is appropriate because KPCL incurs production
10 (generation) plant expenses to maintain and operate its the generation facilities making it proper
11 to use the same jurisdictional allocator to allocate production plant expense that is used to
12 allocate its generating facilities investment. Similarly, KCPL incurs transmission expenses to
13 maintain and operate its transmission facilities making it appropriate to use the same
14 jurisdictional allocator to allocate transmission expenses that is used to allocate KCPL's
15 investment in its transmission facilities.

16 Staff allocated KPCL's production and transmission costs taken from KCPL's income
17 statement to KCPL's Missouri retail jurisdiction with the same demand allocator Staff developed
18 and used to allocate KCPL's investment in generating and transmission facilities to KCPL's
19 Missouri retail jurisdiction.

20 Staff created the Missouri retail jurisdictional allocation factor for general plant
21 investment, and related costs, based on a composite of the demand allocation factor and the site
22 specific allocation factor. Staff applied the demand allocation factor used to quantify the
23 Missouri jurisdictional share of KCPL's production and transmission costs and the site specific
24 allocation factor used to allocate an appropriate part of KCPL's total company distribution plant
25 and reserve amounts to KCPL's Missouri retail jurisdiction. Staff used the resulting production
26 plant and depreciation reserve amounts and distribution plant costs allocated to KCPL's Missouri
27 retail jurisdiction to form the basis for allocating KCPL's general plant to its Missouri retail
28 jurisdiction. Thus, Staff's Missouri retail jurisdiction allocation factor for KCPL's general plant
29 is based on a composite of the Missouri retail jurisdiction allocation factors Staff developed for
30 KCPL's production, transmission and distribution plant costs. Staff used this composite general

1 plant allocation factor to allocate to KCPL's Missouri retail jurisdiction what are described in
2 KCPL's income statement (Staff Accounting Schedule 9) as "general" costs.

3 Staff also used a variety of jurisdictional allocation factor to allocate the appropriate part
4 of KCPL's administrative and general costs found in KCPL's income statement (Staff
5 Accounting Schedule 9), to KCPL's Missouri retail jurisdiction. Staff relied on KCPL for these
6 allocation factors. Some of these allocation factors are based on the number of KCPL customers
7 in each jurisdiction. Some are based on the number of KCPL employees working in each
8 jurisdiction. Each specific account had a specific allocation factor that Staff used to allocate the
9 appropriate cost to KCPL's Missouri retail jurisdiction.

10 Staff used the energy allocation factor to allocate costs to the Missouri retail jurisdiction
11 that are considered to vary directly with electricity usage. For example, in response to increased
12 demand for electricity, KCPL must either buy or generate more electricity causing one or more
13 of its fuel and purchased power costs to increase—there is a direct relationship in the level of
14 megawatts generated or purchased and the amount of fuel and purchased power costs. In
15 contrast, costs such as fixed capacity, or demand charges are constant regardless of the demand
16 for electricity and, therefore, are allocated using the demand allocator.

17 The rationale for the demand component of a capacity purchase or sale is to recover the
18 fixed costs of the facilities that underlie these transactions. For example, if KCPL sells capacity,
19 KCPL makes a commitment to have generating capacity in place that is dedicated to meeting the
20 load requirements of the customer to whom it is selling the capacity. This is similar to KCPL's
21 requirement to have fixed capacity available to meet the load requirements of its residential,
22 commercial and industrial customers (referred to as its "native load" customers) at every point in
23 time. The demand component of a capacity sale can be thought of as a rate of return on, and of,
24 the asset dedicated for the capacity sale. Similar to when it sells capacity, when KCPL purchases
25 capacity to assure it can meet its load with energy, it will pay a demand component (fixed
26 charge) to the seller. These demand components are assigned or allocated to the jurisdictions
27 with a demand allocator. However, energy sold or purchased using that capacity is a variable
28 cost and is allocated to the jurisdictions with energy allocation factors.

29 KCPL meets its native load with the same generating plant and transmission plant that it
30 uses to generate and transport electricity to make off-system sales—sales to firm and non-firm
31 customers in the bulk power markets (off-system sales). Staff also used the Missouri retail

1 jurisdictional energy allocation factor to allocate KCPL's revenues from off-system sales to its
2 Missouri retail jurisdiction. Since the non-firm, off-system sales market is made up of short-term
3 sales, KCPL does not reserve dedicated capacity for these sales. Traditionally, off-system sales
4 have been allocated using the energy allocation factors since the costs of making these sales are
5 variable in nature, primarily being the cost of the fuel used to generate the electricity sold. As
6 more megawatts are sold, more fuel is consumed or power purchased and, therefore, the higher
7 the fuel cost, or the purchased power cost. These costs vary directly with the megawatt hours
8 sold or purchased and, thus, using energy allocation factors is proper. Staff has used energy
9 allocation factors to allocate off-system sales to KCPL's Missouri retail jurisdiction in each of
10 KCPL's last four rate cases during its Regulatory Plan. Staff consistently used energy allocation
11 factors to allocate off-system sales revenues to the Missouri retail jurisdictions of The Empire
12 District Electric Company and what is now GMO's MPS electric operations for many rate cases
13 dating back to at least the 1990s.

14 *Staff Expert/Witness: Cary G. Featherstone*

15 **XV. Other Miscellaneous Items**

16 **A. Demand-Side Management Cost Recovery**

17 Staff recommends that the Commission order the continuation of the current KCPL DSM
18 regulatory asset account mechanism⁸⁹ in this case to allow full recovery of direct program costs
19 for the Company's eight (8) energy efficiency programs, two (2) demand response programs and
20 one (1) affordability program.

21 The Company first began implementing demand-side management ("DSM") programs as
22 part of its Regulatory Plan approved on July 28, 2005, in Case No. EO-2005-0329. The
23 Regulatory Plan established a Customer Programs Advisory Group ("CPAG") to include Staff,
24 the Office of the Public Counsel, Missouri Department of Natural Resources and other interested
25 parties to serve as a stakeholder advisory group to the Company in the development,
26 implementation, monitoring and evaluation of the Company's demand response, energy

89 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.

1 efficiency and affordability programs. As evidenced by KCPL's quarterly Strategic
2 Infrastructure Investment Status Reports for its Regulatory Plan, the Company's DSM programs
3 have been successful in meeting the overall goals for participation, energy savings and spending
4 levels established in the Regulatory Plan.

5 As a result of the Commission's *Report and Order* in KCPL's last general rate case
6 (Case No. ER-2010-0355), the Regulatory Plan ended on May 14, 2011 with respect to its
7 commitment to implement DSM programs.⁹⁰ However, KCPL continues to offer the same
8 eleven DSM programs to its customers, and the Company's DSM stakeholder advisory group –
9 now called the KCPL DSM Advisory Group - continues to meet quarterly with the Company to
10 provide guidance and support for DSM program development, implementation, monitoring and
11 evaluation.

12 Attached to this Staff Report as Appendix 3, Schedule JAR-1 are pages from the Staff's
13 second Status Report on Energy Efficiency Advisory Groups and Collaboratives⁹¹ which
14 highlight the KCPL DSM stakeholder group process and the challenges and successes to date of
15 the Company's DSM programs. Appendix 3, Schedule JAR-1 also includes a brief description
16 of the Company's eleven DSM programs.

17 KCPL continues its practice - started in early 2010 - of not accepting new applications for
18 its large customer MPower demand-response program⁹². KCPL currently has about 54 MW of
19 voluntary load curtailment under contract for its MPower program. It is noteworthy that due to
20 restrictions at its coal plants along the Missouri River because of flooding in the summer of
21 2011, KCPL signed a contract with Westar Energy, Inc. for additional capacity and energy for
22 the summer of 2011. If KCPL had been accepting new applications, it may not have needed to
23 contract for as much capacity.⁹³

24 The energy and capacity impacts and the overall delivery processes of KCPL's DSM
25 programs are evaluated, measured and verified by third-party contractors of the Company and

90 May 14, 2011 is the effective date of the Commission's May 4, 2011 Report and Order in File No. ER-2010-0355.

91 On January 4, 2012, Staff provided to the Commission in File No. AO-2011-0035 its second annual Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives.

92 MPower Rider Schedule MP contained in KCPL tariff sheets P.S.C.MO. No. 7, Sheet Nos. 21, 21A, 21B, 21C, and 21D.

93 See testimony in this Staff Report by Lena M. Mantle concerning the Westar Energy contract.

1 copies of completed evaluation, measurement and verification (“EM&V”) reports will be
2 provided on “generally a staggered 3-year cycle”⁹⁴ to the KCPL DSM Advisory Group members.
3 All KCPL DSM programs have had a least one EM&V report with both process and impact
4 evaluations.

5 The Regulatory Plan on page 49 specifies:

6 KCPL will accumulate the Demand Response, Efficiency and
7 Affordability Program cost in regulatory asset accounts as the costs are
8 incurred. Beginning with the 2006 Rate Filing, KCPL will begin
9 amortizing the accumulated costs over a ten (10) year period. KCPL will
10 continue to place the Demand Response, Efficiency and Affordability
11 Program costs in the regulatory asset account, and cost for each vintage
12 subsequent to the 2006 Rate Filing will be amortized over a ten (10) year
13 period. Signatories Parties reserve the right to establish a fixed
14 amortization amount in any KCPL rate case prior to June 1, 2010. The
15 amount accumulated in these regulatory asset accounts shall be allowed to
16 earn a return not greater than KCPL’s AFUDC rate. The class allocation
17 of costs will be determined when the amortizations are approved.

18 The Commission’s *Report and Order* in File No. ER-2010-0355 directs that “DSM
19 program costs for investments made from December 31, 2010, until a future recovery
20 mechanism is in place shall be placed in a regulatory asset account and amortized over six years
21 with a carrying cost equal to the AFUDC rate applied to the unamortized balance.” In the same
22 *Report and Order*, the Commission determined that “the unamortized balances of the regulatory
23 asset account shall be included in rate base for determining rates in this case.”⁹⁵

24 Staff recommends that the Commission order the continuation of the current KCPL DSM
25 regulatory asset account mechanism in this case.

26 **1. Missouri Energy Efficiency Investment Act of 2009 (“MEEIA”)**

27 The MEEIA was established in Senate Bill 376⁹⁶ and became law on August 28, 2009.
28 The Commission’s MEEIA rules⁹⁷ became effective May 30, 2011. With the passage of Senate

94 The most recent EM&V reports for all current KCPL DSM programs are included as Schedules ADD-5 through ADD-12 of the direct testimony of Allen D. Dennis filed on December 22, 2011 in File No. EO-2012-0008.

95 Commission’s Report and Order in File No. ER-2010-0355 issued on April 12, 2011 at pages 93 – 94.

96 Section 393.1075, RSMo. Supp. 2010.

97 The Commission’s MEEIA rules include: 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.

1 Bill 376 and the enactment of the MEEIA, the State of Missouri has declared and directed the
2 following:

3 3. It shall be the policy of the state to value demand-side investments
4 equal to traditional investments in supply and delivery infrastructure and allow
5 recovery of all reasonable and prudent costs of delivering cost-effective
6 demand-side programs. In support of this policy, the commission shall:

- 7 (1) Provide timely cost recovery for utilities;
8 (2) Ensure that utility financial incentives are aligned with helping
9 customers use energy more efficiently and in a manner that
10 sustains or enhances utility customers' incentives to use energy
11 more efficiently; and
12 (3) Provide timely earnings opportunities associated with cost-
13 effective measurable and verifiable efficiency savings.

