

**MISSOURI PUBLIC SERVICE COMMISSION**

**STAFF REPORT**  
**REVENUE REQUIREMENT**



**THE EMPIRE DISTRICT ELECTRIC COMPANY**

**CASE NO. ER-2016-0023**

*Jefferson City, Missouri*  
*March 25, 2016*

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

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**TABLE OF CONTENTS OF  
STAFF REPORT  
REVENUE REQUIREMENT  
THE EMPIRE DISTRICT ELECTRIC COMPANY  
CASE NO. ER-2016-0023**

6	I. Executive Summary .....	1
7	A. Major Issues .....	2
8	B. Public Comments .....	3
9	C. Regulatory Trackers .....	3
10	II. Background of EDE .....	4
11	III. Test Year/Update Period/True-Up .....	5
12	IV. Riverton Conversion Project (Construction Audit) .....	6
13	A. Description of Project .....	6
14	B. In-Service Criteria for Riverton 12 CC Unit .....	7
15	C. Construction Audit of the Riverton 12 CC Unit .....	7
16	D. Decision to Build Riverton 12 CC Unit .....	9
17	V. Asbury Air Quality Control System (“AQCS”) .....	10
18	A. Purpose of Staff’s Construction Audit and Prudence Review .....	10
19	B. Risk Assessment .....	11
20	C. Audit Scope .....	11
21	D. Fully Operational and Useful for Service .....	12
22	E. Decision to Construct the AQCS .....	12
23	F. Bidding Process .....	12
24	G. Gross Capital Cost and Expenses of the Project and Recommended Cost .....	13
25	H. Staff Recommendation .....	15
26	VI. Economic Considerations .....	15
27	VII. Rate of Return .....	20
28	A. Introduction .....	20
29	B. Analytical Parameters .....	22
30	C. Current Economic and Capital Market Conditions .....	26
31	1. Economic Conditions .....	26
32	2. Capital Market Conditions .....	28
33	a. Utility Debt Markets .....	28
34	b. Utility Equity Markets .....	30
35	D. Empire’s Operations .....	34
36	E. Empire’s Credit Ratings .....	35
37	F. Algonquin’s Proposed Acquisition of Empire .....	36
38	G. Cost of Capital .....	37
39	1. Capital Structure .....	37
40	2. Embedded Cost of Debt .....	38
41	3. Cost of Common Equity .....	38

1	a. The Proxy Group .....	38
2	b. The Constant-growth DCF .....	39
3	c. The Multi-stage DCF .....	42
4	H. Tests of Reasonableness .....	51
5	1. The CAPM .....	51
6	2. Other Tests .....	53
7	a. The “Rule of Thumb” .....	53
8	b. Average Authorized Returns .....	54
9	I. Conclusion .....	55
10	VIII. Rate Base .....	56
11	A. Plant in Service .....	56
12	1. Plant in Service updated as of September 30, 2015 .....	56
13	2. Plant Adjustments: Allocation to Gas .....	56
14	B. Depreciation Reserve .....	57
15	1. Depreciation Reserve as of September 30, 2015 .....	57
16	2. Reserve Adjustments: Allocation to Gas .....	57
17	3. Plant & Depreciation Reserve Adjustments: Capitalized Incentive Compensation .....	57
18	C. Cash Working Capital (“CWC”) .....	58
19	D. Prepayments and Materials and Supplies .....	58
20	E. Fuel Inventories .....	59
21	F. Amortization of Electric Plant .....	60
22	G. Amortization of PeopleSoft Intangible Asset .....	60
23	H. Customer Deposits .....	60
24	I. Customer Advances .....	61
25	J. Accumulated Deferred Income Taxes (“ADIT”) .....	61
26	K. Vegetation Management Tracker Regulatory Asset .....	62
27	L. Iatan and Plum Point Carrying Costs .....	63
28	1. Iatan 1 .....	63
29	2. Iatan 2 .....	63
30	3. Plum Point .....	64
31	4. Iatan Carrying Costs Amortization .....	64
32	5. Southwestern Power Administration (“SWPA”) Hydro Reimbursement .....	65
33	IX. Allocations .....	65
34	A. Corporate Allocations .....	65
35	B. Jurisdictional Allocation Factors .....	67
36	1. Demand Allocation Factor .....	67
37	2. Energy Allocation Factor .....	68
38	X. Income Statement .....	69
39	A. Rate Revenues .....	69
40	1. Introduction .....	69
41	2. Definitions .....	69
42	3. The Development of Rate Revenue in this Case .....	70
43	4. Regulatory Adjustments to Update Period Usage and Rate Revenue .....	70

1	a. Update Period Adjustment .....	70
2	b. Weather Variables .....	71
3	c. Weather Normalization .....	73
4	d. 365-Days Adjustment .....	74
5	e. Normalization and Annualization of Billing Determinants.....	75
6	f. Missouri and Non-Missouri Large Power (“LP”) and Feed Mill &	
7	Grain Elevator Service (“PFM”) Annualizations.....	76
8	g. Adjustments for Non-Missouri classes.....	76
9	h. Rate Switching.....	77
10	i. Customer Growth (Annualization).....	77
11	j. Annualization of Excess Facility Charge Revenues.....	78
12	k. Praxair and Special Contract Revenue Imputation.....	78
13	5. Other Revenues .....	79
14	a. FAC Revenues.....	79
15	b. Unbilled Revenues.....	79
16	c. Gross Receipts Revenues .....	79
17	d. SO2 Allowances .....	79
18	e. Renewable Energy Credits (“REC”) .....	80
19	f. Water Revenues.....	80
20	g. Coal Fly Ash Revenues .....	81
21	h. Miscellaneous Revenues .....	81
22	B. Southwest Power Pool (“SPP”) Revenues and Expenses .....	81
23	1. SPP Transmission Revenues .....	81
24	2. SPP Transmission Expenses.....	82
25	3. Ancillary Services Market Revenue and Expense .....	82
26	4. Miscellaneous SPP Related Revenues and Expenses .....	83
27	5. Off-system sales revenue and expense.....	83
28	C. Fuel and Purchased Power .....	83
29	1. Fixed Costs .....	83
30	a. Fuel Adders .....	83
31	b. Purchased Power – Capacity Charges .....	84
32	c. Fuel Prices .....	84
33	2. Losses .....	86
34	3. Variable Costs .....	87
35	4. Planned and Forced Outages .....	88
36	5. Energy Sales and Purchases .....	88
37	6. Capacity Contract Prices and Energy .....	89
38	7. Normalized Net System Input (“NSI”) .....	89
39	8. Purchased Power Prices .....	90
40	9. Entergy Transmission Contract.....	91
41	D. DEPRECIATION.....	91
42	1. Depreciation Rates .....	91
43	2. Stopped Depreciation Accrual/Set Depreciation Rate to 0 Percent .....	92
44	3. “Shortfall / Deficiency” for the Retirement of Riverton Units 7 and 8.....	95

1	4. Riverton 12 CC Estimated Depreciation Expense .....	96
2	5. Recommendations .....	96
3	E. RIVERTON 12 O&M TRACKER .....	97
4	F. Payroll and Benefits .....	98
5	1. Payroll, Payroll Taxes and 401(k).....	98
6	2. Incentive Compensation .....	99
7	a. Management Incentive Compensation Plan (“MIP”).....	99
8	b. Lightning Bolts.....	100
9	c. Equity Incentive Compensation .....	100
10	3. Payroll Benefits .....	101
11	4. FAS 87 and FAS 88 Pension Costs .....	101
12	5. FAS 106 – Other Post-Employment Benefit Costs (“OPEBs”).....	102
13	6. Supplemental Executive Retirement Plan (“SERP”) .....	103
14	G. Maintenance Normalization Adjustments .....	104
15	1. Iatan 1 .....	104
16	2. Asbury .....	104
17	3. Riverton (Excluding Riverton Unit 12).....	105
18	4. State Line Combined Cycle (“SLCC”) and State Line Common .....	105
19	5. State Line 1.....	105
20	6. Energy Center and Ozark Beach .....	105
21	H. O&M Expenses for Iatan 2, Iatan Common, and Plum Point .....	106
22	I. Other Non-Labor Expenses .....	106
23	1. Customer Deposit Interest Expense .....	106
24	2. Property Tax Expense .....	106
25	3. Corporate Franchise Taxes.....	108
26	4. Amortization Expenses .....	108
27	a. Amortization of Electric Plant.....	108
28	b. Amortization of Stock Issuance Costs.....	108
29	c. Amortization of Ice Storm Costs.....	108
30	5. Iatan Carrying Costs Amortization .....	109
31	6. Demand Side Management .....	109
32	a. DSM Programs .....	109
33	b. DSM Cost Recovery.....	111
34	c. Chapter 22 Electric Utility Resource Planning .....	111
35	d. MEEIA Filings .....	111
36	7. Low Income Programs .....	112
37	a. Low Income Weatherization .....	112
38	8. Current and Deferred Income Tax .....	114
39	a. Current Income Taxes .....	114
40	b. Deferred Income Taxes .....	115
41	9. Insurance Expense.....	117
42	10. Bad Debt Expense .....	117
43	11. Postage .....	117

1	12. PSC Assessment and Rate Case Expense .....	118
2	a. PSC Assessment .....	118
3	b. Rate Case Expense .....	118
4	13. Injuries and Damages and Workers' Compensation .....	121
5	14. Advertising Expense .....	121
6	15. Outside Services .....	122
7	16. Dues and Donations .....	122
8	17. Edison Electric Institute ("EEI") Dues.....	123
9	18. Tree Trimming Expense/Infrastructure Inspection Expense.....	124
10	19. SWPA Amortization .....	125
11	20. Lease Expense .....	125
12	21. Solar Rebates.....	126
13	22. Tornado AAO Amortization .....	126
14	23. Software Maintenance Expense .....	127
15	24. Corporate Expenses.....	127
16	25. Capitalized Depreciation .....	128
17	XI. Fuel Adjustment Clause ("FAC").....	128
18	A. Policy.....	128
19	B. History .....	129
20	C. Continuation of FAC.....	131
21	D. Southwest Power Pool Integrated Market.....	133
22	E. Revising the Base Factor.....	134
23	F. Additional Reporting Requirements.....	136
24	G. FAC Voltage Adjustment Factors .....	137
25	H. Loss Study – Compliance with FAC Rules.....	138
26	I. Heat Rate Testing Review .....	138
27	XII. Miscellaneous .....	139
28	A. Proposed Acquisition .....	139
29	B. Renewable Energy Standard ("RES") Summary .....	140
30	Appendices:.....	141
31		



1                   **Impact of Staff’s Revenue Requirement on Each Retail Rate Customer Class**

2                   The impact of Staff’s recommended rate change for each retail rate customer class will be  
3 proposed in Staff’s class cost of service report and rate design testimony that is to be filed on  
4 April 8, 2016.

5                   **A. Major Issues**

6                   The following are the major differences in traditional revenue requirement that exist  
7 between Staff and Empire based on their respective direct filings. A brief explanation of each  
8 item follows:

9                   **Return on Equity (“ROE”)** – Staff has recommended a 9.5% to 10.0% reasonable range  
10 for ROE for Empire. This issued is addressed in detail in the Section VII of this Report.

11                   **Depreciation** - Staff conducted a depreciation study of EDE’s current authorized  
12 depreciation rates. In Staff’s review of the depreciation study filed by Empire in this proceeding,  
13 Staff found depreciation rate recommendations of zero percent for five accounts on a going-  
14 forward basis. Staff recommends the Commission approve the depreciation dates proposed in  
15 Appendix 3, Schedule JAR(DEP)-d1 and order EDE to discontinue its practice of changing its  
16 rates to zero percent whenever the depreciation reserve equals the related plant in service  
17 balance. Staff proposes adjustments to the depreciation reserve in the amount of \$3,082,367  
18 to remove the effects of EDE changing its rates to zero percent from any rates established in  
19 this case.

20                   With the retirement of Riverton Units 7 and 8, the accumulated depreciation reserves  
21 are under recovered by \$7.8 million. Depreciation Staff is not recommending an amortization of  
22 the unrecovered reserve as requested by Empire. Depreciation Staff is recommending to transfer  
23 reserves.

24                   **Riverton Combined Cycle Conversion** – Empire is in the process of converting its  
25 Riverton 12 combustion turbine to a combined cycle unit. The construction of this conversion is  
26 scheduled to be completed by June 1, 2016. Empire has included projected construction costs  
27 and expenses in its cost of service. Staff has included an estimate of these costs in its cost of  
28 service. If the conversion meets its in-service criteria by June 1, 2016, Staff will include all  
29 construction costs prudently incurred as of March 31, 2016, in its true-up audit cost of service.



1           **Fuel and Purchased Power** – Staff has calculated Empire’s Fuel and Purchased Power  
2 using its fuel model dispatch to calculate Empire’s fuel and purchased power prior to the  
3 conversion of the Riverton 12 unit from a combustion turbine to a combined cycle plant. The  
4 Riverton Combined Cycle Plant is currently being constructed and is not operational. Staff will  
5 update its Fuel and Purchased Power costs during the true-up audit for this case to reflect  
6 Empire’s level of expense assuming operation of Riverton 12 as a combined cycle plant if the  
7 unit is operational at that time.

8           **Income Taxes - \*\*** \_\_\_\_\_

9 \_\_\_\_\_ \*\* Thus Staff has made an adjustment to zero out current  
10 income tax expense and transfer the amount to deferred income tax expense.

11           There are various other issues between Staff and Empire based on their respective direct  
12 filings which appear to be of lower dollar magnitude. These issues are discussed in this Report  
13 as well.

14           **B. Public Comments**

15           At the time of the filing of Staff’s direct testimony, the Commission had received  
16 30 public comments regarding the subject matter of this rate case. Since two of these public  
17 comments are duplicates, there are 29 individual comments received at this time. Additional  
18 comments are still being received. Schedule KKB-d1 shows the comments that have been  
19 received to date. It is expected that the April local public hearings and the later stages of the case  
20 will continue to generate additional comments.

21           **C. Regulatory Trackers**

22           The following are tracking mechanisms which the Staff considered in this cost of service  
23 study. While continuation of current trackers may not have an immediate direct effect on the  
24 EDE’s revenue requirement, their ongoing operation will impact future rate cases and future  
25 revenue requirements. The Vegetation Management Tracker and the Iatan and Plum Point  
26 Operations and Maintenance (“O&M”) Tracker were discontinued with the resolution of the  
27 previous case, Case No. ER-2014-0351. Staff has calculated the accumulated amounts for these  
28 trackers as of the effective date of rates in the last case and is amortizing the balances. While  
29 there are now fewer trackers in place for Empire, Staff’s position remains that use of trackers can

1 be appropriate under certain circumstances. Staff recommends the use of the following trackers  
2 by Empire on an ongoing basis:

3 **Riverton 12 Unit Maintenance Tracker** – A tracker was established in the last rate  
4 case, Case No. ER-2014-0351, for costs associated with the new maintenance contract with  
5 Siemens Instrumentation, Controls and Electrical Group (“Siemens”) for the Riverton 12 unit.  
6 The tracker base amount of \$2.7 million Missouri Jurisdictional was agreed to in the  
7 *Non-Unanimous Stipulation and Agreement*. In this current case, Empire is proposing to rebase  
8 the Riverton 12 O&M tracker from \$2.7 million to \$3.9 million based on a new estimated  
9 equivalent operating hours (“EOH”) calculation. It is Staff’s position that the tracker base level  
10 remain at \$2.7 million as there has not yet been sufficient operational history for this unit in  
11 combined cycle operation to determine a more accurate estimate.

12 **Pension and OPEBs Tracker** – Staff recommends continuation of the pension  
13 and OPEBs trackers that were last authorized for continuance in Empire’s previous rate case,  
14 Case No. ER- 2014-0351.

15  
16 *Staff Expert/Witness Kimberly K. Bolin*

## 17 **II. Background of EDE**

18 EDE is a Kansas corporation providing retail electrical utility services in Missouri,  
19 Kansas, Arkansas, and Oklahoma. As of September 30, 2015, Empire served approximately  
20 169,142 retail electric customers throughout its system of which approximately 150,397 are  
21 Missouri customers. EDE provides wholesale electrical service to three municipalities in  
22 Missouri and one municipality in Kansas. EDE also provides water utility services in Missouri.  
23 EDE is a service company and a holding company. EDE owns and services Empire District Gas  
24 Company (“EDG”), an affiliated Missouri natural gas distribution business. EDE also owns and  
25 services The Empire District Industries, Inc. (“EDI”) an affiliated Missouri non- regulated fiber  
26 optic business.

27 Empire last sought to change its Missouri jurisdictional electric retail rates in Case No.  
28 ER-2014-0351. Through its *Order* dated June 24, 2015, in that proceeding, the Commission  
29 granted Empire a total net increase in rates of \$17,150,000.

1 On March 16, 2016, Empire filed with the Commission an application along with Liberty  
2 Utilities (Central) Co. (“LU Central”) and Liberty Sub Corp. authorizing LU Central and Liberty  
3 Sub Corp. to acquire all of the common stock of Empire. The case, Case No. EM-2016-0213 is  
4 currently pending before the Commission. The outcome of the merger case is not expected to be  
5 finalized during the pendency of this case.

6  
7 *Staff Expert/Witness Kimberly K. Bolin*

### 8 **III. Test Year/Update Period/True-Up**

9 The purpose of an update period is to establish a cut-off point as to which major elements  
10 of a utility’s revenue requirement are to be updated, beyond the test year, for inclusion in Staff’s  
11 and other parties’ direct cases. In contrast, a true-up is a re-audit and update of major elements  
12 of a utility’s revenue requirement beyond the end of the ordered test year and update period.  
13 When ordered, true-ups involve the filing of additional testimony and the scheduling of  
14 additional evidentiary hearings by the Commission.

15 Empire filed its case based upon final costs and billing determinants used to establish  
16 current rates in its last rate case, Case No. ER-2014-0351. In that case, the Commission ordered  
17 a test year based upon twelve months ending April 30, 2014, with an update period to  
18 reflect known and measureable changes through August 31, 2014. The parties have agreed to  
19 use the final rate base levels, revenues and expenses (i.e. revenue requirement components), as  
20 well as the billing determinants used in Case No. ER-2014-0351, as a starting point for the  
21 analysis of Empire’s need for a rate change in this case. The billing determinants and other  
22 revenue requirement components will be analyzed and updated through September 30, 2015.