14 4. The commission shall permit electric corporations to implement
15 commission-approved demand-side programs proposed pursuant to this section
16 with a goal of achieving all cost-effective demand-side savings. Recovery for
17 such programs shall not be permitted unless the programs are approved by the
18 commission, result in energy or demand savings and are beneficial to all
19 customers in the customer class in which the programs are proposed,
20 regardless of whether the programs are utilized by all customers.⁹⁸

21 On December 22, 2011, KCPL filed in File No. EO-2012-0008 its *Application for*
22 *Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs*
23 *Investment Mechanism* in which the Company requested Commission approval of the majority of
24 its existing DSM programs and five new DSM programs as MEEIA programs. The Company
25 also requested Commission approval of a demand-side programs investment mechanism
26 (“DSIM”) tracker mechanism pursuant to MEEIA and the Commission’s MEEIA rules. The
27 DSIM tracker would have collected in a regulatory asset the costs directly attributable to the
28 Commission-approved DSM programs, a portion of the overall benefits of the DSM programs to
29 be shared with customers, a reward to the Company for successful implementation of the DSM
30 programs and recovery of lost revenues. On February 17, 2012, KCPL dismissed its *Application*
31 *for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side*
32 *Programs Investment Mechanism* without explanation. However, in the direct testimony of
33 KCPL witness Darrin R. Ives filed on February 27, 2012 in this case, Mr. Ives states:

98 Subsections 393.1075.3 and 4, RSMo. Supp. 2010.

1 As we pulled together this rate request filing and furthered our work on
2 our IRP filings due to be filed in April 2012, we determined it was prudent
3 to reassess our MEEIA filing for KCP&L. Factors we considered were
4 historically low natural gas prices which have created softness in demand
5 in the wholesale market. We also considered the lagging economic
6 environment and the fact that we have experienced declines in weather
7 normalized retail demand since our last case. Considering these factors
8 and with the addition of Iatan 2 to our base load generation fleet, KCP&L
9 does not need additional capacity at this time. As such, to raise customer
10 rates in the short term for benefits customers will realize over a 10 to 20
11 year time horizon just does not make sense considering the current state of
12 the economy. The move to withdraw at this time allows us to leverage
13 one of the most important benefits of energy efficiency, its scalability.⁹⁹

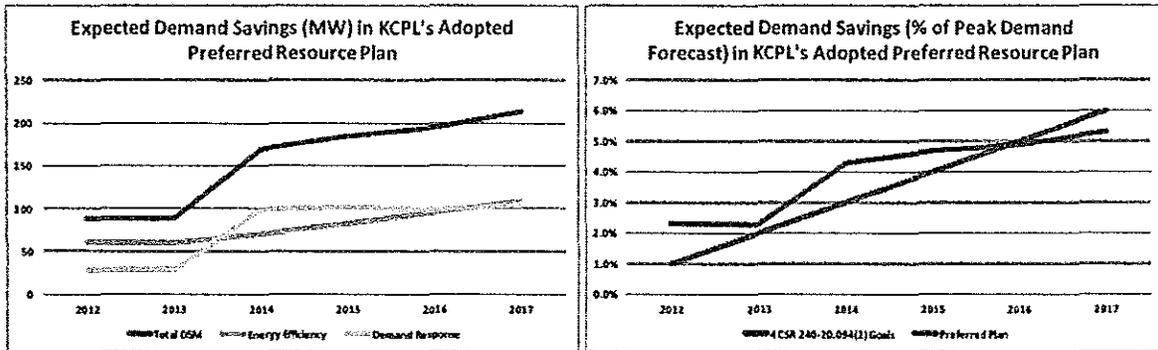
14 **2. Demand-Side Resources in Adopted Preferred Resource Plan**

15 On February 3, 2010, KCPL formally advised the Commission (in File No. EE-2008-
16 0034) that it had determined that “it is appropriate to scale back its demand-side programs in the
17 earlier years of its adopted preferred resource plan due to a reduction in the Company’s load
18 forecast, primarily attributable to the unprecedented economic recession that has affected both
19 customer growth and energy and demand growth in the Company’s service territory.¹⁰⁰” This
20 “scale back” applies only to the new demand-side programs in the Company’s then-adopted
21 preferred resource plan.

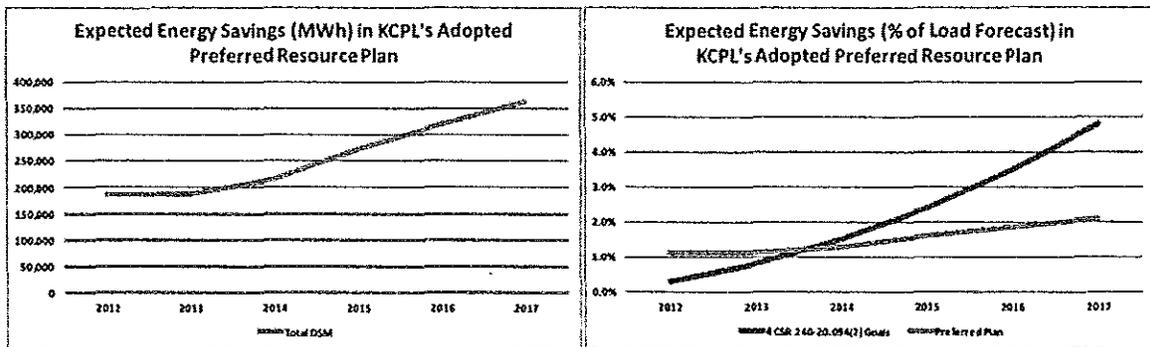
22 On April 9, 2012, KCPL filed its Chapter 22 Electric Utility Resource Planning triennial
23 compliance filing in File No. EO-2012-0323. The Company’s adopted 20-year preferred
24 resource plan includes 20 MW of solar additions, 400 MW of wind additions, the 2016
25 retirement of the 170 MW Montrose Unit 1, and a portfolio of demand-side resources.
26 The following charts show: 1) the expected annual demand savings (MW) due to the Company’s
27 two (2) demand response programs and twelve (12) energy efficiency programs, and 2) the
28 expected cumulative annual demand savings as a percentage of forecasted peak demand and the
29 “soft goals” for cumulative annual demand savings in the Commission’s Rule 4 CSR 240-
30 20.094(2).

99 Direct Testimony of Darrin R. Ives, p 10, ll 9-20.

100 See Item Number 48 filed on February 5, 2010 in File No. EE-2008-0034.



The following charts show: 1) the expected annual energy savings (MWh) due to the Company's twelve (12) energy efficiency programs, and 2) the expected cumulative annual energy savings as a percentage of annual load forecasted and the "soft goals" for cumulative annual energy savings in the Commission's Rule 4 CSR 240-20.094(2).



Staff is conducting its review of KCPL's triennial compliance filing and will file its report not later than September 5, 2012.

Staff Expert/Witness: John A. Rogers

B. Demand-Side Management Program Prudence

1. Historical DSM Program Cost

The Demand-Side Management (DSM) Account 182-440 contains costs that have been incurred for fourteen (14) DSM programs¹⁰¹ that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program, and

¹⁰¹ DSM programs consist of demand response, energy efficiency and affordability programs, including the low income weatherization programs.

1 (2) DSM market research costs. At this time, Staff has no recommended disallowances to the
2 levels of costs charged to KCPL's DSM Account.

3 KCPL's Customer Programs Advisory Group (CPAG) was ordered and approved by the
4 Commission in the stipulation and agreement for KCPL Experimental Regulatory Plan in File
5 No. EO-2005-0329. With the Commission's Report and Order in File No. ER-2010-0355, the
6 KCPL Experimental Regulatory Plan's CPAG requirement ended, and KCPL decided the CPAG
7 name would no longer be used. It is now referred to as the DSM Advisory Group. The KCPL
8 and KCP&L Greater Missouri Operations Company (GMO) DSM Advisory Groups hold joint
9 meetings. Based on Staff's participation in the DSM Advisory Group meetings and Staff's
10 review of the costs in Account 182-440, Staff discovered no evidence of imprudence regarding
11 the level of costs charged to the DSM programs.

12 *Staff Expert/Witness: Hojong Kang*

13 **2. Rate-Making Treatment for the DSM Program Cost**

14 With regard to how DSM past and future costs should be treated, the Commission stated
15 the following in its Report and Order in Case No. ER-2010-0355:

16 One area of agreement is that the —old regulatory assets (Vintages 1, 2,
17 and 3) should be governed by the previous decisions to amortize those
18 regulatory asset accounts over a ten-year period and that amortization
19 period should not change. The Commission also agrees and directs that
20 Vintages 1, 2, and 3 continue to be amortized over a ten-year period.

21 KCP&L agrees with MDNR regarding the treatment for —future
22 investments. The Commission agrees as well and will direct that DSM
23 program costs for investments made from December 31, 2010, until a
24 future recovery mechanism is in place [Vintage 5] shall be placed in a
25 regulatory asset account and amortized over six years with a carrying cost
26 equal to the AFUDC rate applied to the unamortized balance

27 With regard to the —current investments, it would be inconsistent with
28 previous Commission orders to authorize a six-year amortization for the
29 current investments (Vintage 4). The Commission determines that these
30 Vintage 4 investments should continue to be amortized over a ten-year
31 period.

32 The Commission determines that the unamortized balances of the
33 regulatory asset accounts shall be included in rate base for determining
34 rates in this case.

1 Staff reviewed KCPL's adjustment for DSM related costs and confirmed the costs are
2 consistent with the Commission's Report and Order in Case No. ER-2010-0355. Consistent with
3 KCPL's adjustment, Staff included unamortized balances for Vintages 1-5 in its Rate Base
4 Schedule 2 and included annual amortization for each vintage based on a 10 year amortization
5 for Vintages 1-4 and a 6-year amortization for Vintage 5.

6 *Staff Expert/Witness: Karen Lyons*

7 **C. High Efficiency Street and Area Lighting**

8 Staff recommends that KCPL complete the evaluations of its pilot projects' of Light
9 Emitting Diode (LED) Street and Area Lighting ("SAL") systems, and no later than the end of
10 calendar year 2012, file either a compliance LED lighting tariff, or a status report as to when it
11 anticipates filing such tariff. As part of the settlement of certain issues in Case No. ER-2010-
12 0355, KCPL agreed during the February 4, 2011 hearing on the record to "...file by the end of
13 calendar year 2012 either a LED lighting tariff, or when [KCPL] anticipate[s] filing such LED
14 lighting tariff. Also by the end of calendar year 2012, . . . KCPL . . . shall file the results of its
15 LED study, which shall include a review of potential LED lighting health issues.¹⁰²" Staff is not
16 recommending that KCPL offer a LED SAL demand-side program unless KCPL's analysis
17 shows that a LED SAL demand-side program would be cost-effective. However, if a LED SAL
18 demand-side program is not cost-effective, the Staff recommends that the Commission require
19 KCPL to provide its workpapers and analysis to Staff. Staff further recommends that KCPL file
20 a proposed tariff sheet(s) that would provide LED SAL services at cost plus the return authorized
21 by the Commission to its customers.

22 **1. Current Street Lighting for KCPL Missouri**

23 Currently, the Missouri jurisdictional operation of KCPL has approximately 112 public
24 street and highway lighting customers in its service territory, using a total of approximately
25 88,000 MWh annually according to its 2011 Annual Report. Virtually all of the existing
26 installed lighting fixtures in KCPL's service area are high pressure sodium (HPS) lamps, which
27 were determined to be the most efficient and cost-effective available technology for the SAL
28 systems at the time they were installed.

¹⁰² Tr. 34, p. 3715, ll. 24-25; p. 3716, ll. 1-11.

1 **KCP&L LED Pilot.** Through data request responses from KCPL¹⁰⁴, Staff has learned
2 that KCPL and GMO are conducting a LED pilot program with five (5) area communities –
3 Blue Springs, Gladstone, Liberty, and St. Joseph in Missouri and Prairie Village in Kansas –
4 where 44 LED fixtures were installed representing products of six (6) selected vendors.
5 Local communities are interested in learning more about LED lighting and have received
6 pressure from residents to install energy efficient lighting that lowers cost and reduces effects on
7 the environment. The final field report for this LED program evaluation is expected by
8 August 30, 2012¹⁰⁵.