23 The parties have agreed to a true-up of significant items through March 31, 2016, with a  
24 Riverton 12 conversion in-service no later than June 1, 2016. Staff has included in Staff’s  
25 Accounting Schedules an estimate of the impact the addition of this plant will cause on Empire’s  
26 revenue requirement. Due to the fact that the Riverton 12 conversion is expected not to be in-  
27 service as of the end of the true-up period in this case, Staff considers the inclusion of  
28 Riverton 12 conversion project costs in rates in this proceeding to be an “out of period  
29 adjustment.” Therefore, Staff recommends that an “average declining balance” approach be used  
30 to calculate the revenue requirement impact of Riverton 12 on rates during the first year it will be

1 in service. To calculate the average declining balance, Staff used the estimated book value as of  
2 March 31, 2016, to calculate the associated monthly depreciation expense. Then, the  
3 depreciation expense was deducted from the estimated book value per month to derive a monthly  
4 depreciated balance for 12 months. Finally, Staff averaged the balance for those twelve months.  
5 Staff considers the Riverton 12 project costs to be an out of period adjustment in this proceeding  
6 because no costs are eligible to be included in rates unless the project goes in service by June 1,  
7 2016, which is outside the test year, update and true-up periods in this case. There is no actual  
8 plant in service balance in existence related to this project as of the March 31, 2016, true-up cut-  
9 off date in this case. While Staff is not opposed to inclusion of Riverton 12 costs in rates  
10 resulting from this case as an out of period adjustment if the project qualifies for in-service status  
11 as of June 1, 2016, Staff's position is that the rate base valuation treatment described above is  
12 appropriate given its out of period status. The "Allowance for True-up" estimated value  
13 provided on Accounting Schedule 1, Revenue Requirement, is based in part on valuation of the  
14 Riverton 12 project costs on an average declining cost basis.

15 For purposes of the true-up audit, Staff will update the following items through  
16 March 31, 2016: plant in service; depreciation reserve, other rate base components (including  
17 trackers); payroll expense; payroll-related benefits; fuel and purchased power costs; depreciation  
18 and amortization expense; rate case expense; property taxes; related income tax effects; the  
19 customer growth annualization for revenues, SPP transmission revenues and expenses, other  
20 SPP revenues and expenses, capital structure, and debt costs used in determining the rate  
21 of return. This is not an all-inclusive list of items to be updated. Other items might be added to  
22 the list to be updated as data becomes available that indicates that their consideration is needed to  
23 develop an appropriate matched cost of service analysis.

24 *Staff Expert/Witness: Amanda C. McMellen*  
25

## 26 **IV. Riverton Conversion Project (Construction Audit)**

### 27 **A. Description of Project**

28 Prior to conversion, Riverton Unit 12 was a simple cycle natural gas-fired combustion  
29 turbine fully owned by Empire located at the 107-year old Riverton Power Plant in Riverton,  
30 Kansas (about thirty minutes west of Joplin, Missouri). When this unit was originally constructed

1 natural gas piping, electrical transmission and the plant layout were designed and built to  
2 accommodate its conversion to a combined cycle unit at some point in the future.  
3 This construction project incorporates the Riverton Unit 12 combustion turbine as part of a  
4 combined cycle unit. "Combined Cycle" refers to the fact that the system uses waste heat  
5 from the combustion power cycle to produce steam that is used as the motive force in a  
6 steam power cycle. The project requires the addition of a heat recovery steam generator  
7 ("HRSG"), a steam turbine generator ("STG"), auxiliary boiler, cooling towers to provide  
8 cooling water for the condenser, new control room and control system and other auxiliary plant  
9 equipment. The Riverton 12 simple cycle to combined cycle conversion project will add about  
10 \*\* \_\_\_\_\_ \*\*, making the Riverton combined cycle a \*\* \_\_\_\_ \*\* MW unit upon  
11 completion.

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

14 **B. In-Service Criteria for Riverton 12 CC Unit**

15 The Staff and Empire have agreed on a set of in-service criteria to be used to verify when  
16 the Riverton 12 combined cycle ("CC") generating unit is fully operational and used for service  
17 and should be considered for inclusion in rate base. These in-service criteria are attached as  
18 Schedule ELM-d1 to this report. Staff will review all test records, operating logs, computer data  
19 and other documentation provided by the Company to determine if the generating unit  
20 successfully meets all of the in-service criteria and is fully operational and used for service when  
21 the latest project status and start-up and commissioning reports are made available. Staff will  
22 make a recommendation in its final construction audit report prior to the end of the true-up  
23 period for this case.

24  
25 *Staff Expert/Witness: Erin L. Maloney*

26 **C. Construction Audit of the Riverton 12 CC Unit**

27 As of September 30, 2015, the end of the update period for this case, the Company was in  
28 the process of completing the construction of the Riverton Conversion Project / Construction.  
29 The parties have agreed to true-up certain significant items of this case through March 31, 2016,

1 if the Company meets the Riverton 12 conversion in-service criteria by no later than June 1,  
2 2016. Based upon the expected completion date of this project, Staff is continuing to conduct a  
3 construction audit of the new plant and will provide the results of that audit during the true-up  
4 phase of this rate case proceeding.

5 Staff's construction audit and prudence review will include a determination of the  
6 appropriate level of construction costs related to the Riverton conversion project for the purpose  
7 of setting rates, and provide an independent and objective assessment of the utility's performance  
8 as it relates to these specific construction project activities. As part of its construction audit and  
9 prudence review, Staff is examining Empire's: (1) entry into agreements to pursue the Riverton  
10 Conversion project, (2) Request for Proposals for contractors, (3) Bid Proposals (4) actual  
11 expenditures as compared to estimates, and (4) whether the Company's decisions or costs  
12 associated with those decisions were (a) inappropriate, (b) unreasonable, (c) excessive, (d)  
13 unreasonably or inappropriately allocated, (e) not of benefit to Missouri ratepayers or (f) related  
14 to unnecessary facilities. Staff reviewed the Company's decisions considering whether such  
15 decisions would result in harm to Empire's ratepayers, in light of the following factors  
16 established by Staff:

- 17 1. Impact on rate base with related impact on interest cost, expected profit,  
18 income taxes;
- 19 2. Projected operation and maintenance expense;
- 20 3. Projected fuel and consumable-related expense;
- 21 4. Projected effect on fuel and purchased-power cost recovery mechanisms;
- 22 5. Projected effect on depreciation rates and expense;
- 23 6. Projected operational impacts, including plan dispatch ability, dispatch  
24 order, or reductions to net generation;
- 25 7. Consistency with the utility's Preferred Resource Plan effective at the time  
26 the project was undertaken, and as subsequently updated or superseded;
- 27 8. Compliance with State and Federal environmental and renewable energy  
28 standards and any other applicable State and Federal mandates in effect  
29 during the construction of the project;
- 30 9. Compliance with settlements or other agreements; and
- 31 10. Evaluation of other projects to improve this project.

32 The Company commissioned a study related to the Clean Water Act, Section 316(b) regulation  
33 and Staff is currently evaluating Empire's decision to fully allocate the cost of that study to the

1 capital cost of this project. Staff's final report will provide an independent assessment of  
2 Empire's stewardship, performance, and costs as it relates to construction project activities.  
3 Staff's final report will also contain analysis regarding the impact of the combined cycle unit on  
4 operational and maintenance expense, fuel and consumable-related expense, and the effect on the  
5 Company's fuel adjustment clause. Staff continues to review engineering and cost data and will  
6 submit a completed audit report when the project is complete.

7  
8 *Staff Expert/Witness: Kimberly K. Bolin, Paul Harrison and Erin L. Maloney*

9 **D. Decision to Build Riverton 12 CC Unit**

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

10 **V. Asbury Air Quality Control System (“AQCS”)**

11 **A. Purpose of Staff’s Construction Audit and Prudence Review**

12 In Empire’s previous case, Case No. ER-2014-0351, the parties agreed in the *Stipulation*  
13 *and Agreement* to adopt Staff’s recommended in-service criteria and found that the Asbury  
14 AQCS was fully operational and used for service. However, Staff’s construction audit was not  
15 complete at that time so the parties agreed that any party to Empire’s next rate case (*i.e.*, this  
16 case) could argue the book value of the Asbury AQCS. Staff has since completed this audit to  
17 determine the appropriate level of construction costs, related to Asbury’s AQCS constructed as  
18 the Asbury Environmental Retrofit Project (“AERP”), to be used for purposes of setting rates,  
19 and to provide an independent and objective assessment of the utility’s performance as it relates  
20 to these specific construction project activities. As part of its construction audit and prudence  
21 review, Staff examined Empire’s (1) entry into agreements to pursue the AERP, (2) undertaking  
22 of the AERP and (3) continuing with construction of the AERP in light of whether the decisions  
23 or costs associated with those decisions were (a) inappropriate, (b) unreasonable, (c) excessive,  
24 (d) unreasonably or inappropriately allocated, (e) not of benefit to Missouri ratepayers or  
25 (f) related to unnecessary facilities. Staff reviewed the company’s decisions considering whether  
26 such decisions would result in harm to Empire’s ratepayers, in light of the following factors  
27 established by Staff:

\_\_\_\_\_ <sup>5</sup> \*\* \_\_\_\_\_ \*\*





- 1 1. Impact on rate base;
- 2 2. Projected operation and maintenance expense;
- 3 3. Projected fuel and consumable-related expense;
- 4 4. Projected effect on the Fuel and Purchased-Power Cost Recovery
- 5 Mechanisms;
- 6 5. Projected effect on depreciation rates and expense;
- 7 6. Projected operational impacts, including plan dispatch ability, dispatch order,
- 8 or reductions to net generation;
- 9 7. Consistency with the utility's Preferred Resource Plan effective at the time the
- 10 project was undertaken, and as subsequently updated or superseded;
- 11 8. Compliance with State and Federal environmental and renewable energy
- 12 standards and any other applicable State and Federal mandates in effect during
- 13 the construction of the project;
- 14 9. Compliance with settlements or other agreements; and
- 15 10. Evaluation of other projects to improve this project.

## 16 **B. Risk Assessment**

17 The Staff has determined that the Asbury AQCS costs incurred were prudent, reasonable,  
18 appropriate, and constitute a benefit to Missouri ratepayers. The Staff's basis for this  
19 determination is a thorough examination of all actual costs.

## 20 **C. Audit Scope**

21 As part of its audit scope, Staff reviewed the costs and schedule controls utilized by  
22 Empire and its project managers in order to familiarize itself with the policies and procedures  
23 Empire had in place to control costs and mitigate risks for the Asbury AQCS project.  
24 Staff reviewed the following documents during the audit process:

- 25 1. Asbury Environmental Retrofit Project monthly reports
- 26 2. Key vendor contracts
- 27 3. Empire District Electric Board of Director Minutes
- 28 4. Work Orders
- 29 5. Invoices
- 30 6. Change Order Requests
- 31 7. Requests for Proposal Letters
- 32 8. Internal Procedures and Policies for Empire
- 33 9. Alberici Stanley Joint Venture weekly meeting minutes

1 Staff also visited the construction site and asked questions of Empire personnel during the  
2 site visit.

3 **D. Fully Operational and Useful for Service**

4 During Empire’s last rate case, Case No. ER-2014-0351, Staff determined that the AQCS  
5 improvements at the Asbury plant were completed and the plant met its in-service criteria as of  
6 December 2014. AQCS improvements consist of a scrubber, fabric filter, and power activated  
7 carbon injection system as part of Empire’s plan to comply with Environmental Protection  
8 Agency (“EPA”) standards.

9 **E. Decision to Construct the AQCS**

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22 **F. Bidding Process**

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**G. Gross Capital Cost and Expenses of the Project and Recommended Cost**

When Empire first decided to install the AQCS at Asbury, it began with a budget of

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Empire had five change orders to the original project budget. The following table provides the reason for each of the change orders and the amount of each change order.

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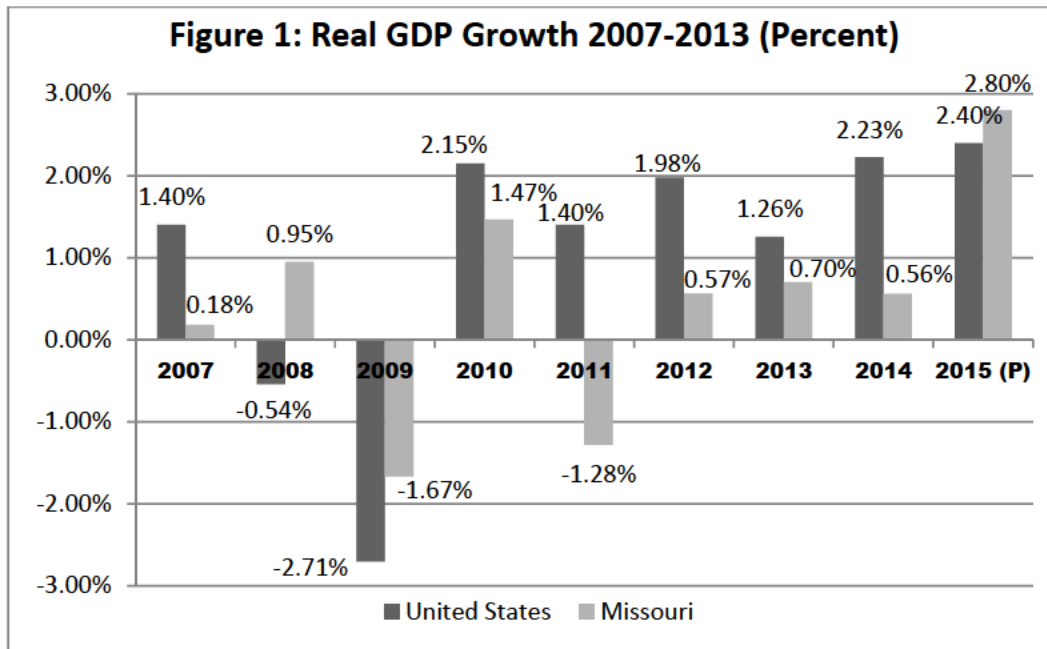
1           **H. Staff Recommendation**

2           Staff is not proposing any adjustments to actual Asbury AQCS Project costs.

3  
4           *Staff Expert/Witness: Kimberly K. Bolin*

5           **VI. Economic Considerations**

6           Preliminary 2015 data indicates that Missouri’s general economic condition, specifically  
7           the counties<sup>6</sup> that compose the service area of Empire, may have finally recovered from the  
8           recession of December 2007 to June 2009. Figure 1, below, shows that the real gross domestic  
9           product (“GDP”) growth of Missouri had been averaging less than one percent (1%) per year  
10          since the recession ended, but the preliminary 2015 data shows a robust year-over-year growth  
11          rate at 2.80 percent—the largest annual growth rate since 2000.



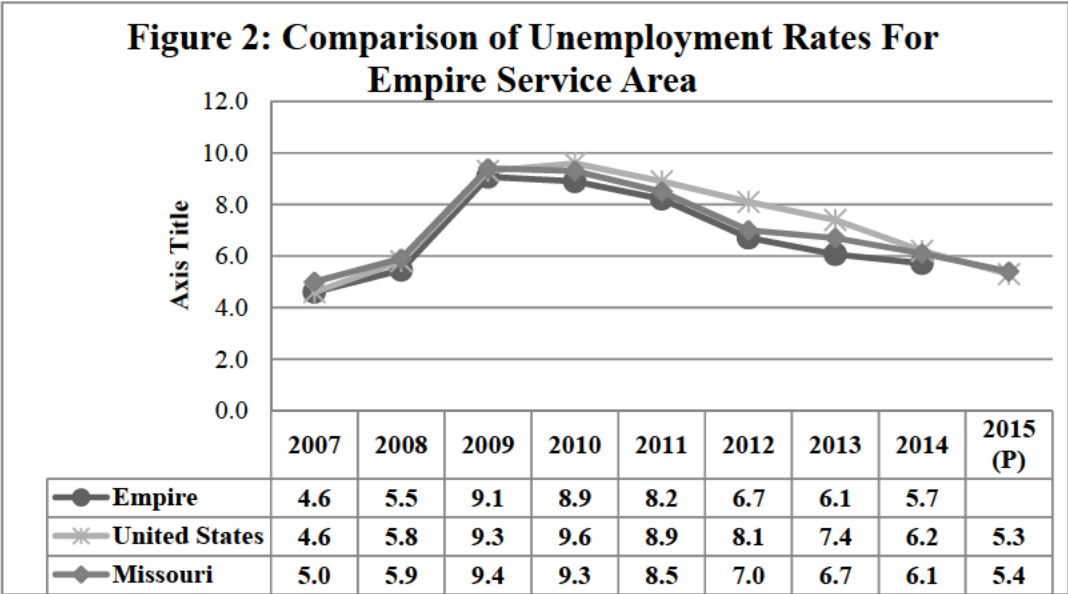
13           As seen in Figure 2, below, the annual unemployment levels are approaching the  
14           pre-recession levels. The preliminary unemployment rate estimates for 2015 show the Missouri  
15           unemployment rate below the 2008 unemployment rate. Preliminary unemployment rate data for  
16           Empire’s service territory is unavailable. However, since the combined unemployment rate for

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<sup>6</sup> According to Schedule 2 of the minimum filing requirements and the current tariffs, Empire serves a total of 16 counties.

1 all of the counties that Empire serves tends to be 0.3 to 0.4 percent less than Missouri's  
 2 unemployment rate, it is reasonable to anticipate a 5.0 to 5.1 percent unemployment rate for  
 3 Empire's service territory in 2015.