9 **LED Information Sharing with City of Kansas City.** The City of Kansas City,
10 Missouri (“KCMO”) has installed 120 LED fixtures for testing and field measurement of lighting
11 effectiveness. KCPL and KCMO have agreed to share the data and results of their respective
12 LED pilot programs. Staff will review the KCMO final report when it becomes available.

13 Staff will continue to review the KCPL LED SAL systems pilot projects’ evaluation
14 reports as they become available and will update its review and recommendations when
15 appropriate to do so.

16 *Staff Expert/Witness: Hojong Kang*

17 **D. Tariff Issues**

18 KCPL has two electric rate tariffs: P.S.C. Mo. No. 2 that contains the territory description
19 and rules tariff sheets and P.S.C. Mo. No. 7 that contains the rate and rider tariff sheets. These
20 two electric tariffs should be combined into one tariff, P.S.C. Mo No. 8. By combining these
21 two tariffs, a customer of KCPL, Staff, and anyone researching KCPL’s tariff will have access to
22 one tariff, and not have to go back and forth between tariffs when researching or reviewing what
23 services KCPL offers and the rules by which KCPL must abide. When a tariff sheet references
24 another tariff sheet in a different tariff, it can be difficult to find the referenced tariff sheet.

25 When one tariff references another tariff, the customer cannot do a search between the
26 tariffs without difficulty. For ease of use the new tariff should be fully searchable. Currently
27 some pages are searchable and others are not searchable.

¹⁰⁴ Based on the Data Request No. 0390 for Case No. ER-2012-0174.

¹⁰⁵ Based on the Data Request No. 0390.2 for Case No. ER-2012-0174.

1 Staff would work with KCPL to help implement the combined tariff. This work will
2 include making formatting and fonts consistent, removal of tariff sheet language that is no longer
3 in effect, and renumbering of the tariff sheets.

4 Staff recommends the Commission require KCPL to file a new electric rate schedule after
5 the rates go into effect in the current docket. Staff recommends KCPL provide Staff with a
6 proposed draft of the tariff within ninety (90) days after the effective date of rates in the current
7 rate case (Case No. ER-2012-0174). Staff realizes that this detail work takes a lot of time and
8 effort and will work with KCPL to agree to a timeline to accomplish this goal if KCPL does not
9 believe that it can meet this requirement.

10 Staff also recommends the following changes to KCPL's tariff:

- 11 • The following changes should be made because rate area 1 is not defined in
12 the tariff:
 - 13 ○ Small, Medium, Large General Service – All Electric should add
14 (Frozen) to the three GS classes Standby or Breakdown Service
15 (Frozen) – Rate Schedule “1-SA” should delete “1-”
 - 16 ○ Municipal Street Lighting Service (Urban Area) - Rate Schedule
17 “1-ML” KCPL should change it to “ML-U”
 - 18 ○ Municipal Traffic Control Signal Service – Rate Schedule “1-TR”
19 KCPL should change it to “ML-U”
 - 20 ○ Sheet Nos. 35, 35A, 35B, 35C – KCPL should change these sheets
21 from “1-ML” to “ML-U” for Urban Area.
 - 22 ○ Sheet Nos. 37, 37A – 37G - Rate Schedule “1-TR” should delete
23 the “1-”

- 24 • The following changes should be made because rate area 3 is not defined in
25 the tariff:
 - 26 ○ Municipal Street Lighting Service (Suburban Area) - Rate
27 Schedule “3-ML” KCPL should change it to “ML-U”.
 - 28 ○ Sheet Nos. 36, 36A, 36B – KCPL should change these sheets from
29 “3-ML” to “ML-S” for Suburban Area.

- 30 • Municipal Street Lighting Service – LED Pilot. KCPL should renumber
31 tariff sheet Nos. 48, 49, 50 to 48, 48A, 48B to maintain consistency
32 throughout its tariff. KCPL should also delete the reference to Peculiar,
33 Missouri from its tariff because Peculiar is in GMO's service territory.

- 34 • Sheet No. 43Z.1 – Header, Cancelling line, Sheet No. “43.Z1” should read
35 “43Z.1”

36 *Staff Expert/Witness: Thomas M. Imhoff*

1 **E. KCPL Smart Grid Update**

2 This section provides information on the history and status of KCPL's Smart Grid
3 deployment and does not address any particular revenue requirements in this rate case. KCPL is
4 requesting funding for a new group dedicated to maintaining and repairing the Smart Grid
5 electrical infrastructure components as described in the testimony of KCPL witness William P.
6 Herdegen, III.¹⁰⁶ KCPL has invested in upgrading their existing electrical grid infrastructure with
7 Smart Grid components and is also in the process of implementing the Smart Grid demonstration
8 project.¹⁰⁷

9 The KCPL SmartGrid demonstration project (Project) is included in the United States
10 Department of Energy (DOE)¹⁰⁸ and Electric Power Research Institute (EPRI) demonstration
11 programs^{109,110} and is physically located in an economically challenged area of Kansas City,
12 Missouri¹¹¹. The Project goals are to deliver benefits to the Project's end-users, a provide
13 valuable experience and learning opportunity for future applications which includes several
14 items such as; customer acceptance of advanced metering infrastructure (AMI) and time of use
15 (TOU) rates, integration of distributed generation, implementation and testing for a large battery
16 system, substation modernization and integration and identification of various use cases
17 scenarios. The Project is structured as an end-to-end SmartGrid that will include AMI,
18 renewable generation, energy storage resources, leading edge substation and distribution
19 automation and control, energy management interfaces, and innovative customer programs to
20 include TOU rate structures for each summer period May 15th through September 1. Project
21 funding consists of approximately \$48.1 million to be spent from 2010 through 2014, of which
22 \$13.8 million (29%) is KCPL funded, \$10.2 million (21%) is partners/vendors funded and \$24.1
23 million (50%) is federally funded.¹¹²

24 Teaming with KCPL as partners/vendors are Siemens Energy Inc., Open Access
25 Technology, Inc. (OATI), Landis&Gyr AG, GridPoint, Inc., Exergonix (formerly Kokam

¹⁰⁶ Direct Testimony of KCPL witness William P. Herdegen, III, page 2, lines 10-22 and pages 3-5.

¹⁰⁷ <http://www.kcplsmartgrid.com/default.html>.

¹⁰⁸ DOE award number DE-OE0000221.

¹⁰⁹ <http://www.kcplsmartgrid.com/About/SmartGridFactSheet.pdf>.

¹¹⁰ Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.

¹¹¹ www.nlc.org/.../EENR/fact-sheet-kcpl-smart-grid-2011.pdf.

¹¹² KCPL Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

1 America, Inc.), EPRI and Honeywell International, Inc.¹¹³ The engineering firm of Burns and
2 McDonnell is providing engineering services for the Midtown Substation upgrade¹¹⁴.

3 The Project is primarily located in the area served by KCPL's Midtown Substation
4 serving two square miles, impacting about 14,000 commercial and residential customers across
5 ten circuits with a total electrical demand of 69.5 MVA.

6 The SmartGrid project includes over 25 stakeholder groups including, Mid-America
7 Regional Council (MARC), Missouri Electric Cooperative (MEC), Missouri Gas Energy (MGE),
8 University of Missouri at Kansas City (UMKC), Kansas and Missouri Regulatory Agencies, City
9 of Kansas City, Missouri and several local neighborhood groups.¹¹⁵ Within the SmartGrid
10 demonstration project boundaries lies the Green Impact Zone project, a 150 square block area of
11 inner-city neighborhoods in Kansas City, with the primary goal of transforming distressed urban
12 neighborhoods into a sustainable community.¹¹⁶

13 The Project is based upon the guidance found in the proposed National Institute of
14 Standards (NIST) Interim Smart Grid Interoperability Standards Roadmap, the EPRI IntelliGrid
15 Architecture and the GridWise Architectural Council recommendations.¹¹⁷

16 The primary, overall focus for the Project will be to implement next-generation, end-to-
17 end SmartGrid components that will include Distributed Energy Resources (DER), enhanced
18 customer facing technologies, and a distributed-hierarchical grid control system that includes the
19 following key elements:¹¹⁸

- 20 • Upgrade the Midtown Substation to create a next generation "Smart Substation;"
21 with multiple distribution circuits with a variety of feeder based instrumentation
22 and control devices for monitoring and control and a Grid management
23 infrastructure to support the upgraded grid, back office and substation
24 requirements (See Appendix 3, Schedule RSG-1);
- 25 • SmartMeters (14000) with AMI installed at all customer sites to provide
26 consumers with enhanced information on energy use and the opportunity to utilize
27 residential TOU rate structures with an expected participation level of
28 426 residential customers;

¹¹³ KCPL Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

¹¹⁴ <http://burnsmcd.com/>

¹¹⁵ Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.

¹¹⁶ KCPL Green Impact Zone SmartGrid Demonstration Abstract.

¹¹⁷ KCPL Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

¹¹⁸ KCPL Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

- 1 • Integration of distributed generation that includes a Exergonix 1 MW Superior
2 Lithium battery storage system (See Appendix 3, Schedule RSG-1) that was
3 delivered and installed at the Midtown Substation in April of this year;
- 4 • Distributed roof-top solar photovoltaic systems that includes a 100 kW system
5 installed at Paseo High School in November 2011 and a 5kW system at the
6 Midtown Substation;
- 7 • Distributed electrical vehicle charging stations. Currently the Company has
8 20 charging stations at various locations and is monitoring usage patterns. The
9 Company may install additional charging stations depending upon future market
10 developments; and
- 11 • Demonstration House (Project Living Proof)^{119,120} is located at 917 Emanuel
12 Cleaver II Blvd and is open to the public. KCPL has partnered with the
13 Metropolitan Energy Center to showcase products and technology applications that
14 include smart washers and dryers, smart water heaters, roof top solar, battery
15 storage and associated DC to AC inverter, alternative heating and cooling
16 equipment, an electrical vehicle charging station, sustainable landscaping, energy
17 efficiency measures, and devices and web based tools utilized by customers in the
18 Smart Grid demonstration project as described below.

19 Consumers within the Smart Grid demonstration project boundaries will be offered a wide range
20 of products and services with the following expected level of participation:^{121,122}

- 21 • Customers with internet will have access to real time energy usage by viewing a
22 personalized web page via a web portal (“MySmart Portal”);
- 23 • 1,600 residential and commercial customers are expected to have in home/business
24 energy displays (“MySmart Display”) that indicate real-time information and
25 demand response thermostats (“MySmart Thermostat”);
- 26 • 400 residential users are expected to utilize a Energy Management System (EMS);
- 27 • 2 commercial users are expected to utilize a EMS;
- 28 • 10 LED area street lights will be installed at UMKC;
- 29 • 64 residential users are expected to utilize hyper efficient appliances;
- 30 • 5 commercial and 10 residential users are expected to utilize roof-top solar; and

¹¹⁹ <http://kcenergy.org/projectlivingproof.aspx>

¹²⁰ <http://www.kcplsmartgrid.com/openhouse.pdf>

¹²¹ Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.

¹²² <http://www.kcplsmartgrid.com/About/SmartGridFactSheet.pdf>.

- 1 • 10 distributed vehicle charging stations to accommodate Plug in Hybrid Electrical
2 Vehicles (PHEV).