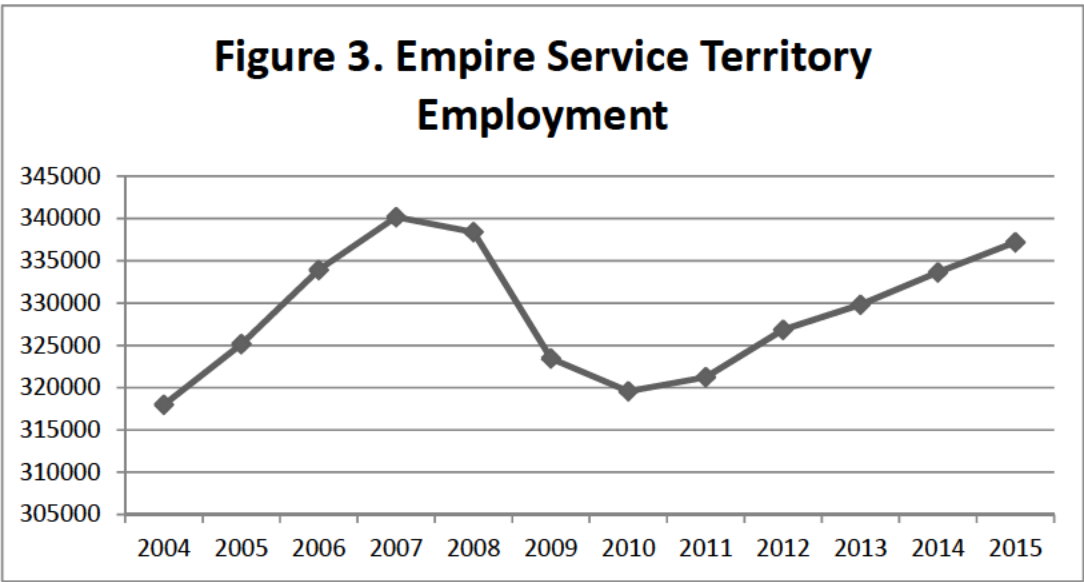
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6 The improved employment situation can also be seen in Figure 3. The preliminary  
 7 numbers for 2015 indicate that employment in Empire's service territory is approaching the 2007  
 8 pre-recession peak.

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1 In addition to examining the status of the current economy, economic forecasters also  
2 examine economic data that have a history of leading, lagging, or coinciding with changes in the  
3 broader economy to anticipate future economic conditions. The current economic outlook from  
4 a variety of economic forecasters has softened since Empire’s last rate case, No. ER-2014-0351.  
5 For instance, the American Institute for Economic Research’s (“AIER”)<sup>7</sup> most recent version of  
6 Business Cycle Conditions (February 2016) shows that 54 percent of the leading indicators are  
7 evaluated as expanding, down from 82 percent in December 2014, which Staff reported in  
8 Empire’s last rate case.<sup>8</sup> In addition, the percentage of expanding coincident indicators fell to  
9 67 percent from 100 percent in December 2014. Under AIER’s method, consistent evaluations  
10 above 50 percent suggest a low probability of recession over the next six to 12 months. It should  
11 be noted that since March 2015, four months have had evaluations at, but not below, 50 percent.  
12 Overall, AIER holds the view that while the U.S. is on a sustainable, moderate growth path,  
13 “the outlook remains fragile given the strong crosscurrents affecting various parts of the  
14 economy.”<sup>9</sup> Further, CITI’s 2016 outlook released December 1, 2015, estimated a 65 percent  
15 chance of a U.S. recession in 2016.<sup>10</sup>

16 Figure 4 provides a comparison of the increase in average weekly wages for the counties  
17 in the Empire service area, Consumer Price Index (“CPI”), Producer Price Index (“PPI”),<sup>11</sup> and  
18 Empire electric rates. From 2007 to 2015, the counties in the Empire service area collectively  
19 experienced a 17.4 percent increase in average weekly wages. This was about one percent (1%)  
20 higher than the overall Missouri compounded increase in average weekly wages of 16.12 percent  
21 and slightly higher than the increase in the CPI. During that same time period, electric rates for

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<sup>7</sup> American Institute for Economic Research. (16FEB16). “Business Conditions Monthly.”  
<https://www.aier.org/bcmoverview2016feb> (16FEB16).

<sup>8</sup> AIER uses 24 indicators in total – 12 leading indicators are a measurable economic factor that tend to change ahead of a turning point in the broader economy, six coincident indicators that tend to change at roughly the same time as a change in the broader economy, and six lagging indicators that tend to change after a turning point in the broader economy. AIER recently revised its list of indicators, details of which can be found at <https://www.aier.org/revising>.

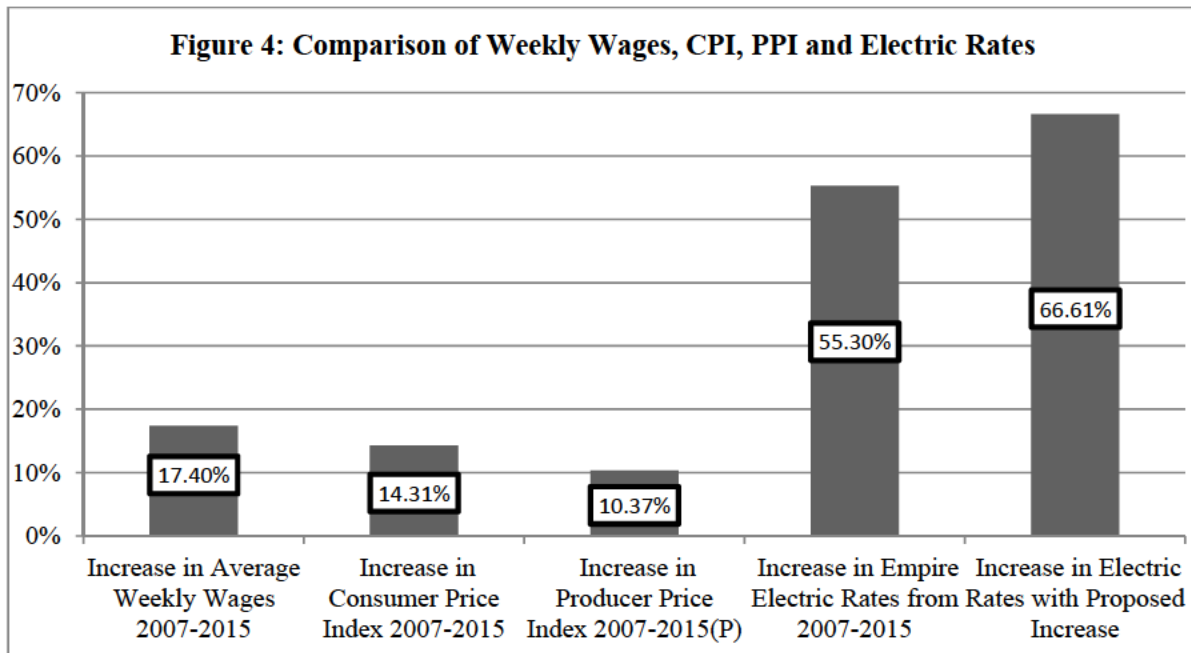
<sup>9</sup> American Institute for Economic Research. (16FEB16). “Business Conditions Monthly.”  
<https://www.aier.org/bcmeconomy2016feb> (16FEB16).

<sup>10</sup> The outlooks are for the U.S. economy in general and may not reflect the outlook in any specific sector.

<sup>11</sup> 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.

1 residential customers served by Empire increased, in Case Nos. ER-2006-0315, ER-2008-0093,  
 2 ER-2010-0130, ER-2011-0004, ER-2012-0345 and ER-2014-0351, a cumulative total of  
 3 55.3 percent, which accumulated to a total increase of approximately \$161.5 million, shown in  
 4 Table 1.

5 Empire has also experienced inflationary pressure illustrated by a 10.37 percent increase  
 6 in the PPI for industrial commodities from 2007 to 2015.<sup>12</sup> However, the PPI for industrial  
 7 commodities decreased 7.21 percent from 2014, largely due to the collapse of energy commodity  
 8 prices. Empire is currently requesting an additional \$33.4 million or a 7.28 percent increase in  
 9 rates. From 2007 to 2015, the increase in average weekly wages for counties in the Empire  
 10 service area is less than one-third of the increase in electric rates for Empire customers.  
 11 If Empire receives its requested 7.28 percent increase, the increase in average weekly wages  
 12 would be just over one-fourth of the increase in electric rates.



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 17 *continued on next page*

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<sup>12</sup> Detailed information on Empire’s expenditures and revenues can be found later in the Staff Cost-of-Service Report.



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Table 1: Empire Rate Case History 2007 - 2015			
Case Number	Effective Date	Dollar Value	Percent Increase
ER-2006-0315	14-Dec-07	\$29,300,000	9.96%
ER-2008-0093	23-Aug-08	\$22,040,395	6.70%
ER-2010-0130	10-Sep-10	\$46,800,000	13.90%
ER-2011-0004	15-Jun-11	\$18,685,000	4.70%
ER-2012-0345	1-Apr-13	\$27,500,000	6.85%
ER-2014-0351	26-Jul-15	\$17,125,000	3.88%
Total Dollars		\$161,450,395	
Total Compounded Increase			55.30%
ER-2016-0023	(Proposed)	\$33,397,363	7.28%
<i>Total with Proposed</i>		<i>\$194,847,758</i>	<i>66.61%</i>

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Lastly, according to the 2009 Residential Energy Consumption Survey,<sup>13</sup> the most recent survey available by the U.S. Department of Energy, Energy Information Administration, Missouri households consume about 12% more energy than the U.S. average. However, the historically lower residential electricity prices result in the average Missouri household paying slightly less for energy than the national average. Overall, the median Missouri household spends about 2.37% of its income on electricity. For households that were identified as being at or below the 150% poverty line, the median increased to 7.68%.

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*Staff Expert/Witness: Michael L. Stahlman*

<sup>13</sup> U.S. Energy Information Administration. (2014). "Residential Energy Consumption Survey." U.S. Department of Energy, [www.eia.gov/consumption/residential/index.cfm](http://www.eia.gov/consumption/residential/index.cfm) (18NOV14).

1 **VII. Rate of Return**

2 **A. Introduction**

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

11 Staff's expert financial analyst, Shana Griffin, estimated Empire's cost of common equity  
12 by applying well-respected and widely-used methodologies to data derived from a carefully-  
13 assembled group of comparable companies, also referred to as the proxy group. Staff then  
14 compared that cost of common equity to Staff's recent estimates of the cost of common equity  
15 estimates for the electric utility industry in the recent Union Electric Company d/b/a Ameren  
16 Missouri ("Ameren Missouri"), Empire and Kansas City Power & Light ("KCPL") rate cases, as  
17 well as an update to the cost of common equity for the same refined electric utility proxy  
18 group,<sup>14</sup> to provide the Commission with a quantitative estimate of a fair and reasonable allowed  
19 ROE for Empire in light of the Commission's recent allowed ROE determinations in the Ameren  
20 Missouri and KCPL rate cases.<sup>15</sup>

21 Staff's multi-stage Discounted Cash Flow ("DCF") analysis shows that the regulated  
22 electric utility industry's cost of equity, as measured by Staff's selected proxy group and  
23 measured by Staff's refined proxy group from the 2014 electric rate cases, has declined by  
24 approximately 20 to 25 basis points since the Ameren Missouri rate case, increased by about  
25 10 basis points since the Empire rate case and 25 basis points since the KCPL rate case.  
26 (*see* Schedule 15). Staff's comparison assumes the use of the same proxy group and same

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<sup>14</sup> Minus Southern Company because it recently announced a proposed major acquisition of AGL Resources, which can distort its stock price.

<sup>15</sup> The cost of common equity is the return required by investors, determined by expert analysis of market data relating to a carefully-constructed group of proxy companies. The allowed ROE, on the other hand, is the value selected by the Commission for use in calculating a utility's forward-looking rates for implementation at the end of the rate case.

1 perpetual growth rates for both periods. Staff notes that if it were to use GDP growth rates as  
2 some witnesses advocate, it would imply a cost of equity that is 25 basis points lower for the  
3 updated analysis. As Staff emphasized in its testimony in the current Missouri American Water  
4 Company rate case, Case No. WR-2015-0301, Staff's quantification of a 25 to 75-basis point  
5 decline in the electric utility industry's Cost of Equity ("COE") in 2014 was benchmarked off of  
6 its initial analysis in the Ameren Missouri 2014 electric rate case, Case No. ER-2014-0258. As  
7 can be seen from the information on Schedule 15, Staff's updated analysis through the Empire  
8 and KCPL rate cases supported an even greater decline in the COE as long-term interest rates  
9 declined considerably through the end of 2014 and into early 2015, which drove up electric  
10 utility price-to-earnings ("P/E") ratios and drove down electric utility dividend yields. Although  
11 Staff believed its updated analysis that incorporated these higher valuation levels supported  
12 approximately a 100-basis point decline in the electric utility industry's COE, Staff continued to  
13 recommend a more conservative reduction of 25 to 75 basis points. The Commission ultimately  
14 decided to authorize ROEs that were approximately 25 basis points below Ameren Missouri's  
15 and KCPL's previously authorized ROEs of 9.80% and 9.70%, respectively.

16 As discussed, Staff's updated analysis in this case shows a lower COE than when Staff  
17 performed its analysis in the Ameren Missouri rate case. If these lower COE indications  
18 continue for the next few months, then this would support even lower allowed ROEs than those  
19 that the Commission authorized last year. However, due to mixed signals between utility debt  
20 markets and equity markets, Staff believes the benchmark the Commission set in 2015 is still a  
21 reasonable starting point for a fair allowed ROE. For purposes of setting Empire's allowed  
22 ROE, the Commission must consider Empire's slightly higher risk level than its Missouri peers.  
23 Based on 'A' rated and 'BBB'/'Baa' rated bond yield spreads data Staff reviewed from Value  
24 Line, Moody's Mergent Bond Record and the Financial Industry Regulatory Authority  
25 ("FINRA"), a 25-basis point risk premium would be appropriate for Empire's allowed ROE.  
26 Staff recommends the Commission set Empire's allowed ROR based on an allowed ROE of  
27 9.50% to 10.00%, mid-point 9.75% (as of the September 30, 2015, update period). The details  
28 of the capital structure and the return components are detailed in the following table:

1

Capital Component	Percentage of Capital	Embedded Cost	Allowed Rate of Return Using Common Equity Return of:		
			9.50%	<b>9.75%</b>	10.00%
Common Stock Equity	48.73%	-----	4.63%	<b>4.75%</b>	4.87%
<u>Long-Term Debt</u>	<u>51.27%</u>	<u>5.33%</u>	<u>2.73%</u>	<b><u>2.73%</u></b>	<u>2.73%</u>
Total	<b>100.00%</b>		7.36%	<b>7.49%</b>	7.61%

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3 The details of Staff’s analysis and recommendations are presented in Schedules 1-17 in  
4 Appendix 2. Staff’s workpapers will be provided to the parties at the time of filing Staff’s Cost  
5 of Service Report. Staff will make any source documents of specific interest available upon the  
6 request of any party to this case or upon the Commission’s request.

7 **B. Analytical Parameters**

8 The determination of a fair rate of return is guided by principles of economic and  
9 financial theory and by certain minimum Constitutional standards. Investor-owned public  
10 utilities such as Empire are private property that the state may not confiscate without  
11 appropriate compensation. The Constitution requires, therefore, that utility rates set by the  
12 government must allow a reasonable opportunity for the shareholders to earn a fair return on  
13 their investment. The United States Supreme Court has described the minimum characteristics  
14 of a Constitutionally-acceptable rate of return in two frequently-cited cases.<sup>16</sup> In *Bluefield*  
15 *Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court  
16 stated:<sup>17</sup>

A public utility is entitled to such rates as will permit it to earn a  
return on the value of the property which it employs for the  
convenience of the public equal to that generally being made at the  
same time and in the same general part of the country on  
investments in other business undertakings which are attended by  
corresponding risks and uncertainties; but it has no constitutional

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<sup>16</sup> *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).

<sup>17</sup> 262 U.S. at 692-693, 43 S.Ct. at 679, 67 L.Ed. at 1176, 1182-83

1 right to profits such as are realized or anticipated in highly  
2 profitable enterprises or speculative ventures. The return should be  
3 reasonably sufficient to assure confidence in the financial  
4 soundness of the utility and should be adequate, under efficient and  
5 economical management, to maintain and support its credit and  
6 enable it to raise the money necessary for the proper discharge of  
7 its public duties. A rate of return may be reasonable at one time  
8 and become too high or too low by changes affecting opportunities  
9 for investment, the money market and business conditions  
10 generally.

11 Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co.*,  
12 the Court stated:<sup>18</sup>

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

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

- 27 1. A return consistent with returns of investments of comparable risk;
- 28 2. A return sufficient to assure confidence in the utility’s financial  
29 integrity; and
- 30 3. A return that allows the utility to attract capital.

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

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<sup>18</sup> 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.

1 The methodologies of financial analysis have advanced greatly since the *Bluefield* and  
2 *Hope* decisions.<sup>19</sup> Additionally, today's utilities compete for capital in a global market rather  
3 than a local market. Nonetheless, the parameters defined in those cases are readily met using  
4 current methods and theory. The principle of the commensurate return is based on the concept of  
5 risk. Financial theory holds that the return an investor may expect is reflective of the degree of  
6 risk inherent in the investment, risk being a measure of the likelihood that an investment will not  
7 perform as expected by that investor. Any line of business carries with it its own peculiar risks  
8 and it follows, therefore, that the return Empire's shareholders may expect is equal to that  
9 required for comparable-risk utility companies.

10 Financial theory holds that the company-specific DCF method satisfies the constitutional  
11 principles inherent in estimating a return consistent with those of companies of comparable  
12 risk;<sup>20</sup> however, Staff recognizes that there is also merit in analyzing a comparable group of  
13 companies as this approach allows for consideration of industry-wide data. Because Staff  
14 believes the cost of equity can be reliably estimated using a comparable group of companies and  
15 the Commission has expressed a preference for this approach, Staff relies primarily on its  
16 analysis of a comparable group of companies to estimate the cost of equity for Empire.

17 In this case, Staff has applied this comparable company approach through the use of both  
18 the DCF method and the Capital Asset Pricing Model ("CAPM"). Properly used and applied in  
19 appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate  
20 estimates of a utility's cost of equity. Because it is well-accepted economic theory that a  
21 company that earns its cost of capital will be able to attract capital and maintain its financial  
22 integrity, Staff believes that authorizing an *allowed* return on common equity based on the  
23 *cost* of common equity is consistent with the principles set forth in *Hope* and *Bluefield*.  
24 However, as Staff will discuss extensively throughout this section of the report, Staff believes it  
25 is common practice for commissions to allow returns on equity that are higher than the costs of  
26 equity for utilities. Consequently, Staff's recommended allowed ROE is higher than Staff's  
27 estimate of Empire's cost of equity.

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<sup>19</sup> Neither the DCF nor the Capital Asset Pricing Model ("CAPM") methods were in use when those decisions were issued.

<sup>20</sup> 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           Because the Commission recently authorized ROEs of 9.53% for Ameren Missouri, and  
2 9.50% for KCPL based on recent economic and capital market conditions, Staff believes it can  
3 best serve the Commission by providing it an estimate of the relative change in regulated electric  
4 utilities' cost of equity in general, since these last rate cases, Case Nos. ER-2014-0258, and  
5 ER-2014-0370 ("the 2014 rate cases"). Although the implied cost of equity based on data  
6 through February 2016 is lower than when Staff provided its recommendation in the Ameren  
7 Missouri rate case, it is higher than when Staff performed its analysis in the Empire and KCPL  
8 rate cases. Additionally, unlike at the end of 2014 and early 2015, utility company bond yields  
9 have not declined as significantly in recent months. Consequently, Staff recommends the  
10 Commission allow Empire an ROE in a range of 9.50 to 10.00 percent with a point estimate of  
11 9.75 percent. Staff's recommended ROE and ROE range for Empire is higher than the ROEs  
12 that were recently authorized in the 2014 rate cases due to Empire's lower credit rating, which is  
13 based on the business and financial risks of Empire's regulated utility operations. Staff added  
14 25 basis points due to Empire's lower credit rating, which is based on the business and financial  
15 risks of Empire's regulated utility operations. Ameren and KCPL have corporate credit ratings  
16 of 'BBB+' while Empire has a corporate credit rating of 'BBB'. The spread between 'A' and  
17 'BBB'/'Baa' rated utility bonds have averaged 45 basis points over the long term.<sup>21</sup> This spread  
18 would normally suggest a 15-basis point risk premium is acceptable for a company rated one  
19 notch lower ( $45/3 = 15$ ). Value Line data shows approximately a 53-basis point spread between  
20 'A' rated and 'BBB'/'Baa' rated bond yields for the twelve weeks ended February 17, 2016.<sup>22</sup>  
21 Staff noticed that recent Mergent Bond Record data showed spreads between 'A' rated and  
22 'BBB'/'Baa' rated utility bonds to be equal to over 100 basis points. Therefore, Staff obtained  
23 the constituent list of the specific bonds that are used in the calculation of Mergent's utility bond  
24 yield averages in order to study why the spreads have recently more than doubled as compared to  
25 the historical average spread. Staff could not verify the methodology used by Mergent to  
26 calculate the bond yield averages. However, it seems that the 'BBB'/'Baa'-rated bond yield  
27 average is skewed higher due to the energy bonds included in the averages. Using data from  
28 FINRA, for the twelve weeks ended March 14, 2016, Staff calculated what the average 'A' rated

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<sup>21</sup> Mergent Bond Record data shows from January 1996 to January 2016 the average spread between 'A' rated and 'BBB'/'Baa' rated utility bond yields has averaged 45 basis points.

<sup>22</sup> Value Line Selection & Opinions December 11, 2015 through February 26, 2016, except for the February 5, 2016, Selection & Opinion because it was unavailable to Staff at the time of testimony.

1 and ‘BBB’/‘Baa’ rated utility bond yields would be using Mergent’s constituent list excluding  
2 the energy companies. Staff found that the average spread would be approximately 65 basis  
3 points when the energy companies are excluded. This spread would suggest approximately a  
4 22-basis point risk premium is acceptable for a company rated one notch lower ( $65/3 = 21.67$ ).  
5 Therefore, because of the recent increase in spreads between ‘A’ and ‘BBB’/‘Baa’ rated utility  
6 bonds, Staff recommends a 25-basis point adjustment.

## 7 **C. Current Economic and Capital Market Conditions**

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

### 13 **1. Economic Conditions**

14 Although economic growth was positive in 2015, this growth has been fairly low.  
15 Real GDP increased by 0.6 percent in the first quarter, 3.9 percent in the second quarter, 2.0  
16 percent in the third quarter and 1.0 percent in the fourth quarter. Real GDP increased 2.4 percent  
17 in 2015. The Commerce Department revised its fourth quarter GDP estimate up from an earlier  
18 estimate of 0.7 percent.<sup>23</sup> As of December 2015, the Federal Reserve Board (“Fed”) Members  
19 and the Federal Reserve Bank Presidents projected real GDP would grow between 2.3 and  
20 2.5 percent in 2016, 2.0 and 2.3 percent in 2017, and 1.8 and 2.2 percent in 2018. The longer run  
21 projections for real GDP growth were between 1.8 and 2.2 percent.<sup>24</sup>

22 Although the Fed increased the Fed Funds rate at its December 15-16 meeting, it appears  
23 that the Fed will need to be very careful about how quickly it increases the Fed Funds rate due to  
24 the fragile economy. Although some believed that an increase in the Fed Funds rate would cause  
25 an increase in long-term rates, this did not happen. Long-term rates typically are much more a  
26 function of the market and economic forces rather than monetary policy influence. In fact, many  
27 market participants believed long-term rates would increase when the Fed terminated its

---

<sup>23</sup> <http://www.bea.gov/national/index.htm#gdp>. “Real” GDP is adjusted to reflect inflation.

<sup>24</sup> <http://www.federalreserve.gov/monetarypolicy/files/fomeprojt20151216.pdf>.



1 bond-buying program in October 2014. However, market forces driven by the impact of falling  
2 energy prices, slowing growth in China, economic, financial concerns in European countries,  
3 and lowered economic growth outlooks for United States, caused a decline in long-term rates  
4 after the Fed terminated its bond-buying program. This caused utility stock prices to increase  
5 dramatically at the end of 2014 and into early 2015. Going forward, one of the key areas of  
6 interest for the markets in general, but utilities in particular, is whether an increase in the  
7 Fed Funds rate will cause an increase in financing costs. The answer has been *yes* for short-term  
8 financing instruments, but no for long-term financing instruments.

9 A recent *WSJ* article<sup>25</sup> stated:

10 The risks to growth, and hiring now don't look so threatening, in part  
11 because financial conditions have improved. Stocks have recovered some  
12 lost ground after falling in January and early February. Meantime, long-  
13 term interest rates dropped, in part because investors have come to see the  
14 Fed keeping rates lower than previously expected.

15 Information released from the Federal Open Market Committee ("FOMC") meeting held on  
16 January 27, 2016, shares the FOMC's intention regarding any future changes in the Fed Funds  
17 Rate. The following excerpt from the FOMC's press release provides direct comments from the  
18 FOMC regarding its views:

19 ...Given the economic outlook, the Committee decided to maintain the  
20 target range for the federal funds rate at 1/4 to 1/2 percent. The stance of  
21 monetary policy remains accommodative, thereby supporting further  
22 improvement in labor market conditions and a return to 2 percent inflation.

23 In determining the timing and size of future adjustments to the target range  
24 for the federal funds rate, the Committee will assess realized and expected  
25 economic conditions relative to its objectives of maximum employment  
26 and 2 percent inflation. This assessment will take into account a wide  
27 range of information, including measures of labor market conditions,  
28 indicators of inflation pressures and inflation expectations, and readings  
29 on financial and international developments. In light of the current  
30 shortfall of inflation from 2 percent, the Committee will carefully monitor  
31 actual and expected progress toward its inflation goal. The Committee  
32 expects that economic conditions will evolve in a manner that will warrant  
33 only gradual increases in the federal funds rate; the federal funds rate is  
34 likely to remain, for some time, below levels that are expected to prevail

---

<sup>25</sup> Jon Hilsenrath, "Fed Seen Emphasizing Flexibility," *Wall Street Journal*, p. A2, March 9, 2016.

1 in the longer run. However, the actual path of the federal funds rate will  
2 depend on the economic outlook as informed by incoming data...<sup>26</sup>

3 The Fed continues to target a 2-percent inflation rate. The economic outlook will determine how  
4 the Fed chooses to increase the federal funds rate, but we are likely to see only gradual increases  
5 in the federal funds rate.

## 6 **2. Capital Market Conditions**

### 7 **a. Utility Debt Markets**

8 Utility debt markets indicate a slightly higher cost-of-capital environment than that which  
9 existed when the Commission determined an allowed ROE of approximately 9.5% was fair for  
10 KCPL and Ameren Missouri. The average utility bond yields, as reported in the Mergent Bond  
11 Record, at the time Staff recommended the Commission lower Ameren Missouri's allowed ROE  
12 by 25 to 75 basis points, were approximately 4.3%. Average utility bond yields declined to a  
13 recent historical low of 3.83% in January 2015. Since January 2015, average utility bond yields  
14 have been increasing. At approximately the time the hearings in the KCPL rate case began,  
15 average utility bond yields were slightly higher than they were when Staff performed its analysis  
16 in the Ameren Missouri rate case. The average utility bond yield for the last three months  
17 through January 2016 was approximately 4.68%, which is approximately 40 basis points higher  
18 than when Staff recommended the Commission reduce Ameren Missouri's allowed ROE by  
19 25 to 75 basis points.

20 Although the average utility bond yields indicate an increase in the cost of capital, the  
21 utility bond yield data, broken down by category, indicate that the increase in the cost of capital  
22 is much more pronounced for utilities that have a weaker investment grade credit rating, *i.e.*,  
23 a 'BBB' rating rather than an 'A' rating. Schedule 4-5 shows the average yields on 'A' rated  
24 utility bonds versus 'BBB'/'Baa' rated utility bonds since January 1, 2014. Typically the spread  
25 between 'A' rated utility bonds and 'BBB'/'Baa' rated utility bonds is 45 basis points over the  
26 long-term. However, since the time Staff did its analysis in the Ameren Missouri rate case, this  
27 spread has more than doubled to over 100 basis points.

28 Although the spread between 'BBB'/'Baa'-rated utility bond and 'A'-rated utility bonds  
29 published in the Mergent Bond Record seemed consistent with Staff's understanding of issues

---

<sup>26</sup> Federal Reserve Press Release January 27, 2016.

1 causing lower grade bonds to have a much higher Yield to Maturity (“YTM”), the spread was  
2 much higher than what seemed to be reasonable for fairly stable utility bonds, especially  
3 considering the mixed message of increases in utility stock prices, but declines in utility bond  
4 prices, at least implied in the Mergent Bond Record. Staff also understood that the energy  
5 sector, which includes energy pipeline operators and merchant generation operators, has been  
6 experiencing significant volatility in capital market prices. Many of these energy companies are  
7 often broadly classified as “utilities” for purposes of various stock and bond indices.

8 Consequently, Staff pursued additional information from Mergent Bond Record as to the  
9 underlying bonds that make up the current Moody’s public utility bond averages that are used in  
10 Mergent Bond Record. The information provided by Mergent showed that energy pipeline  
11 companies with significant exposure to the commodity price volatility were classified as  
12 “utilities” and were still rated ‘Baa’ (Moody’s equivalent of Standard & Pooors’ (“S&P”) ‘BBB’  
13 rating). A few examples of the energy companies’ bonds that are included in the Moody’s ‘Baa’  
14 public utility bond yield index are: El Paso Pipeline Partners, Energy Transfer Partners LP,  
15 Enlink Midstream Partners LP, Kinder Morgan Energy Partners, and Williams Partners LP.  
16 It has been fairly widely recognized in the financial community that these companies’ security  
17 prices have been very volatile and declined significantly. For example, El Paso Pipeline  
18 Partners’ bond<sup>27</sup> has traded at YTM’s of around 7% during February 2016; Energy Transfer  
19 Partners LP’s bond<sup>28</sup> has traded at YTM’s of around 8% during February 2016; Williams  
20 Partners LP’s bond<sup>29</sup> has traded at YTM’s of around 8.5% during February 2016; and Enlink  
21 Midstream Partners LP’s bond<sup>30</sup> has traded at YTM’s close to 11% around February 24, 2016  
22 (this is the highest YTM of the bonds in the index).

23 The energy company bonds in the Moody’s ‘BBB’/‘Baa’ rated “utility” index make up  
24 7 of the 18 bonds in the index. Staff requested Mergent provide information on the methodology  
25 it uses to calculate its utility bond yield averages, but Mergent considered this information to be  
26 proprietary. However, removing these energy related “utility” bonds from the index would cause

---

<sup>27</sup> CUSIP: 28370TAF6.

<sup>28</sup> CUSIP: 29273RAZ2.

<sup>29</sup> CUSIP: 96950FAN4.

<sup>30</sup> CUSIP: 29336UAC1.

1 the average utility bond yield average to decrease since the rest of the bonds in the index trade in  
2 the 4.5% to 5.5% range,<sup>31</sup> which is more typical of investment grade regulated utility bonds.

3 The average 'A' rated utility bond yield at the time Staff performed its cost of capital  
4 analysis in the Ameren Missouri rate case was about 4.15%,<sup>32</sup> whereas the average 'A' rated  
5 utility bond yield for the three months through January 2016 was 4.34%, an increase of  
6 approximately 20 basis points. The average 'BBB'/'Baa' rated utility bond yield at the time  
7 Staff performed its cost of capital analysis in the Ameren Missouri case was approximately  
8 4.70%,<sup>33</sup> whereas the average 'BBB'/'Baa' rated utility bond yield for the three months through  
9 January 2016 was 5.54%, an increase of 84 basis points. Although Staff could not verify the  
10 methodology used by Mergent to calculate the bond yield averages, it seems that the  
11 'BBB'/'Baa'-rated bond yield average is skewed higher due to the energy bonds included in the  
12 averages. For the most recent 3 months through January 2016, the average spread between 30-  
13 year T-bonds (2.95 %) and average utility bond yields (4.68 %) was 173 basis points. For the  
14 three months ended October 2014, the average spread between 30-year T-bonds (3.17%) and  
15 average utility bond yields (4.31%)<sup>34</sup> was 114 basis points. The spread has increased by 59 basis  
16 points since the three months ended October 2014. This is explained by the increase in utility  
17 bond yields and the decline in 30-year T-bonds. (*See Schedules 4-3 and 4-4*).

#### 18 **b. Utility Equity Markets**

19 For the twelve months ending December 31, 2015, the total return on the Dow Jones  
20 Industrial Average ("DJIA") was .2%, the total return on the Standard & Poor's 500  
21 ("S&P 500") was 1.4%, and the total return on the Edison Electric Institute ("EEI") Index of  
22 electric utilities was -3.9%.<sup>35</sup> EEI's Stock Performance Q4 2015 Financial Update stated the  
23 following:

24 The EEI Index gained 1.6% in Q4 while the broad markets  
25 reversed Q3 losses and gained 7% and 8%. Rising interest rates in  
26 the year's first half and weak natural gas prices during the year led

---

<sup>31</sup> Data from FINRA from December 21, 2015 through March 14, 2016.

<sup>32</sup> Average monthly yield for August, September and October 2014.

<sup>33</sup> Average monthly yield for August, September and October 2014.

<sup>34</sup> Mergent Bond Record.

<sup>35</sup> EEI Stock Performance 2015 Q4 Financial Update.

1 to a -3.9% full-year return for the EEI Index, the first negative  
2 return since 2008.

3 The share prices of regulated utilities continued to be supported  
4 through 2015 by low interest rates and sturdy dividend yields  
5 (about 4% for the industry as a whole).

6 The trend that has shaped utility share performance relative to the  
7 broad market for six years seems likely to continue: it will be tied  
8 less to slow-changing industry business fundamentals than faster-  
9 changing macroeconomic developments, whether relating to  
10 economic data, interest rates, oil prices, and other macro or  
11 geopolitical events that spur bullish or bearish market moves.

### I. Index Comparison (% Return)

Index	2009	2010	2011	2012	2013	2014	2015
EEI Index	10.7	7.0	20.0	2.1	13.0	28.9	-3.9
Dow Jones Inds.	22.7	14.1	8.4	10.2	29.6	10.0	0.2
S&P 500	26.5	15.1	2.1	16.0	32.4	13.7	1.4
Nasdaq Comp.^	43.9	16.9	-1.8	15.9	38.3	13.4	5.7

Calendar year returns shown for all periods, except where noted.

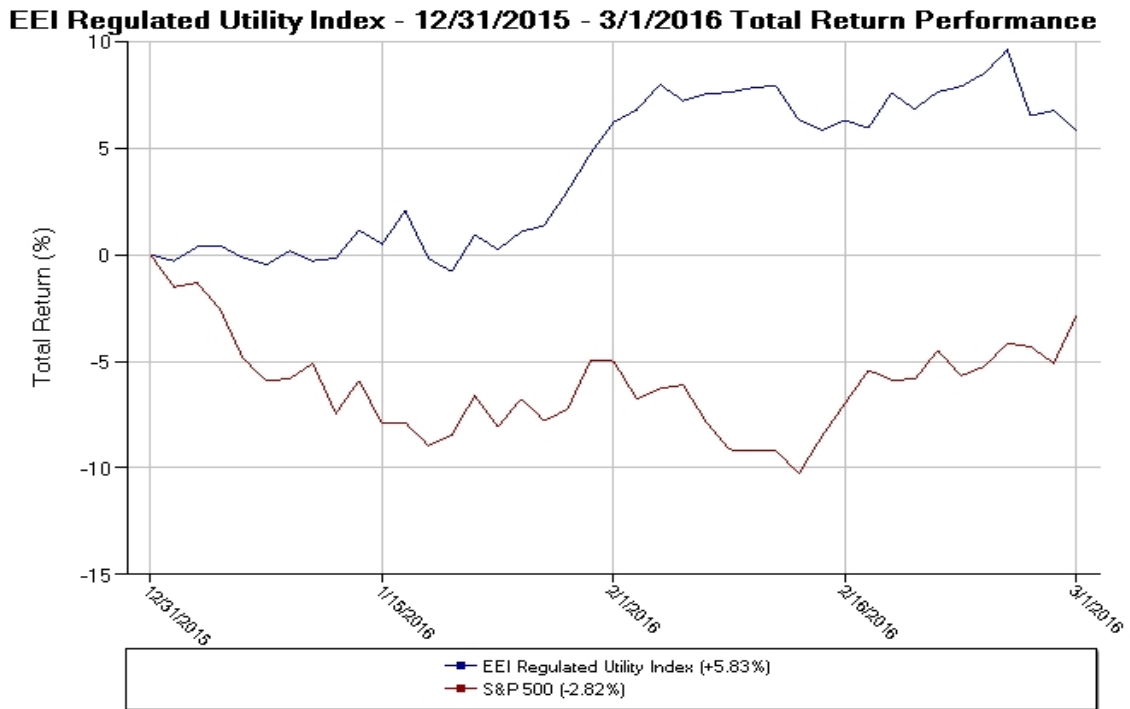
^Price gain/loss only. Other indices show total return.