3 KCPL is implementing this demonstration project in the five following project phases:^{123,124}

- 4 1. Project Definition and Compliance to refine project scope, definition and ongoing
5 project management; years 2010-2014.
6 2. Project Design and Performance Baseline compile and/or collect baseline grid and
7 end-use data for the demonstration area; completed.
8 3. Smart Grid Infrastructure Deployment to implement the SmartSubstation, Data
9 Management System (DMS) and Advanced Distribution Automation (ADA)
10 components; Completion scheduled at end of 2012.
11 4. Distributed Energy Resource Deployment to implement the SmartEnd-Use,
12 SmartGeneration (Solar, Battery, PHEV), DER/DR Management components,
13 introduce TOU pilots; Completion scheduled at end of 2012.
14 5. Data Collection, Reporting & Project Conclusion to evaluate system performance;
15 Years 2013-2014.

16 Although not as visible to the public as the Smart Grid demonstration project, there are
17 Smart Grid electrical grid infrastructure components that are being deployed to increase
18 operational and maintenance efficiencies, reduce costs and improve reliability that include the
19 following:¹²⁵

- 20 • Capacitor banks that control or stabilize the system voltage by minimizing voltage
21 drops and absorbing energy from a line spike. The banks provide voltage stability
22 by switching in capacitor banks to provide reactive power when large inductive
23 loads occur, such as when air conditioners, furnaces, dryers, and/or industrial
24 equipment start;
25 • S&C Electric Company SCADAmate® Switching Systems¹²⁶ for pole mounted
26 overhead line circuits;

¹²³ KCPL Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

¹²⁴ Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.

¹²⁵ Direct Testimony of KCPL witness William P. Herdegen, III, page 6, lines 2-20.

¹²⁶ <http://www.sandc.com/products/switching-overhead-distribution/scada-mate-cx.asp>

- 1 • S&C Electric Company IntelliRupter Pulsecloser® reclosers¹²⁷ for electrical fault
- 2 interruption, isolation and circuit restoration. These intelligent reclosers confirm
- 3 that there is not a fault on the circuit prior to reclosing;
- 4 • S&C Electric Company Vista Gear®¹²⁸ that feature circuit load interrupter
- 5 switches and resettable fault interrupters for pad mounted, vault and subsurface
- 6 applications;
- 7 • Communicating or Automated Faulted Circuit Indicators (FCIs). These devices
- 8 provide information on electrical line disturbances and communicate this
- 9 information to system operators in near real time;
- 10 • Intelligent Electronic Device (IED) Radios and Communications;
- 11 • AMI or AMR Communications Equipment; and
- 12 • Meter Communications to other (non-AMI) Devices (Zigbee, etc).

13 In summary, this is an important project for Missouri, since it is the only large scale SmartGrid
14 demonstration project currently planned for Missouri. In addition, because this is an EPRI and
15 DOE demonstration project,¹²⁹ Missouri will receive much exposure.

16 In October of 2011, KCPL hosted the EPRI Smart Grid Demonstration Advisory Group
17 meeting in Kansas City and provided tours of the Smart Grid Demonstration Project.¹³⁰

18 Staff activities to date have consisted of attending presentations and meetings, conducting
19 physical project site reviews, and reviewing documentation and proposed tariffs.

20 All Missouri utilities will also benefit from the project data, lessons learned and
21 evaluation of project performance after the project is completed.

22 *Staff Expert/Witness: Randy Gross*

¹²⁷ <http://www.sandc.com/products/switching-overhead-distribution/intellirupter-pulsecloser.asp>

¹²⁸ <http://www.sandc.com/products/underground-distribution-switchgear/vista.asp>

¹²⁹ http://www.smartgrid.gov/project/kansas_city_power_and_light_green_impact_zone_smartgrid_demonstration

¹³⁰ <http://www.smartgrid.epri.com/doc/EPRI%20Smart%20Grid%20Advisory%20Update%20-%202018-November-2011.pdf>

1 **F. Renewable Energy Standard**

2 **1. Background Information**

3 The Missouri Renewable Energy Standard ("RES")¹³¹ was enacted as a voter initiative
4 petition in November 2008. Provisions of the resulting statute and regulations require Kansas
5 City Power & Light Company ("KCPL") and the other investor-owned utilities to meet certain
6 requirements regarding the use of renewable energy. Beginning January 1, 2010, the RES
7 requires KCPL to provide a rebate (\$2.00 per installed watt)¹³² to its retail customers for
8 installation of solar electric systems on their premises.¹³³ Utilization of a Standard Offer
9 Contract ("SOC") for the purchase of Solar Renewable Energy Certificates ("S-RECs") from
10 customer-owned solar electric systems is optional for the utility companies.¹³⁴ KCPL has not
11 filed SOC tariffs at this time.

12 KCPL filed an application for an Accounting Authority Order ("AAO") associated with
13 RES compliance costs.¹³⁵ That application was resolved through a Non-unanimous Stipulation
14 and Agreement and approved by the Commission on April 30, 2012. The AAO authorized
15 KCPL to: (a) record all incremental operating expenses associated with the cost of solar rebates,
16 the cost to purchase renewable energy credits ("RECs"), the cost of standard offer contracts and
17 other related costs incurred as a result of compliance with the RES; (b) include carrying costs
18 based on the Company's short term debt rate on the balances; and (c) defer such amounts in a
19 separate regulatory asset with the disposition to be determined in KCPL's next general rate case.

20 For calendar years 2011 through 2013, the RES requires KCPL to generate or purchase
21 two percent (2%) of its retail sales using renewable energy resources.¹³⁶ For each portfolio
22 requirement, KCPL must derive two percent (2%) of the requirement from solar energy.¹³⁷
23 Renewable Energy Certificates ("RECs") can be banked for three (3) years and utilized for future
24 compliance purposes.¹³⁸ KCPL filed the required RES Compliance Plans (calendar years 2011

¹³¹ Mo. Rev. Stat. § 393.1020 (2010).

¹³² Mo. Rev. Stat. § 393.1030.3 (2010).

¹³³ The rebate provision has a specific limitation on the size of the system, namely no larger than 25 kilowatts per system.

¹³⁴ 4 CSR 240-20.100 (4)(H)1.

¹³⁵ Case No. EU-2012-0131, this Case also included KCP&L Greater Missouri Operations Company.

¹³⁶ Mo. Rev. Stat. § 393.1030 .1(1) (2010).

¹³⁷ Mo. Rev. Stat. § 393.1030.1 (2010).

¹³⁸ "An unused credit may exist for up to three years from the date of its creation." Mo. Rev. Stat. § 393.1030.2 (2010).

1 and 2012) and RES Compliance Report (calendar year 2011)¹³⁹. Each RES Compliance Plan
2 provides information regarding the utility's plan for the current calendar year and the
3 subsequent two (2) calendar years. The RES Compliance Report is a status report on the
4 utility's compliance for the preceding calendar year. For the 2011 calendar year, KCPL
5 utilized renewable energy and RECs from the Spearville Wind Energy Facility (Spearville 1) for
6 the non-solar requirement and S-RECs from third-party brokers for the solar requirement.¹⁴⁰

7 The State of Kansas has renewable energy requirements also. KCPL will utilize its
8 existing renewable resources, purchased power agreements ("PPA") from renewable resources,
9 and purchased RECs for Missouri RES compliance. In addition to the expenses associated with
10 the items in the previous sentence and solar rebates, there are expenses associated with the
11 Commission-designated REC tracking system¹⁴¹. These expenses include registration,
12 subscription, and volumetric fees. These fees should be easily attributable to the Missouri
13 jurisdictional requirements.

14 RECs from KCPL-owned facilities should be allocated to the Missouri jurisdiction based
15 on an energy allocation basis. Because of the statutory three (3) year REC expiration and the
16 current Missouri RES requirements, KCPL may have an excess of RECs for the Missouri
17 jurisdiction. These excess RECs should be sold (if possible), otherwise the RECs will expire.

18 The Staff continues to monitor File No. EO-2012-0348 concerning KCPL Renewable
19 Energy Standard Compliance Report for calendar year 2011, and its Renewable Energy Standard
20 Compliance Plan for calendar years 2012-2014. The 2012 RES Compliance Plan and 2011 RES
21 Compliance Report case is currently pending and Staff may have additional testimony in rebuttal
22 or surrebuttal based on any decision made by the Commission.

23 *Staff Expert/Witness: Michael E. Taylor*

24 **2. Renewable Energy Costs**

25 Pursuant to 4 CSR 240-20.100 (6)(D), the RES rule provides a recovery option for
26 compliance costs. The rule provides that KCPL may:

¹³⁹ KCPL filed its RES Plan for calendar years 2011-2013 in EO-2011-0277, its RES Plan for calendar years 2012-2014 and RES Report for calendar year 2011 in EO-2012-0348.

¹⁴⁰ EO-2012-0348, *Renewable Energy Standard Compliance Report*, page 4.

¹⁴¹ North American Renewables Registry.

1 ...recover RES compliance costs without the use of a RESRAM through
2 rates established in a general rate proceeding. In the interval between
3 general rate proceedings, the electric utility may defer the costs in a
4 regulatory asset account and monthly calculate a carrying charge on the
5 balance in that regulatory asset account equal to its short-term cost of
6 borrowing. All questions pertaining to rate recovery of the RES
7 compliance costs in a subsequent general rate proceeding will be reserved
8 to that proceeding, including the prudence of the costs for which rate
9 recovery is sought and the period of time over which any costs allowed
10 rate recovery will be amortized.

11 On April 19, 2012, the Commission authorized KCPL's use of an accounting authority
12 order in Case No. EU-2012-0131, to

13 (a) record all incremental operating expenses associated with the cost of
14 solar rebates, the cost to purchase renewable energy credits, the cost of the
15 standard offer and other related costs incurred as a result of compliance
16 with Missouri's Renewable Energy Standard Law in USOA Account 182;
17 (b) include carrying costs based on the Compan[y's] short term debt rate
18 on the balances in those regulatory assets; and (c) defer such amounts in a
19 separate regulatory asset with the disposition to be determined in the
20 Compan[y's] next general rate cases.¹⁴²

21 Discussions continue with the Company concerning the level of RES costs through
22 March 31, 2012. Staff recommends reflecting in the cost of service an annualized level of RES
23 expenditures over the twelve month period ending March 31, 2012, to be included in rates. In
24 addition, Staff has included a three (3)-year amortization of deferred RES costs. As part of its
25 true-up audit, Staff will continue to examine RES costs through August 31, 2012, and any
26 Commission decision in File No EO-2012-0348, and make additional adjustments as needed to
27 the level for inclusion in permanent rates.

28 *Staff Expert/Witness: Karen Lyons*

29 **G. Energy Independence and Security Act of 2007 (EISA)**

30 On December 19, 2007, the Energy Independence and Security Act of 2007 ("EISA"),
31 which amended various sections of the Public Utility Regulatory Policies Act of 1978
32 ("PURPA"), was signed into law. PURPA's purposes are to encourage: 1) conservation of
33 electric energy, 2) efficiency in the use of facilities and resources by electric utilities, and

¹⁴² File No. EU-2012-0131, *Order Approving And Incorporating Stipulation And Agreement*, p. 2.

1 3) equitable rates to consumers of electricity.¹⁴³ EISA established four additional PURPA
2 standards for electric utilities as follows: Integrated Resource Planning (IRP), Rate Design
3 Modifications to Promote Energy Efficiency Investments, Consideration of Smart Grid
4 Investments, and Smart Grid Information.

5 On December 15, 2008, Staff filed requests for the Commission to open dockets for the
6 purpose of establishing records for consideration and determination as to whether it is
7 appropriate to implement the new standards encompassed within EISA to carry out the above
8 noted purposes. EISA establishes timeframes within which the Commission is to perform this
9 consideration and determination. The Commission should begin consideration within one year
10 after enactment of the standard (i.e., by December 19, 2008) and complete its consideration and
11 determination no later than two years after enactment (i.e., by December 19, 2009). Absent such
12 determination, the Commission should consider in a general rate case for each individual electric
13 utility whether or not it is appropriate to implement such standard to carry out the above noted
14 purposes. Should the Commission decline to implement a PURPA standard for which it
15 determines the standard is appropriate to carry out the above-noted purposes, the Commission is
16 directed to state in writing its reasons.