Source: EEI Finance Department

15 EEI Index returns during 2015 embodied the larger pattern seen in  
16 Table 1 since the 2008/2009 financial crisis, as industry business  
17 models have migrated to an increasingly regulated emphasis. The  
18 industry has generated consistent positive returns but has lagged  
19 the broader markets when markets post strong gains, which in turn  
20 have been sparked both by slow but steady U.S. economic growth  
21 and corporate profit gains and by the willingness of the Federal  
22 Reserve to bolster markets with historically unprecedented  
23 monetary support in the form of three rounds of quantitative easing  
24 and near-zero short-term interest rates. While the Fed did raise  
25 short-term interest rates in December 2015 for the first time since  
26 2006 (from zero to a range of 0.25% to 0.50%), **this hardly effects**  
27 **longer-term yields**, which remain at historically low levels and are  
28 influenced more by the level of inflation and economic strength  
29 than by the Fed's short-term rate policy. (emphasis added)  
30  
31  
32  
33

34  
35  
36  
37 *continued on next page*

1 So far in 2016 the EEI Regulated Utility Index has outperformed the S&P 500:

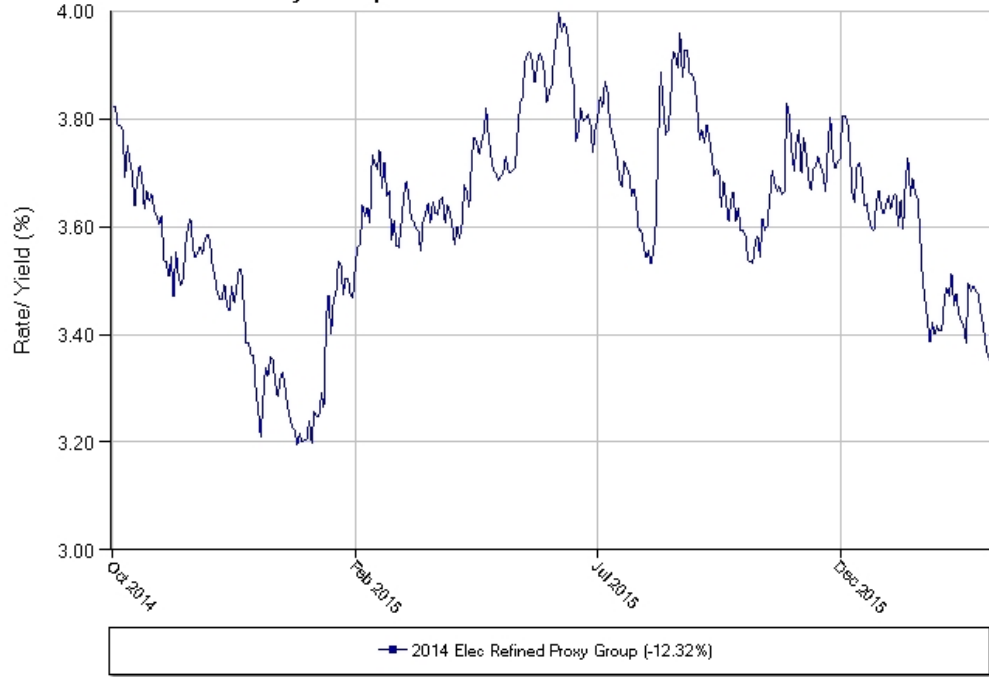


2  
3 As Staff explained in its testimonies in the 2014 electric utility rate cases testimonies and as  
4 confirmed by EEI's commentary, utility stock returns are highly correlated to changes  
5 in long-term yields. This proved to be the case during the fourth quarter of 2014 and early 2015.  
6 It is also proving to be the case since the beginning of 2016 as shown in the chart above.  
7 The increase in utility stock prices causes declines in dividend yields and increases in P/E ratios.  
8 As you can see in the charts below, the dividend yields have decreased for the 2014 refined  
9 electric proxy group since the beginning of 2016 and the P/E ratios have increased, implying a  
10 lower COE.

11  
12  
13  
14  
15  
16  
17 *continued on next page*

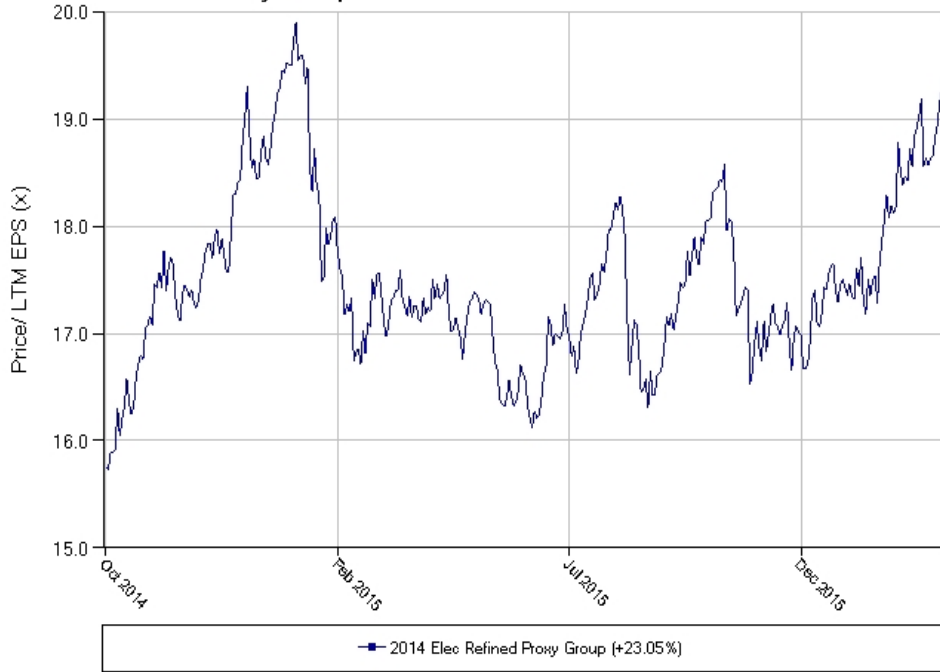
1

2014 Elec Refined Proxy Group - 10/1/2014 - 3/10/2016 Rate/ Yield Performance



2

2014 Elec Refined Proxy Group - 10/1/2014 - 3/10/2016 Price/ LTM EPS Performance



3

1 In the fall of 2014 to early 2015, it was clear that higher utility P/E ratios were being  
2 driven by the decline in interest rates, which made it very convincing that the cost of equity had  
3 declined. The other factor that often explains an increase in valuation ratios is a higher expected  
4 growth rate in one period as compared to another. The 2014 electric proxy group's FactSet long  
5 term projected Earnings Per Share ("EPS") growth rate was approximately 5.69% at the time of  
6 the 2014 rate cases and for this case the same proxy group's FactSet long term projected EPS  
7 growth rate is 5.56%. Considering the fact that P/E ratios have increased since the fall of 2014  
8 and this is not due to an increase in expected long-term growth, this certainly implies that if  
9 anything, the COE for electric utilities may be a little lower since the Commission ordered an  
10 ROE of 9.50% for the 2014 cases. Therefore, an allowed ROE consistent with the Commission's  
11 decisions in 2015 based on 2014 is still fair and reasonable.

#### 12 **D. Empire's Operations**

13 The following excerpt from Empire's Form 10-K filing with the United States Securities  
14 and Exchange Commission ("SEC") for the year ended December 31, 2015, provides a good  
15 description of Empire's current business operations:

16 We operate our businesses as three segments: electric, gas and other. The  
17 Empire District Electric Company (EDE), a Kansas corporation organized  
18 in 1909, is an operating public utility engaged in the generation, purchase,  
19 transmission, distribution and sale of electricity in parts of Missouri,  
20 Kansas, Oklahoma and Arkansas. As part of our electric segment, we also  
21 provide water service to three towns in Missouri. The Empire District Gas  
22 Company (EDG) is our wholly owned subsidiary engaged in the  
23 distribution of natural gas in Missouri. Our other segment consists of our  
24 fiber optics business.

25  
26 Our gross operating revenues in 2015 were derived as follows:

27	Electric segment sales*	91.7%
28	On-system revenues	86.6%
29	SPP IM revenues	2.5
30	Other revenues	2.3
31	Gas segment sales	6.9
32	Other segment sales	1.4

33 \*Sales from our electric segment include 0.5% from the sale of water.

34  
35 On-system electric revenues consist of residential, commercial, industrial,  
36 wholesale on-system and other (which includes street lighting, other  
37 public authorities and interdepartmental usage).  
38



1 The territory served by our electric operations embraces an area of about  
2 10,000 square miles, located principally in southwestern Missouri, and  
3 also includes smaller areas in southeastern Kansas, northeastern Oklahoma  
4 and northwestern Arkansas. The principal economic activities of these  
5 areas include light industry, agriculture and tourism. As of December 31,  
6 2015, our electric operations served approximately 170,000 customers.  
7

8 Our retail electric revenues for 2015 by jurisdiction were derived as  
9 follows:

10 Missouri	89.0%
11 Kansas	4.8
12 Oklahoma	2.8
13 Arkansas	3.4

14  
15 We supply electric service at retail to 119 incorporated communities as of  
16 December 31, 2015, and to various unincorporated areas and at wholesale  
17 to four municipally owned distribution systems. The largest urban area we  
18 serve is the city of Joplin Missouri, and its immediate vicinity, with a  
19 population of approximately 160,000.

## 20 **E. Empire's Credit Ratings**

21 Empire is currently rated by Moody's and S&P. It is important to understand the current  
22 credit standing of Empire, as these ratings influence investors' views of the risk associated with  
23 investing in Empire.

24 Empire's Moody's corporate credit rating is 'Baa1' and its S&P corporate credit rating is  
25 'BBB.'<sup>36</sup> The following is an excerpt from S&P's February 10, 2016, credit-rating report on  
26 Empire, discussing S&P's rationale for revising their outlook on Empire to "negative" and  
27 affirming their ratings:

28 We base the negative outlook on Empire's announcement that it has  
29 entered into an agreement to be acquired by Algonquin Power & Utilities  
30 Corp. When the transaction closes, we would view Empire as a core  
31 subsidiary of Algonquin, leading to an issuer credit rating for Empire that  
32 is aligned with that of Algonquin. We base this assessment on the  
33 following factors:

- 34  
35 •We project that Empire will form a meaningful part of the merged  
36 entity, contributing about 40% of Algonquin's EBITDA.  
37

---

<sup>36</sup> Empire's SEC Form 10-K filing for the year ended December 31, 2015, p.5.

1 •Empire operates in lines of business that are integral to the overall  
2 group strategy (regulated utility operations).  
3

4 •We expect Algonquin’s management will be strongly committed  
5 to Empire given Algonquin’s emphasis on maintaining the size and  
6 scope of its regulated utility operations relative to nonutility  
7 operations.  
8

9 •Empire will enhance Algonquin’s presence in common service  
10 territories, especially Missouri, facilitating growth and cost-  
11 reduction opportunities.  
12

13 Because of our view of Empire’s core group status, the negative outlook  
14 on Empire is in line with the negative outlook on Algonquin, which  
15 reflects the risk of weaker near-term credit measures associated with the  
16 transaction’s timing and financing.  
17

18 The ratings on Empire are based on the company’s strong business and  
19 significant financial risk profiles.  
20

21 We assess Empire District’s business risk profile as strong, reflecting the  
22 company’s historically effective management of regulatory risk, limited  
23 service territory that lacks scale and regulatory and operating diversity,  
24 and efficient operations. Although the regulatory framework has been  
25 somewhat challenging in the past, especially in terms of rate-case lag that  
26 affects the company’s ability to earn its authorized return, Empire has  
27 nonetheless endeavored to reach constructive regulatory outcomes, thus  
28 supporting its overall credit profile.

## 29 **F. Algonquin’s Proposed Acquisition of Empire**

30 At this time, Staff does not know how Algonquin plans to structure the acquisition of  
31 Empire and how it will finance its operations if it is allowed to acquire Empire. However, the  
32 proposed Algonquin acquisition of Empire has not impacted Staff’s recommended ROR in this  
33 case. Empire’s S&P credit rating is on a “negative” outlook due to the proposed acquisition.  
34 However, the embedded cost of debt is not impacted because this debt was issued prior to the  
35 announcement of the proposed acquisition. Staff used the actual, consolidated capital structure  
36 of Empire as of September 30, 2015, as the basis for its capital structure recommendation.  
37 Empire’s capital structure was not impacted by the announcement of the proposed acquisition as  
38 of that date. Staff’s recommended allowed ROE has not been influenced by the announcement

1 of the proposed acquisition because Empire is not included in Staff's current proxy group or the  
2 2014 refined proxy group.

3 Although Staff's ROR recommendation in this case is not impacted by Algonquin's  
4 proposed acquisition of Empire, Staff notes that Algonquin is proposing to pay a significant  
5 premium for Empire's stock. This significant premium is consistent with premiums proposed in  
6 other recently announced transactions. It is widely recognized in the investment community that  
7 these larger premiums are being driven by higher valuation levels caused by the low cost of  
8 capital environment. Staff urges the Commission to take this into consideration when evaluating  
9 the credibility of the various witnesses' cost of equity estimates.

## 10 **G. Cost of Capital**

11 In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an  
12 appropriate ratemaking capital structure, (2) the Company's embedded cost of debt, and (3) an  
13 evaluation of a fair and reasonable allowed ROE in light of the Commission's recent decisions in  
14 the Ameren Missouri and KCPL rate cases.

### 15 **1. Capital Structure**

16 Schedule 5 presents Empire's historical capital structures in dollar terms and percentage  
17 terms for the years 2011 through 2015.

18 Staff used the actual, consolidated capital structure of Empire as of September 30, 2015,  
19 as the basis for its capital structure recommendation. Schedule 7 presents Empire's capital  
20 structure and associated capital ratios. Staff's resulting ratemaking capital structure  
21 recommendation consists of 48.73 percent common equity and 51.27 percent long-term debt.

22 Staff should also note that the recommended ratemaking capital structure does not  
23 contain short-term debt. This is not because Empire does not issue short-term debt for purposes  
24 of funding its operations. Staff did not include Empire's short-term debt in the capital structure  
25 because for the twelve months ending September 30, 2015, Empire's average Construction Work  
26 in Progress ("CWIP") balance exceeded its short-term debt balance. Therefore, it is assumed  
27 that the short-term debt was used to fund CWIP.

1                                   **2. Embedded Cost of Debt**

2                   Staff’s embedded cost of long-term debt of 5.33 percent is based on information provided  
3 by Empire in response to Staff Data Request Nos. 0089 and 0090. Staff’s embedded cost of  
4 long-term debt is slightly lower than that provided by Empire because Staff proposes to disallow  
5 the remaining unamortized expense balance of approximately \$1,371,065 associated with  
6 Empire’s \$2.5 million of debt expenses incurred to amend its mortgage bond indenture in order  
7 to provide additional flexibility to pay its dividend. Staff subtracted this amount from Empire’s  
8 cost of debt calculation for the period ending September 30, 2015. Staff has consistently  
9 proposed this disallowance in Empire’s past rate cases as well. Staff provides the underlying  
10 details of its embedded cost of debt estimate in Schedule 6.

11                                   **3. Cost of Common Equity**

12                   Staff estimated Empire’s cost of common equity through a comparable company cost-of-  
13 equity analysis of a proxy group using the DCF method. Additionally, Staff used a CAPM  
14 analysis and a survey of other indicators as a check of the reasonableness of its  
15 recommendations.

16                                   **a. The Proxy Group**

17                   The ultimate goal of selecting a proxy group is to select companies whose operations are  
18 confined as much as possible to regulated utility operations (“pure-play regulated utilities”/  
19 “pure-play”) with a majority of the regulated utility operations being that of the electric  
20 utility sector.

21                   Starting with 66 market-traded companies classified as power companies by  
22 SNL Financial, Staff applied a number of criteria to develop a proxy group comparable in risk to  
23 Empire’s regulated electric utility operations (*see* Schedule 8). Staff’s criteria are designed to  
24 capture companies with primarily regulated electric operations (which means the companies’  
25 operations may have other regulated operations, such as gas distribution), and whose electric  
26 utility operations contain a significant amount of generation assets. Staff’s criteria accomplished  
27 this objective. Staff will show the results of the current proxy group and the 2014 refined proxy  
28 group in each of its schedules. Staff’s criteria are as follows:<sup>37</sup>

---

<sup>37</sup> Staff used 2015 data from SNL if it was available, otherwise Staff used 2014 SNL data.

- 1 1. Classified as a power company by SNL (66 companies);
- 2 2. Publicly-traded stock (one company eliminated, 66 remaining);
- 3 3. Followed by EEI and classified by EEI as a regulated utility
- 4 (33 companies eliminated, 33 remaining);
- 5 4. At least 50% of plant from electric utility operations (3 companies
- 6 eliminated, 30 remaining);
- 7 5. At least 25% of electric plant from generation (5 companies
- 8 eliminated, 25 remaining);
- 9 6. At least 80% of income from regulated utility operations
- 10 (1 company eliminated, 24 remaining);
- 11 7. No reduced dividend since 2013 (0 companies eliminated,
- 12 24 remaining);
- 13 8. At least investment grade credit rating (0 companies eliminated,
- 14 24 remaining);
- 15 9. At least 2 equity analysts providing long-term growth projections
- 16 in the last 90 days (5 companies eliminated, 19 remaining);
- 17 10. No significant merger or acquisition announced recently
- 18 (4 companies eliminated, 15 remaining).

19 The resulting final group of 15 publicly-traded electric utility companies (“the comparables”) was used to estimate a cost of common equity for the electric utility industry. These companies are shown on Schedule 8.

#### 22 **b. The Constant-growth DCF**

23 Next, Staff estimated Empire’s cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.<sup>38</sup> It may be expressed algebraically as follows:

---

<sup>38</sup> 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.

1 
$$k = D_1/P_0 + g$$

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

6 The term  $D_1/P_0$ , the expected next 12-months' dividend divided by current share price,  
7 is the dividend yield. Staff calculated the dividend yield for each of the comparable companies  
8 by dividing the 2016 fiscal year FactSet projected dividends per share (*see* Schedule 12) by  
9 the monthly high/low average stock price for the three months ending February 2016.  
10 (*See* Schedule 11).<sup>39</sup> Staff used the above-described stock price because it reflects current  
11 market expectations. The projected average dividend yield for the current proxy group of fifteen  
12 comparable companies is 3.78%, unadjusted for quarterly compounding.

13 **i. The Inputs**

14 In the DCF method, the cost of equity is the sum of the dividend yield and a  
15 growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a  
16 growth rate, Staff considered the actual dividends per share ("DPS"), EPS and book value per  
17 share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and  
18 BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be quite  
19 volatile, at least for a few of the companies in the proxy group.<sup>40</sup> Staff also reviewed equity  
20 analysts' consensus estimates for long-term compound annual growth rates as reported by  
21 FactSet and provided by SNL Financial. The average consensus long-term growth rates for the  
22 current proxy group is currently 5.12 %. (*See* Schedule 10-6).

23 Based on the shorter-term projected EPS growth rate data, one may argue that electric  
24 utilities can grow at a rate of approximately 5.15 percent, but it would be unreasonable to

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<sup>39</sup> 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.

<sup>40</sup> Schedule 10-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 10-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

1 conclude that this growth rate is sustainable in perpetuity because it does not give consideration  
2 to empirical and logical information that suggests that utility companies should grow at a rate  
3 less than that of the overall economy.

4 Historical data also indicates that companies in the S&P 500 (a proxy for the U.S. capital  
5 markets) have retained over 60% of their earnings for reinvestment since January 1, 2009,<sup>41</sup>  
6 while electric utilities' retention ratio has been less than half that of the S&P 500,<sup>42</sup> it makes  
7 logical sense that utilities will grow at a rate less than that of nominal GDP growth.  
8 Consequently, a projected long-term, steady-state nominal GDP growth rate<sup>43</sup> should be  
9 considered as an upper constraint when testing the reasonableness of growth rates used to  
10 estimate the cost of equity for a regulated electric utility. Staff will provide more detail on  
11 economic growth projections when discussing the multi-stage DCF, but a high-end estimate for  
12 nominal GDP is not much higher than 4.30%, causing an estimated constant growth rate over  
13 this rate to be highly suspect.

14 Because Staff is not relying on the constant-growth DCF to quantify the change in the  
15 cost of equity since the 2014 rate cases, Staff's growth rate estimate for the constant growth DCF  
16 is based on some common sense restraints on sustainable growth rates and the actual growth  
17 experience of the electric utility companies that have experienced more stable growth patterns.  
18 Considering that actual long-term growth experience in the electric utility industry barely  
19 supports a constant growth rate much more than 3%, Staff will use 3.5% as the low end and  
20 4.5% for the high end investors' expectations of a constant growth rate.

21 Using the growth rate range Staff established for the constant-growth DCF results in a  
22 cost of equity estimate of 7.3% to 8.3%. However, Staff will again rely on its multi-stage DCF  
23 analysis to provide what it believes to be a more reliable cost of common equity due to the  
24 non-sustainable growth rates of a few companies in its proxy group.

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<sup>41</sup> <http://www.spindices.com/indices/equity/sp-500>.

<sup>42</sup> <http://www.wyattresearch.com/article/dividend-payout-ratio>.

<sup>43</sup> The nominal GDP growth rate, contrasted to the real GDP growth rate introduced earlier, is not adjusted for inflation.





1 of assumptions, Staff’s estimated cost of equity for the current proxy group ranges from  
2 approximately 7.38% to 8.15%, mid-point of 7.76%.

3 **ii. Stage one**

4 The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast  
5 cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of  
6 a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next  
7 several years. However, in the context of discounting expected future DPS, it is often the case  
8 that a compound growth rate is applied to the current DPS to estimate the expected DPS over the  
9 next several years. Although it is rare for a company to tie its targeted DPS growth rate directly  
10 to a 5-year EPS projected compound growth rate, because equity analysts’ 5-year EPS forecasts  
11 are widely available and may provide some insight on expected DPS, Staff decided to use these  
12 growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has  
13 **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for  
14 purposes of estimating the growth in DPS in a single-stage, constant-growth DCF or for the final  
15 stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year  
16 EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in  
17 their own analyses should be proof in and of itself that stock prices do not reflect this  
18 assumption. Consequently, Staff limited its use of these growth rates to the first five years of its  
19 analysis, the very period these growth rates are intended to cover.

20 **iii. Stage two**

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

27 **iv. Stage three**

28 Stage three is the final/constant-growth stage. In fact, the final stage can be reduced to  
29 the single-stage, constant-growth form of the DCF. Although this is the “generic” stage, it is

1 extremely important to select a reasonable growth rate for this stage to arrive at a reliable cost of  
2 equity estimate.

3 Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to  
4 the assumed perpetual growth rate. Staff performed an extensive amount of research on the  
5 actual realized growth rates of electric utilities over a 30-year period to estimate a 3.00% to  
6 4.00% growth rate as a reasonable proxy for perpetual growth for the electric utility industry.

7 The Financial Analysis Unit has access to Value Line data on *Central* region electric  
8 utility companies dating back to 1968.<sup>47</sup> Staff believes it is important to analyze electric utility  
9 industry financial data to at least the early 1970s since this was approximately the beginning of  
10 the last large construction cycle for the electric utility industry.<sup>48</sup> Because 1968 is consistent  
11 with the starting point of the last construction cycle, Staff decided to capture data starting in that  
12 year. Ideally, Staff would have analyzed data through the beginning of the current construction  
13 cycle, which started approximately during the middle of the past decade, but because many  
14 electric utility companies diversified into non-regulated merchant and trading operations towards  
15 the end of the 1990s and there was much consolidation during this same period, this noise causes  
16 any study relying on this more recent data to be less reliable in evaluating *regulated* electric  
17 utility growth rates. It appears that much of the disruption in the electric industry occurred  
18 subsequent to the Enron, Inc., bankruptcy in December 2001. Considering that much of this  
19 disruption was caused by deregulation, Staff does not consider the information during this  
20 period to be informative for understanding investors' growth expectations for regulated electric  
21 utility operations.

22 Staff did not apply rigid selection criteria for purposes of selecting central region electric  
23 utility companies contained in Edition 5 of the Value Line Investment Survey. However, Staff  
24 did eliminate companies that generally did not have at least 70% of revenues from electric utility  
25 operations in the late 1990s. Staff also eliminated companies that appeared to be impacted  
26 significantly by events related to the restructuring of the electric utility markets in the mid to late  
27 1990s. Staff also eliminated companies that had data comparability problems due to major

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<sup>47</sup> Value Line has consistently published information the electric utility industry based on three regions: East, West and Central. The Central Region electric utility industry data is published in Edition 5 of The Value Line Investment Survey data. Staff maintained consistent and comprehensive files for the Central Region for reports published back to 1985, which provides electric utility per share data dating back to 1968.

<sup>48</sup> 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.

1 mergers, acquisitions and/or restructurings. Staff only included companies in which comparable  
2 data was available for each year of the period 1968 through 1999. The companies Staff selected  
3 are shown in Schedules 14-1 through 14-4.

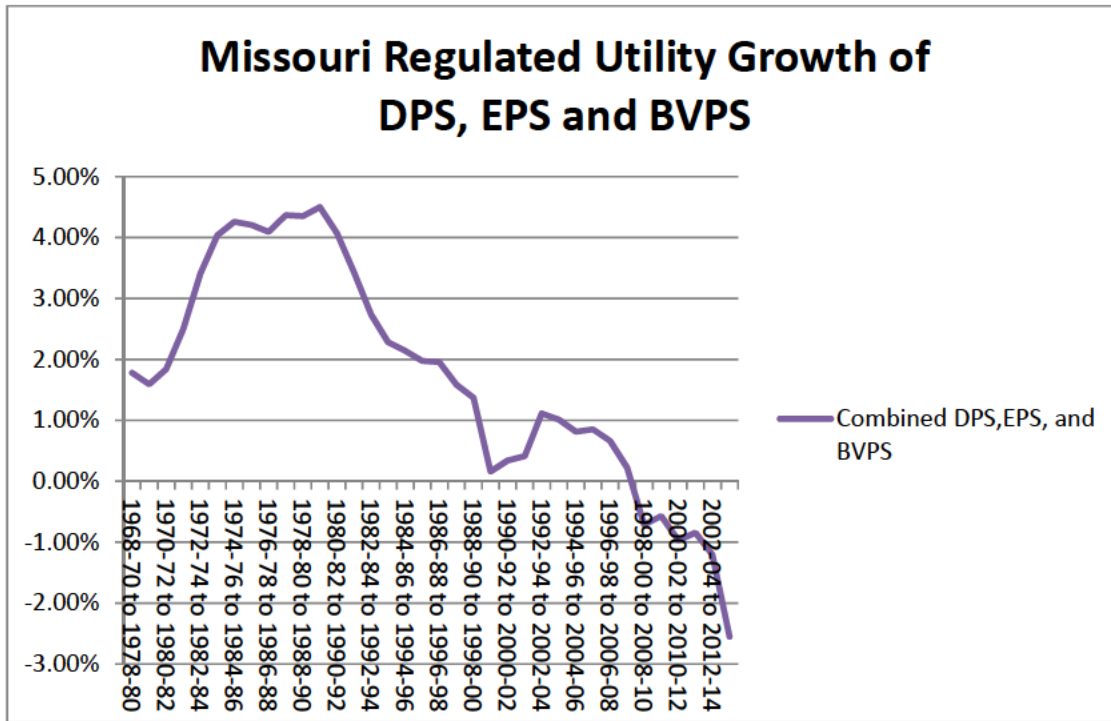
4 Staff's analysis of these electric utility companies' data over the last electric utility  
5 construction cycle indicates that average long-term growth slowly increased through the  
6 late 1980s and early 1990s and declined for the rest of the 1990s. The growth rates are based on  
7 Staff's calculation of a simple average of all of the companies' growth rates over this period.  
8 Because a simple average gives each company equal weight, Staff believes this approach is  
9 appropriate because it does not introduce size bias. As can be seen in the attached Schedules,  
10 the rolling average 10-year compound EPS growth rate for this period was 3.62%; the rolling  
11 10-year compound DPS growth rate was 3.99%; the rolling 10-year compound BVPS growth  
12 rate was 3.18%; and the overall average for DPS, EPS and BVPS was 3.59%.

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

18 Although Staff relied on the aforementioned proxy group for purposes of estimating a  
19 going-forward sustainable industry growth rate, another relevant proxy group to evaluate growth  
20 trends for electric utility companies is the growth of the utility companies that actually have a  
21 large amount of their electric utility operations in Missouri. In addition to evaluating the growth  
22 of Missouri electric utility companies for the period 1968-1999, Staff also evaluated the growth  
23 of Missouri electric utility companies through 2015. As can be seen in the chart below, if the  
24 growth rates of the Missouri utilities are evaluated for the period after the 20<sup>th</sup> century, it is quite  
25 apparent that including this period would reduce the actual realized growth rate:

26  
27  
28  
29  
30  
31 *continued on next page*

1



2

3 The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through  
4 2015 were 1.50%, 1.30% and 2.30%, respectively, with an overall average growth rate of 1.70%.

5 The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through  
6 1999 were 3.59%, 3.00% and 2.57%, respectively, with an overall average growth rate of 3.05%.

7 Consequently, including more recent financial data in evaluating the growth rate trends of  
8 Missouri’s electric utilities actually supports the use of a lower perpetual growth rate than most  
9 ROR witnesses assume for a constant/perpetual growth rate. The above graph certainly would  
10 cause a rational investor to be skeptical of anyone that suggests their investment would  
11 consistently grow at a rate of 5% for any period of time, let alone in perpetuity.

12 Of Missouri’s utilities, The Empire District Electric Company’s business operations have  
13 been the most consistent in being limited to regulated utility operations through the period  
14 analyzed. Although Great Plains Energy has owned some non-regulated operations during the  
15 period Staff analyzed (e.g., Strategic Energy), these operations did not disrupt the financial  
16 performance of the Company to a great extent, even though they did increase Great Plains  
17 Energy’s risk profile. However, Ameren has incurred significant financial problems due to its  
18 ownership of merchant generation operations in Illinois. This exposure caused Ameren to incur  
19 significant losses in recent years, which would skew any financial growth rates that include this

1 information. Although Empire and Great Plains Energy did not incur financial difficulties due to  
2 non-regulated operations, both companies did reduce their dividends in recent years. Because of  
3 these issues that occurred around or after the recession and financial crisis in 2008 and 2009,  
4 Staff also determined the average growth of Missouri's utilities through 2007. The average  
5 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2007 were  
6 2.85%, 2.07% and 2.27%, respectively, with an overall average growth rate of 2.40%.

7 Obviously, the actual experienced growth rates of Missouri's electric utilities support the  
8 reasonable, if not lofty, perpetual growth rates Staff chose to use for its perpetual growth rate  
9 analysis. The actual realized growth rates of Missouri's utilities support a perpetual growth rate  
10 range of 2% to 3% rather than the 3% to 4% Staff assumed. Although these growth rates are  
11 generally characterized as "low" when discussed in the utility ratemaking arena, these growth  
12 rates are more typical of those that are used by investors when determining a reasonable price  
13 to pay for a utility stock.<sup>49</sup> Additionally, considering that the dividend yield from utility stocks  
14 has historically produced 2/3 of the total return on utility stocks,<sup>50</sup> and the fact that dividend  
15 yields for electric utilities are currently approximately 3.8%, a 1.9% capital appreciation rate in  
16 utility stocks is about what investors would expect. This translates into an approximate  
17 expected return of 5.7% for utility stocks, which is quite logical and rational in the current  
18 low-yield environment.

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

20 In order to evaluate the credibility of an estimated perpetual growth rate for the electric  
21 utility industry, it is important to be aware of the changing fundamentals that have occurred and  
22 continue to occur within the electric utility industry due to changes in demand for electricity.  
23 In the past, growth in electric utility earnings and dividends was primarily driven by the increase  
24 in demand for electricity and the growth of customers using electricity. However, this dynamic  
25 has changed and the demand for electricity is no longer a primary growth driver for electric  
26 utilities. The decline in electricity demand growth is illustrated in the graph below:<sup>51</sup>

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<sup>49</sup> Staff has analyzed many utility stock research reports over the last several years and has consistently observed much lower perpetual growth rates than those typically assumed in models for estimating the cost of equity for utility ratemaking.

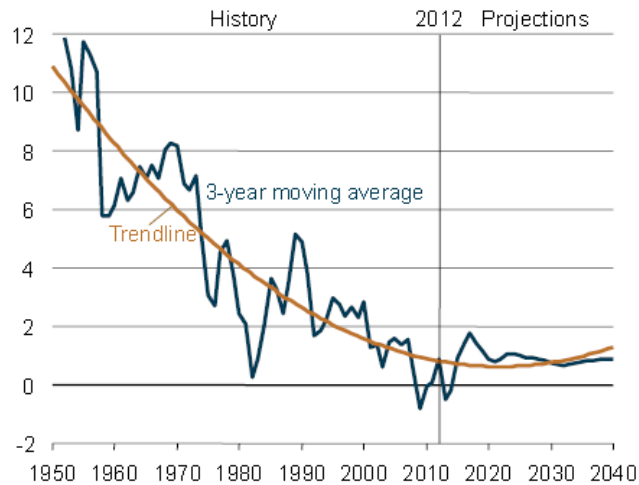
<sup>50</sup> Hugh Wynne, Francois D. Broquin, Saurabh Singh, "U.S. Utilities: Our Dividend Growth Model Identifies Utilities Poised to Pay More," May 20, 2011, Bernstein Research.

<sup>51</sup> Energy Information Administration's *2014 Annual Energy Outlook*, p. MT-16.

## Electricity demand

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

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



2

3 The fact that the growth in electricity demand has been in a steady state of decline seems to  
 4 explain the steady decline in electric utilities' financial performance over the period Staff  
 5 analyzed in its previous discussion in this testimony. To the extent that potential financial  
 6 growth for electric utilities is now limited to the ability to make additional investments and pass  
 7 the cost of these investments (which includes the allowed ROR) onto a near-constant customer  
 8 base, any growth higher than needed capital investment to replace existing infrastructure would  
 9 seem to be highly speculative and not sustainable. However, Staff notes that much of the rate  
 10 base growth for electric utilities in recent years has been due to electric utilities making  
 11 investments in their coal-based generating facilities in order to comply with various emission  
 12 standards. These types of investments are policy-driven, and therefore are not controllable by  
 13 management (although the amount of reasonable project costs are controllable). Absent policy-  
 14 driven investment requirements, it would seem that growth in investment would be limited to a  
 15 rate similar to inflation because the only way to recover these costs is to raise rates on the  
 16 existing customer base that is not using as much electricity.

1 **vi. Preference for GDP Growth**

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

7 Projected GDP growth is available from a variety of sources, such as the Congressional  
8 Budget Office ("CBO"), the Federal Reserve, the EIA, and Blue Chip Economic Forecasts. Staff  
9 will use the CBO, EIA, The Survey of Professional Forecasters published by the Philadelphia  
10 Federal Reserve, The Federal Open Market Committee ("FOMC"), and The Livingston Survey  
11 for purposes of long-term projected GDP growth. The CBO projects an annual compound  
12 growth rate in nominal GDP of approximately 4.10% through 2026<sup>52</sup> EIA's reference case  
13 projects an annual compound growth rate in nominal GDP of approximately 4.24% for the  
14 period 2013 through 2040,<sup>53</sup> The Survey of Professional Forecasters projects a 10-year annual  
15 compound growth rate in real GDP of 2.23%;<sup>54</sup> The Livingston Survey projects an average  
16 annual compound growth rate in real GDP of 2.25% over the next ten years;<sup>55</sup> and the FOMC  
17 projects a central tendency long-term real GDP growth of only 1.8% to 2.2%. In each case in  
18 which the sources do not project a nominal GDP growth rate, Staff recommends adding a GDP  
19 price deflator of 2.0%, which is the CBO's approximate prediction of long-term inflation and  
20 also the inflation rate which is targeted by the Federal Reserve. Based on these projections, the  
21 long-term nominal GDP growth rate is expected to be approximately in the range of 3.84% to  
22 4.3%. These projected long-term growth rates in U.S. GDP are consistent with the current low  
23 interest rate environment, which implies a low growth, low rate of return environment. These  
24 projected GDP growth rates are even lower than what these sources projected just a few months  
25 ago when Staff prepared the Staff Cost of Service Report for the Missouri-American Water  
26 Company rate case, Case No. WR-2015-0301. Staff had determined a projected nominal GDP  
27 growth rate of 4% to 4.5% at the time it prepared its testimony at the end of last year.

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<sup>52</sup> <https://www.cbo.gov/publication/45066>.

<sup>53</sup> <http://www.eia.gov/beta/aeo/#/?id=18-AEO2015&region=0-0&cases=ref2015&start=2015&end=2040&f=A>.

<sup>54</sup> <https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2016/survq116>.

<sup>55</sup> <https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey>.