17 In response to Staff's request, the Commission opened the following dockets in
18 accordance with the mis-numbering of the four new standards as had occurred in the original
19 EISA legislation:

- 20 1) Case No. EW-2009-0290: In the Matter of the Consideration of Adoption
21 of PURPA **Section 111(d)(16)** Smart Grid Investments Standard as
22 Required by Section 532 of the Energy Independence and Security Act of
23 2007. ("Smart Grid Investment Docket")
- 24 2) File No. EW-2009-0291: In the Matter of the Consideration of Adoption
25 of the PURPA **Section 111(d)(16)** Integrated Resource Planning Standard
26 as Required by Section 532 of the Energy Independence and Security Act
27 of 2007. ("IRP – Docket")
- 28 3) File No. EW-2009-0292: In the Matter of the Consideration of Adoption
29 of the PURPA **Section 111(d)(17)** Rate Design Modifications to Promote
30 Energy Efficiency Investments Standard as Required by Section 532 of the
31 Energy Independence and Security Act of 2007. ("Rate Design Docket")

¹⁴³ PURPA Section 101.

1 4) Case No. EW-2009-0293: In the Matter of the Consideration of Adoption
2 of PURPA Section 111(d)(17) Smart Grid Information Standard as
3 Required by Section 1307 of the Energy Independence and Security Act of
4 2007. (“Smart Grid Information Docket”).

5 It is my understanding that Congress corrected the mis-numbering of the four new EISA
6 standards in Section 408, Technical Corrections, as enacted as part of the American Recovery
7 and Reinvestment Act of 2009.¹⁴⁴ By May 6, 2009, the Commission issued orders correcting the
8 numbering of the four new PURPA standards and re-numbered and consolidated the workshop
9 dockets as follows:

- 10 1) File No. EW-2009-0290: In the Matter of the Consideration of Adoption
11 of the PURPA Section 111(d)(16) Integrated Resource Planning Standard
12 as Required by Section 532 of the Energy Independence and Security Act
13 of 2007. (“IRP Docket”);
- 14 2) File No. EW-2009-0291: In the Matter of the Consideration of Adoption
15 of the PURPA Section 111(d)(17) Rate Design Modifications to Promote
16 Energy Efficiency Investments Standard as Required by Section 532 of the
17 Energy Independence and Security Act of 2007. (“Rate Design Docket”);
- 18 3) File No. EW-2009-0292: In the Matter of the Consideration of Adoption
19 of PURPA Section 111(d)(18), Smart Grid Investments Standard, and
20 PURPA Section 111(d)(19), Smart Grid Information Standard as
21 Required by Section 1307 of the Energy Independence and Security Act of
22 2007. (“Smart Grid Docket”).

23 On November 23, 2009, the Commission issued its *Order Finding Consideration /*
24 *Implementation Of New Federal Standards Through Workshop And Rulemaking Procedures Is*
25 *Required* in File Nos. EW-2009-0290, EW-2009-0291, and EW-2009-0292. The Commission
26 stated in its order at page 5, “The Commission has satisfied the requirements for consideration of
27 the new EISA standards, and on the basis of the quasi-legislative record created in these
28 workshops, the Commission determines that no comparable standards have been considered that
29 would constitute prior state action and prohibit the Commission from taking any further action in
30 relation to the new EISA standards.”

¹⁴⁴ Pub. L. No. 110-140, 121 Stat. 1492 (2007), amended by Section 408 of The American Recovery and Reinvestment Act of 2009 (the EISA, prior to this amendment, is codified at 16 USCS 2621 and 2622 (Cum. Supp. 2008)). PURPA is codified generally in 16 USCS 2601 et seq., but various provisions appear elsewhere in the United States Code.

1 Since there has been no specific determination to date by the Commission, Staff
2 recommends the Commission consider each standard and make its determination with respect to
3 KCPL in this rate case based on the following discussion.

4 **IRP Docket**

5 **PURPA Section 111(d)(16)**, Integrated Resource Planning Standard as required by
6 Section 532 of the Energy Independence and Security Act of 2007, requires state commission
7 consideration of whether to implement the following:

8 (A) integrate energy efficiency resources into utility, State, and
9 regional plans; and

10 (B) adopt policies establishing cost-effective energy efficiency as a
11 priority resource.

12 Staff held several workshops, which culminated in the Commission's promulgation of a
13 rulemaking in File No. EX-2010-0254, In the Matter of a Proposed Rulemaking Regarding
14 Revision of the Commission's Chapter 22 Electric Utility Resource Planning Rules. The revised
15 Chapter 22 rules became effective on June 30, 2011, which require the screening and integration
16 of cost-effective energy efficiency resources to be included in the electric utility resource
17 planning process. After opportunity for input from the public which included comments being
18 submitted by the electric utilities, Office of the Public Counsel, Missouri Department of Natural
19 Resources, Renew Missouri, Great Rivers Environmental Law Center, and Dogwood Energy,
20 LLC, the Commission approved the policy in Chapter 22 of requiring demand-side resources be
21 evaluated on an equivalent basis with supply-side resources subject to compliance with all legal
22 mandates.¹⁴⁵

23 In addition, the Commission has a workshop docket, Case No. EW-2010-0187, opened to
24 investigate how to achieve its statutory responsibilities under the Missouri Energy Efficiency
25 Investment Act ("MEEIA"), Section 393.1075, RSMo., within the background of Federal Energy
26 Regulatory Commission ("FERC") policies that eliminate barriers to demand response and that
27 direct the Midwest Independent Transmission System Operator ("MISO") and the Southwest
28 Power Pool ("SPP") to accommodate state policy regarding retail customer demand-side activity.
29 This docket was opened to explore the best model or models to achieve the requirements of the

¹⁴⁵ 4 CSR 240-22.010(2)(A)

1 MEEIA through state demand-side programs, wholesale market opportunities available in MISO
2 or SPP, or possible hybrid approaches, and the implications for resource planning under various
3 approaches. The roles for utilities, aggregators of retail consumers (“ARCs”), customers in all
4 classes, and other stakeholders in designing the appropriate means of achieving Missouri’s
5 policy objectives, and for interacting with MISO and SPP are also to be evaluated.

6 While not specifically making a determination to implement PURPA Section 111(d)(16),
7 the Commission has promulgated rulemakings to address the principles of that section; therefore,
8 Staff suggests there is nothing that remains for the Commission to determine in response
9 to PURPA Section 111(d)(16), and recommends the Commission make such a finding in this
10 rate case.

11 Rate Design Docket

12 **PURPA Section 111(d)(17)**, Rate Design Modifications to Promote Energy Efficiency
13 Investments Standard as required by Section 532 of the Energy Independence and Security Act
14 of 2007, requires state commissions to consider whether to implement: 1) removing the
15 throughput incentive and disincentives to energy efficiency; 2) providing utility incentives for
16 successful management of energy efficiency programs; 3) including the impact of energy
17 efficiency as one of the goals of retail rate design; 4) adopting rate designs that encourage energy
18 efficiency; 5) allowing timely recovery of energy efficiency related costs; and 6) offering energy
19 audits, demand-response programs, publicizing the benefits of home energy efficiency
20 improvements and educating homeowners about Federal and State incentives. Similarly, in
21 2009, Governor Jeremiah “Jay” Nixon signed Senate Bill 376, the “Missouri Energy Efficiency
22 Investment Act,” with a stated policy to “value demand-side investments equal to traditional
23 investments in supply and delivery infrastructure and allow recovery of all reasonable and
24 prudent costs of delivering cost-effective demand-side programs.” Section 393.1075.3

25 The Commission held several workshops, which culminated in the promulgation of a
26 rulemaking in File No. EX-2010-0368, In the Matter of the Consideration and Implementation of
27 Section 393.1075, The Missouri Energy Efficiency Investment Act (“MEEIA”). The rules
28 became effective on May 30, 2011 – Rules 4 CSR 240-20.093, 20.094, 3.163, and 3.164. KCPL
29 submitted its MEEIA application on December 22, 2011, in Case No. EO-2012-0008. On
30 February 17, 2012, KCPL filed its Notice of Dismissal. The case was subsequently closed on
31 March 6, 2012. Although KCPL withdrew its MEEIA filing, the Commission has in place the

1 framework necessary for the Commission to make a determination on the associated PURPA
2 principles as outlined above.

3 SB 376 contains a provision which states, "Prior to approving a rate design modification
4 associated with demand-side cost recovery, the commission shall conclude a docket studying the
5 effects thereof and promulgate an appropriate rule." Section 393.1075.5. The Commission held
6 additional workshops on this provision of SB 376, and on March 20, 2012, Electric Utility
7 Consultants, Inc. ("EUCI"), provided to the Commission, Staff and interested stakeholders, an
8 in-house, specialized training course on Electric Rate Design Modifications Associated with
9 Demand-Side Cost Recovery.

10 The revised Chapter 22 rules incorporate requirements for rate design analysis. For
11 instance, 4 CSR 240-22.030(5)(C) requires, at a minimum, that load forecast models assess the
12 impact of legal mandates, economic policies, and rate designs on future energy and demand
13 requirements. Likewise, 4 CSR 240-22.050(4)(B) requires the utility to describe and document
14 its demand-side rate planning and design process, and when appropriate, to consider multiple
15 demand-side rate designs for the major classes.

16 The Commission sets rates in Missouri based on the cost to serve the customer. This
17 gives the customer accurate cost information on which it can determine whether or not it wants
18 to implement energy efficiency measures. Increasing rates to encourage energy efficiency or
19 setting rates lower for customers that implement energy efficiency sends inaccurate costs signals
20 to the customers. Therefore, without getting into a discussion of general ratemaking principles,
21 but for purposes of the Commission's consideration as to whether it should implement PURPA
22 Section 111(d)(17), setting rates based on cost to serve the customer sends the appropriate price
23 signal to the customer to make decisions on energy efficiency. The Commission's revised
24 Chapter 22 rules require the electric utilities to look at all forms of incentivizing energy
25 efficiency including home energy audits and demand-response programs.

26 As a result of these activities, Staff recommends that the Commission, in this case, make
27 a determination that, although additional activities related to SB 376 are contemplated, no further
28 determination is needed in response to PURPA Section 111(d)(17) for KCPL.

29 Smart Grid Docket

30 In response to PURPA Section 111(d)(18), Smart Grid Investments Standard, and
31 PURPA Section 111(d)(19), Smart Grid Information Standard, as required by Section 1307 of

1 the Energy Independence and Security Act of 2007, the Commission, on December 29, 2010,
2 issued an order to open File No. EW-2011-0175 as a repository for information concerning the
3 Smart Grid in Missouri.

4 On January 13, 2011, Staff filed the *Missouri Smart Grid Report* ("Report") in File No.
5 EW-2011-0175. The Report discusses Smart Grid technologies, provides a status update on
6 various Smart Grid opportunities in Missouri and presents issues and concerns related to Smart
7 Grid deployment. It identifies key issues requiring further emphasis, including planning,
8 implementation, cost recovery, cybersecurity and data privacy, customer acceptance and
9 involvement, and customer savings and benefits. The Report recommends the Commission hold
10 a Smart Grid workshop every six months for information exchange and sharing of best practices
11 and educational opportunities; and also recommends the Commission open a docket to address
12 cost recovery issues.

13 The Commission held Smart Grid conferences on June 28, 2010, and November 29,
14 2011. Panelist and speaker topics included such items as updates on Smart Grid projects in
15 Missouri, customer views, education and engagement, and challenges to deployment.

16 The information provided in the workshop is provided to the public through the
17 Commission's electronic filing and information system. The Smart Grid was also the most
18 recent subject of the *PSCConnection*, a publication of the Commission which is available online,
19 at public hearings, at the State Fair booth, and at all other opportunities where the Commission
20 interacts with the public.