1 For purposes of quantifying the change in cost of equity from the 2014 cases, Staff will  
2 use the same GDP growth rate, 4.4%, that was used in the 2014 cases. However, as Staff notes  
3 above, recent downward revisions to expected long-term GDP have likely caused investors to  
4 lower their expected growth rates for their utility investments. Consequently, Staff's use of the  
5 4.4% rate in its current analysis will underestimate the change in the cost of equity since 2014.  
6 When using a 4.4% GDP growth rate in Staff's multi-stage DCF results in a COE estimate of  
7 approximately 8.46% for the current proxy group. If Staff had used a 4.1% GDP growth rate, the  
8 multi-stage DCF analysis would imply a COE estimate of 8.23%.

9 **vii. Update of Multi-Stage DCF Analysis on the Proxy Group from**  
10 **the most recent Missouri Electric Utility Rate Cases**

11 Staff updated the multi-stage DCF analysis it performed on the refined proxy group from  
12 the 2014 electric utility rate cases for Ameren Missouri, Empire and KCPL. Staff's multi-stage  
13 DCF analysis for the electric utility industry assumed a perpetual growth rate range of 3% to 4%  
14 based on Staff's compilation and calculation of rolling 10-year compound growth rates for the  
15 electric utility industry for the period 1969 through 1999. Staff used the perpetual growth rate of  
16 4.4% used in the 2014 electric utility rate cases based on the assumption that the electric utility  
17 industry could grow in perpetuity at the same rate as the expected long-term growth rate in the  
18 U.S. economy as measured by GDP. Based on stock prices for the three months through  
19 February 2016, Staff's multi-stage DCF analysis of the 2014 refined electric utility proxy group  
20 indicates a cost of equity of 7.30% to 8.08% using the 3% to 4% terminal growth rates and  
21 8.39% using GDP for a terminal growth rate. At the time Staff had recommended the  
22 Commission reduce Ameren Missouri's allowed ROE by 25 to 75 basis points, the estimated  
23 multi-stage DCF cost of equity for this same proxy group was 7.56% to 8.32% using terminal  
24 growth rates in the range of 3% to 4%. Using GDP for a terminal growth rate, Staff had  
25 estimated the COE for the electric utility industry at 8.63%. These results imply that even when  
26 Staff used the same growth rates from the 2014 rate cases, the implied COE is slightly lower now  
27 than it was in the fall of 2014. Schedule 15 shows detailed comparisons of current implied COE  
28 estimates to implied COE estimates Staff estimated at the time it filed testimony in the Ameren  
29 Missouri, Empire and KCPL 2014 rate cases.

30 Staff believed it was clear at the time of the Ameren Missouri rate case that there was  
31 sufficient evidence to indicate that the COE had declined by 25 to 75 basis points since 2012.



1 In the subsequent Empire and KCPL rate cases, Staff's continually updated analysis indicated  
2 that the cost of equity could be as much as 100 basis points lower than it was in 2012, which  
3 would have justified an allowed ROE of below 9%. However, Staff chose to recommend all of  
4 Missouri's electric utility allowed ROEs be set based on Staff's initial estimate of a 25 to  
5 75-basis point decline.

6 Considering the fact that an update of Staff's multi-stage DCF analysis from the 2014  
7 electric utility rate cases implies that the cost of equity is still below at least the level it was when  
8 Staff performed its analysis in the Ameren Missouri rate case, the current capital and economic  
9 environment supports an allowed ROE consistent with what the Commission considered fair and  
10 reasonable just a few months ago.

## 11 **H. Tests of Reasonableness**

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

### 14 **1. The CAPM**

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

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

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

For inputs, Staff relied on historical capital market return information through the end of 2014. Staff has yet to receive updated capital market return information through 2015, but should be able to provide this information in rebuttal testimony. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending February 29, 2016; that figure was 2.82%. For beta ( $\beta$ ), Staff relied on estimates directly calculated through an Excel spreadsheet designed specifically to be used with the SNL database of market and financial information. Although Staff is no longer using Value Line's published betas for purposes of its CAPM analysis in its direct testimony for electric and gas rate cases, because Value Line is used by many retail investors, Staff still believes Value Line's beta calculation methodology should be considered when performing a CAPM analysis. Because estimating beta is a matter of having access to financial data and performing statistical calculations, unless a financial services provider has a proprietary adjustment they make to their beta calculation, understanding the methodology used by a financial provider allows an analyst to approximately replicate betas of that provider. Fortunately, this is the case for Value Line's beta calculation methodology. Consistent with Value Line's approach to calculating beta, Staff used 5-years of historical weekly returns of the subject company and the New York Stock Exchange ("NYSE") index. The covariance of the weekly returns on the NYSE index and the weekly returns on the subject company is divided by the variance of the weekly returns on the NYSE index to determine raw beta (unadjusted beta). Staff then adjusted the raw beta using the Blume adjustment formula as used by Value Line: Adjusted Beta = (.35 + .67(Unadjusted Beta)) (see Schedule 16).

The average beta for the current proxy group is 0.73. For the market risk premium (Rm – Rf) estimates, Staff relied on the historical difference between earned returns on stocks and earned returns on bonds.<sup>56</sup> The first risk premium was based on the long-term arithmetic

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<sup>56</sup> From Duff & Phelps 2014 *Valuation Handbook: A Guide to the Cost of Capital*.

1 average of historical return differences from 1926-2014 – 6.00 percent. The second risk  
2 premium was based on the long-term geometric average of historical return differences from  
3 1926 to 2014 – 4.40 percent. The results using the long-term arithmetic average risk premium  
4 and the long-term geometric risk premium are 7.22 and 6.05 percent, respectively for the current  
5 proxy group.

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

## 13 **2. Other Tests**

### 14 **a. The “Rule of Thumb”**

15 A “rule of thumb” method allows an objective test of individual analysts’ cost of equity  
16 estimates. Because this method is suggested in a textbook<sup>57</sup> used for the curriculum for  
17 Chartered Financial Analyst (“CFA”) Program, Staff believes this method is free of any bias  
18 from those involved in utility ratemaking. It is also a useful test because it is very  
19 straightforward and limits the risk premium to a 100-basis point range. The cost of equity is  
20 estimated by simply adding a risk premium to the yield-to-maturity (“YTM”) of the subject  
21 company’s long-term debt. Based on experience in the U.S. markets, the typical risk premium is  
22 in the 3% to 4% range. Considering that this is based on general U.S. capital-market experience  
23 and that regulated utilities are on the low end of the risk spectrum of the general U.S. market, a  
24 risk premium closer to 3% seems logical. This is especially true considering that regulated  
25 utility stocks behave like bonds. For the three months ended January 2016, ‘A’ rated long-term  
26 utility bonds and ‘Baa’ rated long-term utility bonds had average yields of 4.34% and 5.54%  
27 respectively.<sup>58</sup> Adding a 3% risk premium, the “rule of thumb” indicates a cost of common

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<sup>57</sup> John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 54.

<sup>58</sup> Mergent Bond Record.

1 equity between 7.34% and 8.54%. Adding a 4% risk premium, the “rule of thumb” indicates a  
2 cost of common equity between 8.34% and 9.54%. According to Value Line’s utility bond yield  
3 data, for the twelve weeks ended February 17, 2016, ‘A’ rated long-term utility bonds and ‘Baa’  
4 rated long-term utility bonds had average yields of approximately 4.27% and 4.80%  
5 respectively.<sup>59</sup> Adding a 3% risk premium, the “rule of thumb” indicates a cost of common  
6 equity between 7.27% and 7.80%. Adding a 4% risk premium, the “rule of thumb” indicates a  
7 cost of common equity between 8.27% and 8.80%.

#### 8 **b. Average Authorized Returns**

9 In the past, the Commission has applied a test of reasonableness using average  
10 authorized returns published by Regulatory Research Associates (“RRA”) to test the  
11 reasonableness of its allowed ROE. According to RRA, the average authorized return on equity  
12 authorized electric utilities was 9.85% in 2015 (based on 30 ROE determinations), compared to a  
13 2014 calendar year average of 9.91% (based on 38 ROE determinations).<sup>60</sup> Excluding the effect  
14 of the surcharge/rider generation cases in Virginia, the average allowed electric ROEs were  
15 9.58% for the 2015 calendar year and 9.76% for the 2014 calendar year.

16 In order to provide more specific information on the allowed ROE’s by type of electric  
17 utility operations, Staff determined the allowed ROEs that were given to integrated electric  
18 utility companies. Staff excluded allowed ROEs that were determined for dockets not involving  
19 a full general rate case (i.e. rider only cases). Staff also continued to exclude the aforementioned  
20 Virginia rate cases. The average allowed ROE for integrated electric utilities was 9.75 % for the  
21 2015 calendar year and 9.94 % for the 2014 calendar year.

22 As a further refinement, Staff also evaluated allowed ROE information for only cases that  
23 were fully-litigated as in these cases, one would expect that each issue is determined based on its  
24 own merits. Allowed returns determined in the context of a settled case are not as reliable  
25 because parties make adjustments to other elements of the ratemaking formula in order to arrive  
26 at an overall reasonable number. It has been Staff’s experience that some companies do not want

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<sup>59</sup> Value Line Selection & Opinion December 11, 2015 through February 26, 2016, except for the February 5, 2016 Selection & Opinion because it was unavailable to Staff at the time of testimony.

<sup>60</sup> RRA, Regulatory Focus – Major rate case decisions - -Calendar 2015 - January 14, 2016: 2015 data includes five surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects.

1 a lower ROE published in a settlement because this is a headline number. Consequently,  
2 companies may compromise on a more obscure area of the rate case in order to have a higher  
3 ROE published in the settlement. Allowed ROEs for fully-litigated cases were 9.74 % for the  
4 2015 calendar year, and 10.03 % for the 2014 calendar year.

5 The allowed ROE information provides a trend that the average allowed ROEs for  
6 electric utilities have decreased since 2014.

## 7 **I. Conclusion**

8 A just and reasonable rate is one that is fair to the investors and fair to the ratepayers.  
9 Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to  
10 the shareholders. Fairness to the shareholders means rates that will produce revenues, on an  
11 annual basis, sufficient to cover Empire's prudent cost of service, which includes an allowed  
12 ROR. Considering all of the information that Staff has reviewed, there does not appear to be a  
13 significant change in the capital markets to support a conclusion that the cost of equity for the  
14 electric utility industry has substantially increased or decreased since the Commission ordered an  
15 allowed ROE of 9.53% for Ameren Missouri and 9.50% for KCPL. Consequently, Staff  
16 recommends the Commission authorize an ROE for Empire in the range of 9.50 percent to 10.00  
17 percent, with a midpoint of 9.75 percent. Staff's midpoint recommended ROE of 9.75% for  
18 Empire is approximately 25 basis points higher than the recent allowed ROEs for Ameren  
19 Missouri and KCPL because Staff added 25 basis points due to Empire's lower credit rating,  
20 which is based on the business and financial risks of Empire's regulated utility operations.  
21 Ameren and KCPL have corporate credit ratings of 'BBB+' while Empire has a corporate credit  
22 rating of 'BBB'.<sup>61</sup> The spreads between 'A' rated utility bonds and 'BBB'/'Baa' rated utility  
23 bonds have historically averaged approximately 45 basis points.<sup>62</sup> This spread would  
24 normally suggest a 15-basis point risk premium is acceptable for a company rated one notch  
25 lower ( $45/3 = 15$ ). As mentioned earlier, Staff noticed from the Mergent Bond Record that  
26 spreads between 'A' rated and 'BBB'/'Baa' utility bond yield have recently significantly  
27 increased to over double the historical average. Staff's analysis using Mergent's utility bond  
28 yield constituent list (excluding the energy companies) and FINRA data for the twelve weeks

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<sup>61</sup> S&P Ratings as of March 7, 2016. Ameren Corp. and Great Plains Energy.

<sup>62</sup> Mergent Bond Record.

1 ended March 14, 2016, showed a spread of approximately 65 basis points between ‘A’ rated and  
2 ‘BBB’/‘Baa’ rated utility bonds. This spread would suggest approximately a 22-basis point risk  
3 premium is acceptable for a company rated one notch lower ( $65/3 = 21.67$ ). Therefore, because  
4 of the recent increase in spreads between ‘A’ and ‘BBB’/‘Baa’ rated utility bonds, Staff  
5 recommends a 25-basis point adjustment

6 Using an allowed ROE range of 9.50% to 10.00% for Empire results in an allowed rate of  
7 return range of 7.36 percent to 7.61 percent (*see* Schedule 18). Using the point recommended  
8 allowed ROE of 9.75% results in an allowed rate of return of 7.49%. This was calculated by  
9 applying an embedded cost of long-term debt of 5.33% and an allowed return on common equity  
10 range of 9.50% to 10.00%, with a midpoint of 9.75%, to a capital structure consisting of 48.73%  
11 common equity and 51.27% long-term debt. Because there appears to be some concern in  
12 setting an allowed return on equity based on a reasonable estimate of the cost of equity, Staff  
13 recommends the Commission set the allowed ROE at 9.75% in this case. Although this is above  
14 what Staff estimates to be the cost of equity to be in the current capital market environment, this  
15 allowed ROE is fair and reasonable considering the recent allowed ROEs the Commission  
16 authorized Ameren Missouri and KCPL.

17  
18 *Staff Expert/Witness: Shana Griffin*

## 19 **VIII. Rate Base**

### 20 **A. Plant in Service**

#### 21 **1. Plant in Service updated as of September 30, 2015**

22 Accounting Schedule 3, Plant in Service, reflects the rate base value of Empire’s plant in  
23 service by account, updated through September 30, 2015, to be later trued-up through March 31,  
24 2016.

25  
26 *Staff Expert/Witness: Jennifer K. Grisham*

#### 27 **2. Plant Adjustments: Allocation to Gas**

28 Empire records its natural gas general plant in-service balances entirely on its electric  
29 books. To ensure that Empire’s electric customers only pay in rates for costs associated with

1 electric service, Staff adjusted Empire’s plant balances to remove the portion of the Company’s  
2 general plant associated with Empire’s natural gas business for rate case purposes.

3  
4 *Staff Expert/Witness: Jennifer K. Grisham*

## 5 **B. Depreciation Reserve**

### 6 **1. Depreciation Reserve as of September 30, 2015**

7 Accounting Schedule 6, Depreciation Reserve, reflects the rate base value of Empire’s  
8 depreciation reserve by account, updated through September 30, 2015, to be trued-up through  
9 March 31, 2016.

10  
11 *Staff Expert/Witness: Jennifer K. Grisham*

### 12 **2. Reserve Adjustments: Allocation to Gas**

13 Empire records its natural gas depreciation reserve associated with general plant entirely  
14 on its electric books. So that Empire’s electric customers only pay in rates for the costs to  
15 provide them electric service, Staff removed the portion of the general plant depreciation reserve  
16 associated with Empire’s natural gas business for rate case purposes.

17  
18 *Staff Expert/Witness: Jennifer K. Grisham*

### 19 **3. Plant & Depreciation Reserve Adjustments: Capitalized Incentive** 20 **Compensation**

21 On an ongoing basis, Empire capitalizes to plant in service a portion of its  
22 incentive compensation for the Employee Stock Purchase Plan and the Bonus Incentive Plan  
23 (“Lightning Bolts”). Staff made regulatory adjustments to the plant in service and depreciation  
24 reserve from June 30, 2012, through September 30, 2015, the end of the update period in this  
25 case, in order to eliminate these amounts from cost of service, consistent with prior Staff policy.  
26 Since Staff removed these compensation expenses from its cost of service income statement  
27 (*see* Section X. F. 2.b.), Staff is also making an adjustment to remove these costs from rate base  
28 in this case.

29  
30 *Staff Expert/Witness: Jermaine Green*

1           **C. Cash Working Capital (“CWC”)**

2           The cash working capital requirements in the Company’s rate base have been updated  
3 from the previous rate case, No. ER-2014-0351. Staff is using the same revenue and expense  
4 lags that were agreed to by the Company and Staff in the last case, but it has updated the adjusted  
5 test year amounts associated with each CWC Accounting Schedule line item.

6  
7 *Staff Expert/Witness: Jennifer K. Grisham*

8           **D. Prepayments and Materials and Supplies**

9           The Company has utilized shareholder funds to finance prepaid items such as insurance  
10 premiums and postage. The Company is reimbursed by customers for these costs once the items  
11 are charged to expense during a subsequent period. The Staff has included these prepayments in  
12 rate base at the 13-month average level, ending September 2015. There were three prepayment  
13 accounts that were excluded in the Staff’s average: Working Funds Iatan (165350), Working  
14 Funds Plum Point (165351), and KCPL Land Lease (165352). These are cash accounts, not  
15 actual investment in utility assets, and are therefore excluded from rate base.

16           The Company also holds a variety of materials and supplies (“M&S”) in inventory so  
17 the items can be readily available when needed in performing its utility operations.  
18 Staff performed an analysis of all of Empire’s M&S accounts from August 2013 through  
19 September 2015. For most accounts, there was no upward or downward trend noted. As a  
20 result, the 13-month average of Empire’s M&S account balances as of September 30, 2015, the  
21 end of the Staff’s update period in this case, was used to determine the average balance for these  
22 accounts. There were six M&S accounts (154100, 163025, 163081, 163086, 163316, and  
23 163327) which showed a steady trend, either upward or downward, depending on the account,  
24 within the review period. Accordingly, Staff used the most current ending balance as a more  
25 appropriate number for these six accounts.

26           Empire’s electric and water inventory is included on Empire’s electric books and records;  
27 therefore, an adjustment entry has to be made to eliminate the water M&S from Empire’s electric  
28 books. Staff used a 13-month average of Empire’s water inventory to determine the level of  
29 M&S inventory that needed to be eliminated from Empire’s rate base in this proceeding.

30  
31 *Staff Expert/Witness: Jennifer K. Grisham*



1           **E. Fuel Inventories**

2           **Coal Inventory** - Staff used the results of its fuel model to calculate the annual amount  
3 of coal used by each Empire generating plant to meet its total company normalized native load.  
4 Empire operates in four retail jurisdictions: Missouri, Arkansas, Kansas, and Oklahoma.  
5 “Native load” is the kilowatt or megawatt demand placed upon Empire’s electric system by its  
6 regulated retail electric customers. To determine the amount of coal inventory, the average daily  
7 burn by unit must be calculated. The average daily burn by unit is derived by dividing the  
8 annualized tons burned by the difference between 365 days and the number of annual  
9 planned outage days. Then, the average daily burn is multiplied by an appropriate number  
10 of days of inventory for each plant resulting in a burn inventory. The number of days of  
11 inventory of Powder River Basin (“PRB”), or “western” coal, for the Asbury 1 unit is set by  
12 Empire at or around 60 days. The PRB coal in 2016 will be supplied by western coal suppliers:  
13 Peabody Coal Sales, Arch Coal Sales, and Cloud Peak Energy.