21 On July 17, 2012, the Commission issued its *Order Directing Notice and Directing*
22 *Filing* in File No. EW-2013-0011. The Commission noted, the electric power industry is
23 increasingly incorporating information technology (IT) systems and networks into existing
24 infrastructure, but the increased reliance on IT systems and networks exposes the grid to
25 cybersecurity vulnerabilities. The Commission is charged with assuring public utility companies
26 provide safe and adequate service at just and reasonable rates. The Commission issued its Order
27 to gather information related to cyber vulnerabilities and the integrity of the electric utilities'
28 internal cybersecurity practices. All Missouri regulated electric utilities are required to file
29 answers to all questions contained in the Order by August 31, 2012. This provides yet another
30 opportunity for the Commission to explore issues and take action related to the PURPA standard.

1 PURPA Section 111(d)(19) requires all electricity purchasers and other interested parties
2 to be provided access to information from their electricity provider related to time-based prices,
3 usage, and sources of power provided by the utility and type of generation, with associated
4 greenhouse gas emissions for each type of generation, to the extent such information is available,
5 on a cost-effective basis. While the Commission has not specifically addressed these issues in
6 the context of PURPA Section 111(d)(19), there have been several forums in which stakeholders
7 have discussed related issues and Staff recommends these issues continue to be addressed as they
8 arise. In addition, the Commission and Staff monitor KCPL's activities related to the Green
9 Impact Zone and KCPL's American Recovery and Reinvestment Act Smart Grid implementation
10 in the Kansas City area.

11 Staff recommends the Commission make a determination in this case that it has
12 established the appropriate avenues for monitoring Smart Grid activities and no greater ongoing
13 activity is needed in response to PURPA Section 111(d)(18) and PURPA Section 111(d)(19) in
14 the context of KCPL.

15 *Staff Expert/Witness: Natelle Dietrich*

16 **XVI. Transition Cost Recovery Mechanism**

17 **A. Acquisition Transition Cost Recovery**

18 On April 4, 2007, Great Plains, KCPL and Aquila filed an application with the
19 Commission seeking authority for a series of transactions whereby Aquila would become a
20 direct, wholly-owned subsidiary of Great Plains. On July 1, 2008, in Case No. EM-2007-0374
21 ("Acquisition Case"), the Commission granted that authority. On July 14, 2008 Great Plains
22 completed the acquisition.

23 In Commission's Report and Order for the acquisition case, at page 282, in ordered
24 paragraph 6(C), the Commission included the following condition:

25 c. Great Plains Energy, Incorporated, Kansas City Power & Light
26 Company and Aquila, Inc., shall, upon closure of the authorized
27 transactions, implement a synergy savings tracking mechanism as
28 described by the Applicants, and in the body of this order, utilizing a base
29 year of 2006;

30 The Commission found that there was potential for significant savings as a result of the
31 acquisition, and was supportive of Great Plains, KCPL and Aquila recovering the costs they

1 incurred in combining the operations of KCPL and Aquila. These costs are referred to as
2 “transition costs” and include non-executive severance costs for employees terminated as a result
3 of the acquisition, facilities’ integration costs, and incremental third-party and other non-labor
4 expenses incurred to support the integration of the operations of KCPL and Aquila.

5 The Commission also addressed costs referred to as transaction costs—costs to complete
6 the acquisition such as investment banking fees, legal costs preparing legal documents to
7 complete the acquisition. In the section of its Report and Order where it presented its “Final
8 Conclusions Regarding Transaction and Transition Cost Recovery,” on page 241, the
9 Commission stated:

10 Substantial and competent evidence in the record as a whole supports the
11 conclusions that: (1) the Applicants’ calculation of transaction and
12 transition costs are accurate and reasonable; (2) in this instance,
13 establishing a mechanism to allow recovery of the transaction costs of the
14 merger would have the same effect of artificially inflating rate base in the
15 same way as allowing recovery of an acquisition premium; and (3) the
16 uncontested recovery of transition costs is appropriate and justified. The
17 Commission further concludes that it is not a detriment to the public
18 interest to deny recovery of the transaction costs associated with the
19 merger and not a detriment to the public interest to allow recovery of
20 transition costs of the merger.

21 If the Commission determines that it will approve the merger when it
22 performs its balancing test ..., the Commission will authorize KCPL and
23 Aquila to defer transition costs to be amortized over five years. (Footnote
24 omitted.)

25 In the footnote omitted above (footnote 930), the Commission stated:

26 The Commission will give consideration to their [transition costs]
27 recovery in future rate cases making an evaluation as to their
28 reasonableness and prudence. At that time, the Commission will expect
29 that KCPL and Aquila demonstrate that the synergy savings exceed the
30 level of the amortized transition costs included in the test year cost of
31 service expenses in future rate cases.

32 In the 2010 Rate Case the Commission determined the appropriate amount of acquisition
33 transition costs to include in KCPL’s rates. The Commission ordered recovery of the transition
34 costs over five years beginning with the effective date of rates in the 2010 Rate Case. KCPL and
35 GMO have not deferred any additional transition costs after December 31, 2010. Below are the
36 total unamortized transition costs, the total direct rate recovery at January 31, 2013, and the

1 balance at January 31, 2013. The projected effective date of rates in the current 2012 Rate Cases
2 is January 27, 2013.

Total Acquisition Transition Costs at January 31, 2013	
	January 31, 2013
KCPL - MO	
Total Unamortized Transition Costs	\$ 19,344,018
Total Direct Rate Recovery	6,770,406
Balance At Date	12,573,611
GMO - MPS	
Total Unamortized Transition Costs	17,727,367
Total Direct Rate Recovery	5,672,758
Balance At Date	12,054,610
GMO - L&P	
Total Unamortized Transition Costs	4,452,471
Total Direct Rate Recovery	1,424,791
Balance At Date	3,027,680
Summary All Jurisdictions	
Total Unamortized Transition Costs	41,523,856
Total Direct Rate Recovery	13,867,954
Balance At Date	27,655,902

4
5 Directly through the cost of service through rates, KCPL and GMO will recover
6 \$13.8 million in transition costs through the effective date of rates in this case. The total
7 unamortized balance for all jurisdictions is \$27.6 million at January 2013 (see above table).

8 As part of its *Report and Order* in the Findings of Fact concerning this issue in the
9 2010 Rate Case, the Commission found the following:

10 441. In Missouri, it is well established that there is a lag between when
11 a cost or revenue is incurred and when that cost or revenue is reflected in
12 rates. This is known as regulatory lag. [footnote omitted]

13 442. As a result of regulatory lag, if a utility experiences a cost
14 decrease, there is a lag in time until that reduced cost is reflected in rates.
15 During that lag, the Company shareholders reap, in the form of increased
16 earnings, the entirety of the benefit associated with reduced costs. The
17 Company shareholders also reap, in the form of decreased earnings, the
18 entirety of the loss associated with increased costs.

1 The Commission restated in its 2010 Case Order Findings of Fact what it had stated in its
2 Acquisition Case Order concerning recovery of transition costs:

3 444. The Commission qualified its authorization by stating that, "The
4 Commission will give consideration to ...[the transition costs] recovery in
5 future rate cases making an evaluation as to their reasonableness and
6 prudence. At that time, the Commission will expect that KCP&L and
7 Aquila demonstrate that the synergy savings exceed the level of the
8 amortized transition costs included in the test year cost of service expenses
9 in future rate cases." [footnote omitted] The Commission contemplated
10 that the recovery would only happen if the synergy savings were greater
11 than the costs to achieve those savings. [footnote omitted]

12 The Commission, in both the Acquisition Order, and in its 2010 Case Order, relied upon
13 the Synergy Tracking Model that in the Acquisition Case it ordered be used as shown in the
14 finding in its 2010 Case Order that follows:

15 449. The Companies developed and maintained a Synergy Tracking
16 Model which demonstrated that the merger synergy savings for non-fuel
17 operations and maintenance expense exceed the amortization of merger
18 transition costs. [footnote omitted]

19 In the same Order, the Commission noted Staff's analysis of the Commission-ordered
20 Synergy Savings Tracking Model:

21 451. Staff performed an analysis of both the Commission ordered
22 synergy savings tracking model and KCP&L created synergy project
23 charter database. Staff's analysis showed that the amount of synergies in
24 the synergy project database exceeded those in the Commission-ordered
25 tracking system. [footnote omitted]

26 When reading Findings of Fact 444, 449, and 451 above in the 2010 Case Order, the
27 Commission relied upon, in part, the results of the Commission Ordered Synergy Savings
28 Tracking Model. However, according to its response to Data Request 195.1 in Case No.
29 ER-2012-0174, KCPL has not maintained the Commission Ordered Synergy Savings Tracking
30 Model:

31 KCP&L has not maintained the synergy tracking model that the
32 Commission ordered to demonstrate that amortization of transition costs
33 should begin. KCP&L has continued to track synergies internally using
34 the charter database provided in the response to data request 196 in the
35 current case (ER-2012-0174).

1 The relevance of an updated Commission Ordered Synergy Savings Tracking Model lies
2 in what the model was designed to demonstrate. In Case No. ER-2010-0355, the model KCPL
3 provided compared the adjusted base year of non-fuel operations and maintenance (non-fuel
4 O&M) of standalone KCPL and Aquila operations in calendar year 2006 to the combined KCPL
5 and GMO operations of calendar year 2009, the test year in the 2010 Case. The model
6 demonstrated that the annual synergies realized amounted to \$48.5 million. The Commission
7 relied upon this model, as contemplated in its Acquisition Case Order, specifically in footnote
8 930, to give consideration of transition cost recovery in future rate cases. The Commission
9 specifically relied upon the results of this model in its Findings of Fact in its 2010 Case Report
10 and Order that it made in Finding of Fact No. 455:

11 455. The synergy savings exceed the level of the amortized costs.
12 [footnote omitted]

13 The above omitted footnote, No. 604, referenced three documents, the Direct Testimony
14 of KCPL witness Darrin Ives, the Rebuttal Testimony of Staff witness Keith Majors, and the
15 hearing transcript at page 3472. The Commission, in consideration of testimony and hearings,
16 found in its Finding of Fact No. 455 that the Commission Ordered Synergy Savings Tracking
17 Model demonstrated “[t]he synergy savings exceed the level of the amortized costs.”

18 The Commission, in its Conclusions of Law No. 41 in the 2010 Case Order reiterated its
19 consideration of the Commission Ordered Synergy Savings Tracking Model as follows:

20 41. ...[T]he Commission reserved consideration of recovery of the
21 transition costs when it said:

22 The Commission will give consideration to their [transition costs]
23 recovery in future rate cases making an evaluation as to their
24 reasonableness and prudence. At that time, the Commission will expect
25 that KCP&L and Aquila demonstrate that the synergy savings exceed the
26 level of the amortized transition costs included in the test year cost of
27 service expenses in future rate cases. [Footnote 930 omitted]

28 KCPL has not maintained the Commission Ordered Synergy Savings Tracking Model. In
29 the 2010 KCPL Case, the Commission relied upon, among other things, this very model in its
30 decision to amortize the transition costs and include the annual amortization amounts in the
31 revenue requirements of KCPL and GMO. While KCPL has maintained its Synergy Charter
32 Tracking Database for recording cumulative synergy savings, without the Commission Ordered
33 Synergy Savings Tracking Model, Staff cannot determine whether the annual synergy savings,

1 from an adjusted 2006 base year compared to the Commission-ordered test year in this case
 2 ending September 30, 2011, exceed the amortized transition costs.

3 While KCPL has not maintained the Commission Ordered Synergy Savings Tracking
 4 Model, there is evidence that KCPL's administrative and general (A&G) expenses continue to
 5 increase and be the highest per average customer, per megawatt hour sold, and per dollar of
 6 electric operating revenue of all the electric utilities this Commission rate regulates. Staff's
 7 analysis used information directly from the FERC Form 1, in the form of Annual Reports to the
 8 Commission from its EFIS system and information from the Westar Energy FERC Form 1.

9 Staff presented an analysis of Administrative & General expenses in the 2010 Rate Case,
 10 and the Commission considered it in its Finding of Fact 458:

11 458. Staff did an analysis of the Companies' Administrative & General
 12 (A&G) expenses and other electric utilities in the region. [footnote
 13 omitted] Staff's analysis indicates that on a combined company basis,
 14 KCP&L and GMO have the highest A&G expenses per customer, per
 15 megawatt hour sold and per dollar of operating revenue. [footnote
 16 omitted]

17 As can be seen below, KCPL and GMO's Administrative & General expenses remain
 18 pervasively high. The tables below are the detail and summaries of Staff's analysis:

19

Administrative & General Expenses per Average Customer						
				Combined	Ameren	
Calendar	Empire	GMO	KCPL	KCPL and	Missouri	
2011				GMO	MO Basis	Westar
A&G Expenses	36,912,783	70,505,022	173,703,809	244,208,831	275,200,772	94,161,548
Average Number of Customers	166,236	312,716	512,125	824,841	1,190,483	369,168
A&G Cost per Customer	\$222.05	\$225.46	\$339.18	\$296.07	\$231.17	\$255.06

1

Administrative & General Expenses per Megawatt Hour Sold						
				Combined	Ameren Missouri	
Calendar 2011	Empire	GMO	KCPL	KCPL and GMO	MO Basis	Westar
A&G Expenses	36,912,783	70,505,022	173,703,809	244,208,831	275,200,772	94,161,548
Megawatt Hours Sold	5,815,365	8,520,415	20,374,582	28,894,997	48,142,970	17,499,665
A&G Cost per Megawatt Hour Sold	\$6.35	\$8.27	\$8.53	\$8.45	\$5.72	\$5.38

2

Administrative & General Expenses per Electric Operating Revenue						
				Combined	Ameren Missouri	
Calendar 2011	Empire	GMO	KCPL	KCPL and GMO	MO Basis	Westar
A&G Expenses	36,912,783	70,505,022	173,703,809	244,208,831	275,200,772	94,161,548
Total Electric Operating Revenues	522,506,506	759,742,827	1,558,265,703	2,318,008,530	3,226,611,565	1,240,125,727
A&G Cost Per Electric Revenue Dollar	\$0.0706	\$0.0928	\$0.1115	\$0.1054	\$0.0853	\$0.0759

3

4

5

6

7

8

9 *continued on next page*

10

11

12

13

14

Three Year Analysis of FERC Form 1 Administrative & General Expenses							
	SUMMARY	Empire	GMO	KCPL	Combined KCPL and GMO	Ameren Missouri Basis	Westar
2009	A&G Cost per Customer	\$170.09	\$214.65	\$278.43	\$254.23	\$211.03	\$223.55
2010	A&G Cost per Customer	\$194.16	\$198.10	\$298.54	\$260.45	\$201.85	\$252.38
2011	A&G Cost per Customer	\$222.05	\$225.46	\$339.18	\$296.07	\$231.17	\$255.06
2009	A&G Cost per Megawatt Hour Sold	\$5.28	\$8.26	\$7.08	\$7.42	\$5.11	\$4.76
2010	A&G Cost per Megawatt Hour Sold	\$5.46	\$7.02	\$7.10	\$7.07	\$4.98	\$5.17
2011	A&G Cost per Megawatt Hour Sold	\$6.35	\$8.27	\$8.53	\$8.45	\$5.72	\$5.38
2009	A&G Cost Per Dollar of Electric Revenue	\$0.0660	\$0.1035	\$0.1079	\$0.1064	\$0.0926	\$0.0768
2010	A&G Cost Per Dollar of Electric Revenue	\$0.0678	\$0.0838	\$0.1007	\$0.0952	\$0.0793	\$0.0772
2011	A&G Cost Per Dollar of Electric Revenue	\$0.0706	\$0.0928	\$0.1115	\$0.1054	\$0.0853	\$0.0759

2

3

4

5

In comparison to Empire District Electric, Ameren Missouri, and Westar Energy, KCPL and GMO combined have the highest A&G cost per customer, per megawatt hour sold, and per dollar of electric revenue.

6

7

8

9

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 recorded results as of March 31, 2012 are in the table below:

1

Synergy Project Charter Tracking Database Synergy Savings		
Period	Regulated Savings	Corporate Savings
Q3 2008	\$7,049,467	\$17,927,511
Q4 2008	13,565,146	31,022,978
2008 Total	20,614,612	48,950,489
Q1 2009	11,267,258	19,189,044
Q2 2009	14,296,977	19,062,379
Q3 2009	19,711,085	19,427,888
Q4 2009	19,286,671	20,322,463
2009 Total	64,561,991	78,001,774
Q1 2010	15,875,340	20,518,886
Q2 2010	19,753,175	20,570,612
Q3 2010	27,383,306	20,479,083
Q4 2010	20,012,168	20,110,478
2010 Total	83,023,990	81,679,059
Q1 2011	22,074,830	20,387,105
Q2 2011	18,409,043	20,136,282
Q3 2011	19,200,838	19,369,300
Q4 2011	23,388,668	20,194,446
2011 Total	83,073,379	80,087,134
Q1 2012	18,221,284	17,273,394
2012 Total	18,221,284	17,273,394
Cumulative Total	\$269,495,257	\$305,991,850
Projected Q2-Q4 2012	58,598,389	54,792,881
Projected 2013	36,575,418	34,934,170
2008-2013 Total	\$364,669,064	\$395,718,901

2

3

4

5

6

7

8

9

The cumulative totals of synergy savings to date show a clear distinction between the claimed Corporate Savings, the claimed Regulated Savings and the escalating amounts of Administrative & General expenses relative to KCPL's and GMO's peer utilities. The fact is that KCPL and GMO, while enjoying significant corporate retained benefits, have not flowed a comparable amount of regulated synergy savings to its regulated electric utility operations. During the three years post-acquisition, KCPL's and GMO's ratepayers continue to pay some of the highest, if not the highest A&G expenses in the region.

10

11

KCPL launched its Organizational Realignment/Voluntary Separation Program ("ORVS") on March 10, 2011. The resulting reduction of 140 KCPL employees resulted in

1 significant savings KCPL has retained and will retain through regulatory lag. This program is
2 further described by Staff Expert Charles R. Hyneman in the section of this Cost of Service
3 Report entitled “March 2010 Organizational Realignment/Voluntary Separation (ORVS)
4 Program”. Mr. Hyneman’s analysis shows that KCPL recovered all of its ORVS-related costs
5 and realized a net savings of approximately \$13 million. These employee reductions are
6 additional acquisition synergies that are being realized less than three years subsequent to the
7 acquisition of Aquila.

8 Staff Expert Arthur W. Rice has identified acquisition detriments related to
9 premature retirements subsequent to the acquisition of Aquila. These acquisition detriments are
10 further identified and explained in the Depreciation Section of this Cost of Service Report.
11 Staff Expert Arthur W. Rice has identified \$4.8 million of acquisition detriments related to the
12 Aquila acquisition.

13 **B. Qualifying Advanced Coal Project Credit for Iatan 2 Facility**

14 Because of the acquisition of Aquila by Great Plains on July 14, 2008, all former Aquila
15 employees were organized within KCPL—GMO has no employees. As such, no one represented
16 GMO with respect to the decision not to seek any of the Iatan 2 Qualifying Advanced Coal
17 Project Credit. Without a voice, GMO did not receive its proper share of these coal credits.
18 Because of the corporate structure of Great Plains after the July 2008 acquisition, GMO was not
19 afforded the opportunity to independently pursue the coal credits based on its 18% ownership of
20 Iatan 2. Another co-owner of the Iatan 2 plant facility, Empire, received through an arbitration
21 decision that it was entitled to its proportionate share of the coal credits. Had it not been for the
22 acquisition of Aquila by Great Plains, GMO (as the former Aquila) would have been in the same
23 position to pursue the coal credits as Empire and would have had the opportunity to receive the
24 benefits of such coal credits.

25 Since GMO was not able to pursue the coal credits because of the acquisition, this is a
26 merger/ acquisition detriment. Staff recommends the Commission give consideration to
27 allowing further recovery beyond the effective date of rates in this case—January 2013—because
28 of the acquisition/ merger detriment as well as the other reasons identified in this testimony.

29 For more detailed discussion of the Iatan 2 coal credits see the section of this Report
30 entitled “Qualifying Advanced Coal Project Credit for Iatan 2 Facility.”

1 **C. Recommendations**

2 Staff does not recommend the continued amortization of transition costs through KCPL's
3 cost of service. While KCPL has identified a cumulative total of \$269,495,257 of Regulated
4 Savings and \$305,991,850 of Corporate Savings, it has not complied with the Commission's
5 requirement to demonstrate that test year savings exceed the amortized transition costs per the
6 Commission Ordered Synergy Savings Tracking Model. Staff Experts Arthur W. Rice and
7 Cary G. Featherstone have identified significant acquisition detriments that were not presented to
8 the Commission when it ordered the amortization of transition costs. Through the projected
9 effective date of rates in the 2012 Rate Cases, KCPL and GMO will have received \$13.8 million
10 of amortized transition costs through the rates.

11 In the Findings of Fact section of its Order in the 2010 Rate Case in concerning this issue,
12 the Commission found the following:

13 441. In Missouri, it is well established that there is a lag between when
14 a cost or revenue is incurred and when that cost or revenue is reflected in
15 rates. This is known as regulatory lag. [footnote omitted]

16 442. As a result of regulatory lag, if a utility experiences a cost
17 decrease, there is a lag in time until that reduced cost is reflected in rates.
18 During that lag, the Company shareholders reap, in the form of increased
19 earnings, the entirety of the benefit associated with reduced costs. The
20 Company shareholders also reap, in the form of decreased earnings, the
21 entirety of the loss associated with increased costs.

22 In this case, the retained savings related to the 2011 Employee Reductions are a result of
23 regulatory lag, which the Commission recognized as a source of increased earnings as a result of
24 reduced costs without a change in its retail rates.

25 In its 2010 Rate Case Order, the Commission found that shareholders had retained
26 significant synergy savings:

27 452. As of September 1, 2009, the shareholders of KCP&L and GMO
28 had realized over \$59.3 million in synergy savings. [footnote omitted]

29 453. As of June 30, 2010, the shareholders of KCP&L and GMO had
30 realized approximately \$121 million in retained synergy savings. [footnote
31 omitted]

32 454. KCP&L and GMO project that total synergy savings through 2013
33 will be \$344 million. [footnote omitted] Of that amount, KCP&L and
34 GMO project that ratepayers will receive \$150 million. [footnote omitted]

1 The amount of savings through September 1, 2009 alone of \$59.3 million exceeded the
2 amount of deferred transition costs KCPL and GMO requested for recovery.

3 KCPL and GMO continue to realize new synergies related to the acquisition of Aquila.
4 To the extent these synergies were not included in the test year of 2009 or the true-up cutoff of
5 December 31, 2010 in the 2010 Rate Cases, those synergies are not currently being flowed to
6 ratepayers and are being retained by shareholders. These are in addition to \$121 million of
7 retained synergies the Commission identified in its 2010 Order.

8 If the Commission authorizes the continued amortization of transition costs, Staff
9 recommends that the transition costs be reduced by any retained savings related to the 2011
10 Employee Reductions in excess of severance costs (ORVS). Staff Expert Hyneman has
11 identified \$13 million of savings related to those employee reductions after the costs are
12 considered regarding the employee reductions.

13 **D. Amortization Period Relating to the Transition Costs**

14 If the Commission authorizes the continued amortization of transition costs, Staff
15 recommends a different amortization period than what the Commission determined was an
16 appropriate period in its *Order* in the 2010 Rate Case. In that *Report and Order*, the
17 Commission found the following:

18 448. KCP&L and GMO began to retain synergy savings, in the form of
19 reduced costs, immediately upon the closing of the acquisition. Given that
20 KCP&L and GMO did not have its next rate case completed until
21 September 1, 2009, the Great Plains shareholders retained the entirety of
22 these synergy savings for that period of time. [footnote omitted]

23 Staff recommended, in its Cost of Service Report in the 2010 Rate Case, that the
24 amortization of transition costs should have began at the effective date of rates of KCPL's and
25 GMO's first rate cases post-acquisition at September 1, 2009. In Finding of Fact 448 of its
26 Order in the 2010 Rate Case, the Commission recognized that KCPL and GMO began retaining
27 synergy savings immediately upon the closing of the acquisition. In consideration of this
28 finding, Staff recommends, rather than beginning the amortization of transition costs May 4,
29 2011 with respect to the 2010 case, the start of the amortization should be September 1, 2009
30 which is the effective date of the 2009 rate case (ER-2009-0089) KCPL and GMO were

1 authorized to amortize transition costs pursuant to the Commission's *Report and Order*. As a
2 result, an amount of transition costs exists in the test year cost of service.

3 Staff Adjustments E-197.2 and E-205.4 removes the test year amortization of transition
4 costs from the cost of service.

5 *Staff Expert/Witness: Keith Majors*

6 **XVII. Appendices**

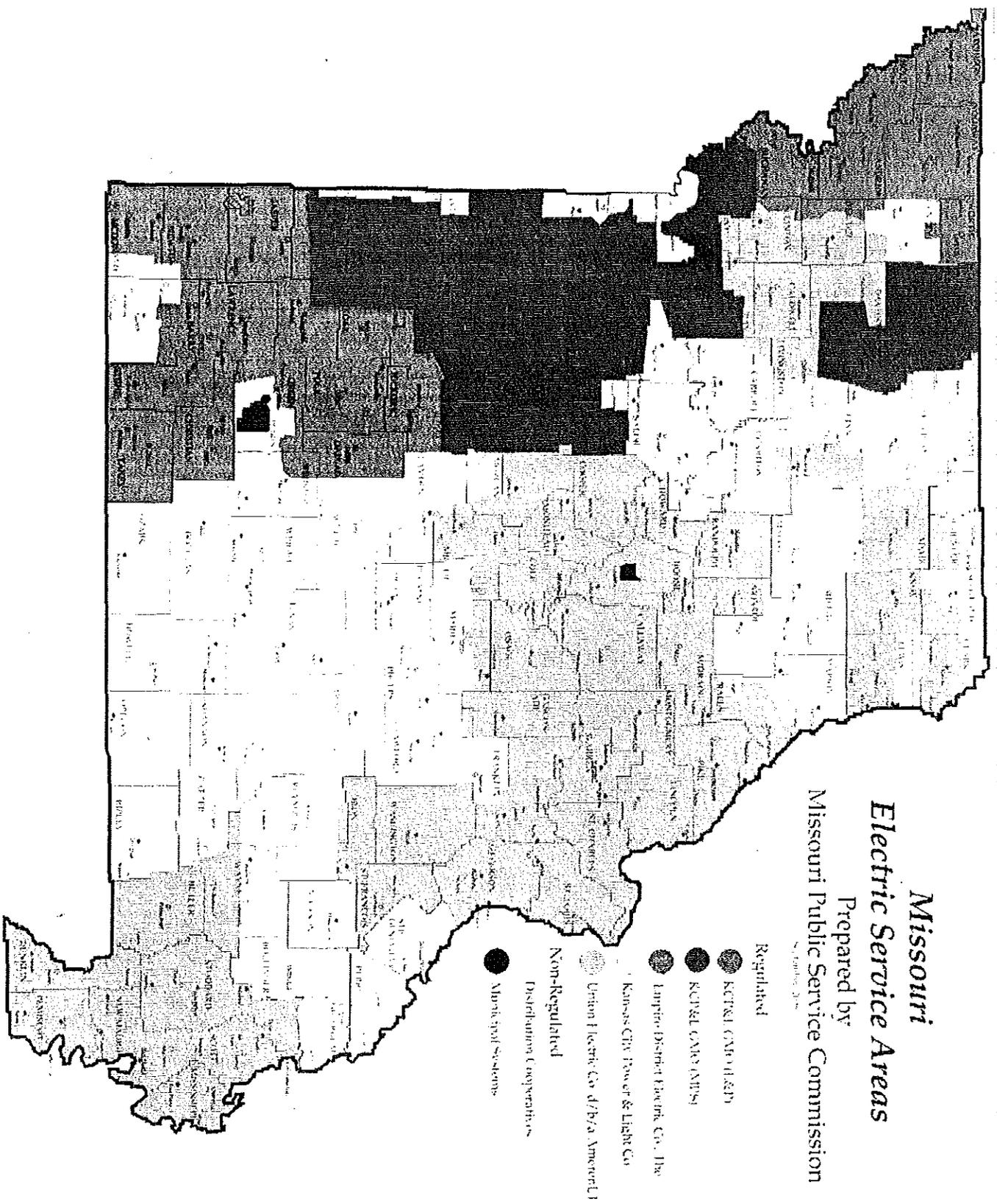
7 Appendix 1 - Staff Credentials

8 Appendix 2 - Support for Staff Cost of Capital Recommendation
9 -David Murray

10 Appendix 3 -- Other Staff Schedules

Missouri Electric Service Areas

Prepared by
Missouri Public Service Commission



BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light)
Company's Request for Authority to) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF ALAN J. BAX

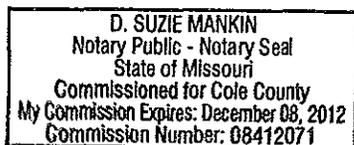
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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 August, 2012.





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) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF DANIEL I. BECK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

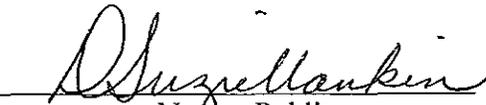
Daniel I. Beck, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.



Daniel I Beck

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071



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) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF CARY G FEATHERSTONE

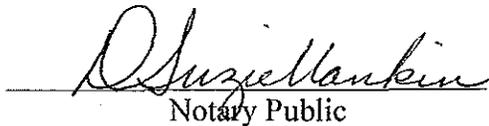
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071


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) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

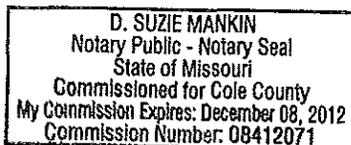
AFFIDAVIT OF PATRICIA GASKINS

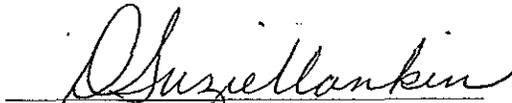
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Patricia Gaskins, 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.


Patricia Gaskins

Subscribed and sworn to before me this 2nd day of August, 2012.




Notary Public

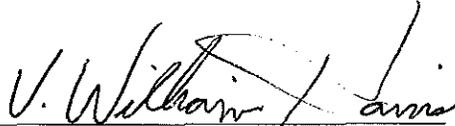
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light)
Company's Request for Authority to) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

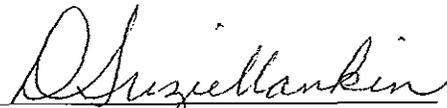
V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.



V. William Harris

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071



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) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF CHARLES R. HYNEMAN

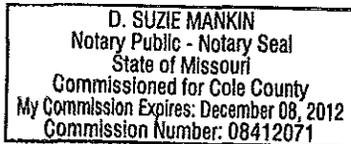
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

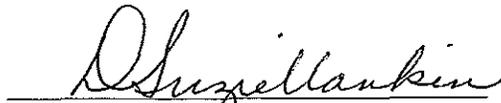
Charles R. Hyneman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.



Charles R. Hyneman

Subscribed and sworn to before me this 2nd day of August, 2012.





Notary Public

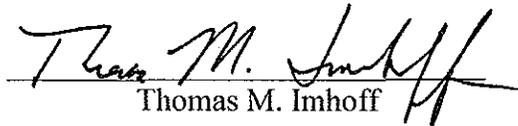
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light)
Company's Request for Authority to) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF THOMAS M. IMHOFF

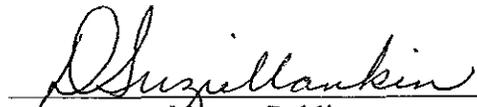
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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.


Thomas M. Imhoff

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071


Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

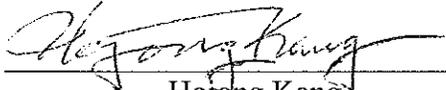
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light)
Company's Request for Authority to) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF HOJONG KANG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

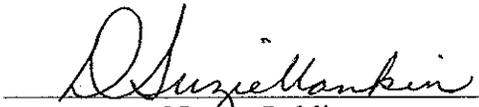
Hojong Kang, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.



Hojong Kang

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071



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) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

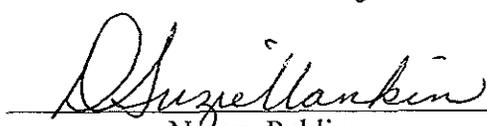
Robin Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.



Robin Kliethermes

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071



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-2012-0174

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

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071


Notary Public

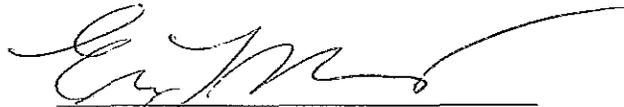
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light)
Company's Request for Authority to) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF ERIN L. MALONEY

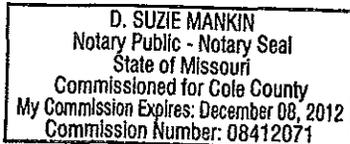
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

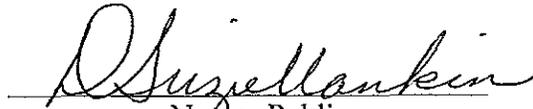
Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.



Erin L. Maloney

Subscribed and sworn to before me this 2nd day of August, 2012.





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) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

AFFIDAVIT OF CONTESSA POOLE-KING

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

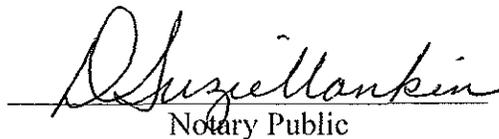
Contessa Poole-King, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.



Contessa Poole-King

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071



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-2012-0174

AFFIDAVIT OF BRET G. PRENGER

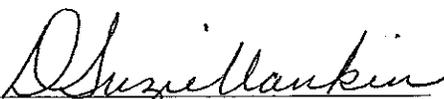
STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Bret G. Prenger, 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.


Bret G. Prenger

Subscribed and sworn to before me this 2nd day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071


Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

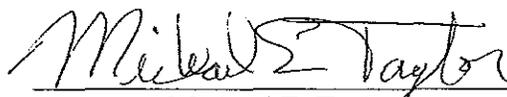
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light)
Company's Request for Authority to) Case No. ER-2012-0174
Implement A General Rate Increase for)
Electric Service)

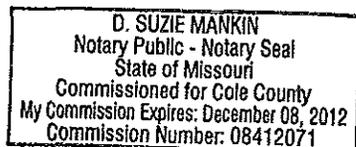
AFFIDAVIT OF MICHAEL E. TAYLOR

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael E. Taylor, 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 E. Taylor

Subscribed and sworn to before me this 2nd day of August, 2012.




Notary Public