14           Empire also normally carries an inventory of local (Illinois) bituminous coal supplied by  
15 Foresight Coal Sales, under contract; the days of inventory included for this coal is also 60 days.  
16 Staff has also used a 60-day calculation to establish Empire’s rate base investment in  
17 the coal inventory maintained both at KCPL’s Iatan Generating Stations (Empire is a 12% owner  
18 of Iatan 1 and 2) and Plum Point Energy Associates, LLC’s Plum Point Energy Station (Empire  
19 is a 7.52% owner of Plum Point).

20           Staff multiplied the resulting burn inventory for each unit by the delivered cost of coal  
21 per ton for that unit as calculated by Staff. To this total, Staff then added the fixed cost of  
22 basemat coal established in the prior Empire Rate Case No. ER-2011-0004 for each unit, except  
23 for Plum Point. The basemat for the Plum Point unit is capitalized as part of plant in service  
24 costs. Basemat coal is the bottom portion of a coal pile that is not usable as fuel due to  
25 contamination by soil, clay, and other contaminants. The total cost of the burn inventory and  
26 basemat was multiplied by Staff’s energy jurisdictional factor to arrive at the Missouri allocated  
27 amount with the result being the amount that is reflected as part of Fuel Inventories in  
28 Accounting Schedule 2, Rate Base.

29           **Fuel Oil Inventory** - Staff used the 13-month average inventory quantities and a  
30 weighted average price for oil inventory levels as reported in the Company’s Coal and Oil  
31 Inventory Reports provided in response to Staff’s Data Request No. 0022.

1           **Gas Stored Underground** – According to Empire, the Company is not renewing its  
2 natural gas storage agreement with Southern Star Central Gas Pipeline, Inc. (“SSCGP”) when it  
3 expires on March 31, 2016. After that time, Empire will no longer be storing any natural gas  
4 underground. Therefore, Staff did not include any inventory cost for Gas Stored Underground in  
5 rate base.

6  
7 *Staff Expert/Witness: Keith D. Foster*

#### 8           **F. Amortization of Electric Plant**

9           Staff has adjusted the amortization reserve for electric plant intangible assets to reflect  
10 the updated balances through September 30, 2015, the end of the update period for this case.  
11 The amortization reserve balance as of September 30, 2015, is \$12,739,926 and was included as  
12 an offset to rate base in Staff’s Accounting Schedules.

13  
14 *Staff Expert/Witness: Jennifer K. Grisham*

#### 15           **G. Amortization of PeopleSoft Intangible Asset**

16           Staff has adjusted the intangible asset for the PeopleSoft software costs to reflect the  
17 updated balances through September 30, 2015. The regulatory asset balance, as of the end of the  
18 update period September 30, 2015, is \$197,209 and was included as an addition to rate base in  
19 Staff’s Accounting Schedules.

20  
21 *Staff Expert/Witness: Jennifer K. Grisham*

#### 22           **H. Customer Deposits**

23           The amount of customer deposits shown on Accounting Schedule 2, Rate Base,  
24 represents a 13-month average (September 2014 - September 2015) of Empire’s customer  
25 deposits. Customer deposits are funds received from customers as security against potential  
26 loss arising from failure to pay for utility service. Staff included a representative ongoing level  
27 of \$10,892,877 as an offset to rate base.

1 Interest on customer deposits is also included in the Company's rates because customers  
2 should receive a reasonable rate of return on their deposits until the monies are refunded to them.  
3 The appropriate amount of interest to include in the Company's expenses can be determined by  
4 review of the applicable sections of Empire's current filed tariff. The tariff (Section 3, Page 5)  
5 states that the "interest rate paid upon return of a deposit, per annum, compounded annually shall  
6 be equal to the prime rate published in the Wall Street Journal as being in effect on the last  
7 business day of December of the prior year plus 1%." The prime rate in effect as of  
8 December 31, 2014, was 3.25%. One percent was added to this rate for a total of 4.25% interest  
9 rate on customer deposits. The amount of interest on customer deposits, \$462,947, is included in  
10 Staff Accounting Schedule 10, Adjustments to the Income Statement.

11  
12 *Staff Expert/Witness: Jennifer K. Grisham*

### 13 **I. Customer Advances**

14 Customer advances are funds provided to Empire by individual customers of the  
15 Company to assist in recovering the costs of electric plant construction projects specific to the  
16 customers under certain circumstances. Unlike customer deposits, no interest is paid to  
17 customers for the use of this money. Therefore, it is appropriate to include these funds as an  
18 offset to rate base. There has been a significant decrease in the balance of this account since the  
19 last rate case. The ending balance as of September 30, 2015, the end of the Staff's update period  
20 in this case, is shown on Accounting Schedule 2, Rate Base.

21  
22 *Staff Expert/Witness: Jennifer K. Grisham*

### 23 **J. Accumulated Deferred Income Taxes ("ADIT")**

24 Empire's ADIT represents, in effect, a net prepayment of income taxes by customers prior  
25 to tax payment by Empire. For example, because Empire is allowed to deduct depreciation  
26 expense on an accelerated basis for income tax purposes, the amount of depreciation expense  
27 used as a deduction for income taxes purposes by Empire is considerably higher than the amount  
28 of depreciation expense used for ratemaking purposes. This results in what is referred to as a  
29 "book-tax timing difference," and creates a deferral of income tax reserves to the future. The net

1 credit balance in the ADIT accounts reserve represents a source of cost-free funds to Empire.  
2 Therefore, Empire’s rate base is reduced by the ADIT balance to avoid having customers pay a  
3 return on funds that are provided cost-free to the Company. Generally, deferred income taxes  
4 associated with all book-tax timing differences created through the ratemaking process should be  
5 reflected in rate base. Staff has decided to take this approach in calculating the ADIT rate base  
6 offset amount in this case.

7 The deferred tax impact associated with the following past tax timing differences were  
8 included in Staff’s rate base offset: Accelerated Depreciation, Loss on Hedge Transactions,  
9 Gain on Hedge Transactions, License Software Amortization, Loss on Reacquired Debt,  
10 Ice Storm Expenses, Deferred Federal Tax Asset-Miscellaneous, Deferred Tax Liability-Iatan  
11 Deferred Charges, Deferred Tax-ITC Tax Basis-Iatan, Contributions in Aid of Construction,  
12 Post-retirement Benefits – Pensions and Capitalized Interest.

13 In December 2015, the U.S. Congress passed a “tax extender” package which includes an  
14 extension of the availability of bonus depreciation benefits through the end of 2014. Bonus  
15 depreciation allows the utility to deduct capital investments more quickly than under normal  
16 accelerated tax depreciation allowances. The bonus depreciation benefit was scheduled to expire  
17 at the end of 2014 but was again extended in December 2015. Staff’s direct case reflects the tax  
18 impacts of bonus depreciation on Empire’s accumulated deferred income tax rate base off-set  
19 amount.

20  
21 *Staff Expert/Witness: Amanda C. McMellen*

## 22 **K. Vegetation Management Tracker Regulatory Asset**

23 The tracker amount for this case is \$2,870,695, calculated as the difference between the  
24 vegetation management costs and Empire’s rate recoveries of vegetation management costs from  
25 September 30, 2014, to July 31, 2015. Staff included these amounts in its rate base. Staff’s  
26 recommendation does not include any carrying costs for the current Empire vegetation  
27 management tracker balance.

28  
29 *Staff Expert/Witness: Jermaine Green*

1                   **L. Iatan and Plum Point Carrying Costs**

2                   **1. Iatan 1**

3                   Pursuant to Empire’s regulatory plan approved by the Commission in Case No. EO-2005-  
4 0263, Empire deferred certain “carrying costs” associated with the Iatan 1 AQCS investment past  
5 its in-service date into Account 182308, Iatan Deferred Carrying Costs. (The deferral of carrying  
6 costs after a project’s in-service date is also known as “construction accounting”). In the  
7 *Report and Order* in KCPL’s Case No. ER-2010-0355, the Commission disallowed certain costs  
8 that had been booked to the Iatan accounts. The effect of these disallowances reduces the  
9 balance of the Iatan 1 AQCS plant balance. In Empire’s Case No. ER-2012-0345, Staff removed  
10 any construction accounting allowances associated with the portion of Iatan 1 AQCS approved  
11 disallowances that were allocated to Empire from its rate base and expense amortization  
12 calculations. In Empire’s most recent rate case, Case No. ER-2014-0351, Staff used the balance  
13 in Account 182308 as of June 30, 2012, and the annual amortization expense included in Staff’s  
14 Accounting Schedules in Case No. ER-2012-0345, to determine the unamortized balance as of  
15 August 31, 2014, for this item to include in rate base. For the current rate case, Staff calculated  
16 the remaining unamortized balance as of September 30, 2015, to include in rate base.

17 *Staff Expert/Witness: Keith D. Foster*

19                   **2. Iatan 2**

20                   Pursuant to Empire’s regulatory plan approved by the Commission in Case No.  
21 EO-2005-0263, Empire deferred certain “carrying costs” associated with the Iatan 2 generating  
22 unit investment past its in-service date into Account 182332, MO IatanII Df Chg ER-2010-0130.  
23 In the *Report and Order* in KCPL’s Case No. ER-2010-0355, the Commission disallowed certain  
24 costs that had been booked to the Iatan accounts. Staff has removed any construction accounting  
25 allowances associated with the portion of Iatan 2 disallowances that were allocated to Empire  
26 from its rate base and expense amortization calculations. The balance of Iatan 2 carrying costs  
27 was also reduced by Empire’s deferral of fuel and purchased power expense savings it has  
28 incurred due to the addition of Iatan 2 to its generating system from the unit’s in-service date  
29 through June 30, 2012. In Empire’s most recent Case No. ER-2014-0351, Staff used the balance  
30 in Account 182332 as of June 30, 2012, and the annual amortization expense included in Staff’s

1 Accounting Schedules in Case No. ER-2012-0345 to determine the unamortized balance as of  
2 August 31, 2014, for this item to include in rate base. For the current rate case, Staff calculated  
3 the remaining unamortized balance as of September 30, 2015, to include in rate base.

4  
5 *Staff Expert/Witness: Keith D. Foster*

### 6 **3. Plum Point**

7 Pursuant to Commission approval of the *Non-Unanimous Stipulation and Agreement and*  
8 *Joint Proposal Regarding Certain Procedural Matters* dated February 25, 2010, in Case No.  
9 ER-2010-0130, Empire deferred certain “carrying costs” associated with the Plum Point  
10 generating unit investment past its in-service date into Account 182331, MO PlumPt Df Chgs  
11 ER-2010-0130. Based on the results of its Construction Audit and Prudence Review for  
12 Plum Point (submitted in Case No. ER-2011-0004), Staff recommended one disallowance to  
13 Empire’s Plum Point plant balances. In Empire’s most recent Case No. ER-2014-0351, Staff  
14 used the balance in Account 182331 as of June 30, 2012, and the annual amortization expense  
15 included in Staff’s Accounting Schedules in Case No. ER-2012-0345 to determine the  
16 unamortized balance as of August 31, 2014, for this item to include in rate base. For the current  
17 rate case, Staff calculated the remaining unamortized balance as of September 30, 2015, to  
18 include in rate base.

19  
20 *Staff Expert/Witness: Keith D. Foster*

### 21 **4. Iatan Carrying Costs Amortization**

22 Pursuant to earlier agreements, Empire deferred certain carrying costs (monthly debt and  
23 equity-derived carrying charges) and monthly depreciation for its Iatan 1 AQCS Account 182308  
24 - Iatan Deferred Carrying Costs, Iatan 2 Account 182332 - MO IatanII Df Chg ER-2010-0130,  
25 and Plum Point Account 182331 - MO PlumPt Df Chgs ER-2010-0130. This deferral of carrying  
26 costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments was authorized under previous  
27 agreements, approved by the Commission. In Empire’s Case No. ER-2012-0345, Staff  
28 recommended amortization of these carrying costs into cost of service using a composite  
29 amortization rate derived from dividing the total depreciation expense for each plant by the total

1 plant balance for each plant. Staff used these composite rates and calculated amortization  
2 amounts of \$84,729 for Iatan 1 AQCS, \$44,828 for Iatan 2, and \$1,987 for Plum Point. Staff  
3 used the same amortization amounts in this case.

4  
5 *Staff Expert/Witness: Keith D. Foster*

## 6 **5. Southwestern Power Administration (“SWPA”) Hydro Reimbursement**

7 On September 16, 2010, Empire received a payment in the amount of \$26,563,700 from  
8 the Southwestern Power Administration (“SWPA”), to compensate Empire for the expected  
9 financial impact of a future reduction in capacity at its Ozark Beach hydroelectric plant.  
10 The reduction in capacity at Ozark Beach is due to the Energy and Water Development Act of  
11 2006, federal legislation which requires a decrease in available head waters at Ozark Beach.  
12 In Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to the customers  
13 over a ten-year period via a tracker mechanism. Staff has included as an offset to rate base the  
14 unamortized balance of this regulatory liability.

15  
16 *Staff Expert/Witness: Amanda C. McMellen*

## 17 **IX. Allocations**

### 18 **A. Corporate Allocations**

19 As discussed earlier in this Report, Empire is engaged in both regulated and  
20 non-regulated business operations. Staff reviewed Empire’s methods for assigning and  
21 allocating costs to its regulated electric, gas, and water operations, as well as to its various  
22 non-regulated operations. Under Empire’s corporate cost allocation system, costs are either  
23 directly assigned by Empire to business units (Empire refers to this assignment as  
24 “direct billing”), indirectly allocated to the business units, or allocated through use of a general  
25 allocation factor.

26 Under the direct assignment approach, Empire directly assigns certain costs to its  
27 regulated electric operations either by use of vendor invoices or by labor charges. In the case of  
28 assignment by vendor invoice, each vendor invoice that includes charges for goods and services  
29 that directly benefit a specific business unit has the invoiced costs directly assigned to the

1 appropriate corresponding business unit. In the case of assignment by labor, all employees are  
2 required to record their time electronically based on the amount of time each employee spends  
3 each month working for each business unit. The system then allocates a portion of that  
4 employee's salary, including associated payroll taxes and fringe benefits, to the appropriate  
5 business unit. However, Staff has concerns with the reliability of Empire's time reporting; for  
6 example, Staff did not find any indication that any employee time was recorded or allocated to  
7 Empire's recent strategic alternatives or acquisition activities. In addition, Staff noticed that  
8 certain employees did not record any time to non-regulated operations. Staff has proposed an  
9 adjustment to account for these non-recorded allocations, which is described in Section X. I. 24.

10 Empire's indirect allocation factor is based upon a "unit of service method," which is  
11 employed by the Company in the event that incurred costs cannot be directly billed to the  
12 individual business units as described above. Empire uses the unit service method based on  
13 certain unit drivers. Examples of Empire's unit drivers are as follows: number of vouchers,  
14 number of active customers, number of purchase orders, and number of personal computers. An  
15 allocation rate is then calculated based on information obtained from various general ledger  
16 entries and adjusted periodically.

17 For costs that cannot be directly assigned, or that have no unit drivers, the Company uses  
18 a General Corporate Allocator it refers to as a "Modified Massachusetts Formula."  
19 A "Massachusetts Formula" is a general allocation factor based upon three (3) separate  
20 measurements of directly assigned costs, and which is used to allocate a company's common  
21 costs that cannot be reasonably directly assigned or indirectly allocated to a company's business  
22 units. The "Modified Massachusetts Formula" used by Empire consists of the averages of  
23 (1) profit margin, (2) payroll, and (3) net property, plant, and equipment. Staff modified some of  
24 the various allocation factors to reflect Staff's adjusted numbers that were included in its cost of  
25 service. Please reference Staff's Exhibit Modeling System ("EMS") that was filed with its cost  
26 of service report in this case for the allocation factors used by Staff.

27 Staff has further concerns regarding Empire's allocation methodologies. For one, it  
28 appears that Empire may not properly assign a portion of its common costs to its water and  
29 non-regulated operations. Such a methodology would overstate the costs to provide  
30 electric service while understating the cost to provide water service and non-regulated  
31 operations. Staff has proposed an adjustment to account for these common costs, which is



1 described in Section X. I. 24. Other issues of concern that bear further investigation at a future  
2 date include: (1) whether or not common costs are excluded from base amounts when  
3 determining common cost allocation percentages; (2) whether or not there are any outside  
4 services charges that should be allocated across Empire’s businesses as a common cost; and  
5 (3) whether or not Empire’s application of the “Modified Massachusetts Formula” over-allocates  
6 costs to its electric business. This is not an all-inclusive list. Staff reserves the right to identify  
7 any additional issues as we do further investigation.

8  
9 *Staff Expert/Witness: Keith D. Foster*

## 10 **B. Jurisdictional Allocation Factors**

11 Jurisdictional allocation factors are used to allocate demand-related and energy-related  
12 costs to the applicable jurisdictions. Fixed costs, such as the capital costs associated with  
13 generation and transmission plant, are allocated on the basis of demand. Variable costs, such  
14 as fuel, are more appropriately allocated on the basis of energy consumption. In this case,  
15 demand-related and energy-related costs are divided among three jurisdictions: Missouri Retail  
16 Operations, Non-Missouri Retail Operations and Wholesale Operations. The particular allocation  
17 factor applied is dependent upon the type of cost that is being allocated.

### 18 **1. Demand Allocation Factor**

19 Demand refers to the rate at which electric energy is delivered to a system to match  
20 the requirements of its customers (“load”), generally expressed in kilowatts (“kW”) or  
21 megawatts (“MW”), either at an instant in time or averaged over a specified time interval.  
22 System peak demand is the largest electric requirement (“load”) that occurs within a specified  
23 period of time, (e.g. hour, day, month, season and year) on a utility’s system. Since generation  
24 units and transmission lines are planned, designed, and constructed to meet a utility’s anticipated  
25 system peak demands, plus required reserves, the contribution of each of Empire’s three  
26 jurisdictions: Missouri Retail Operations, Non-Missouri Retail Operations and Wholesale  
27 Operations, coincident to the system peak demand, *i.e.*, each jurisdiction’s demand at the time of  
28 the system peak, is the appropriate basis on which to allocate these facilities. Thus, the term  
29 coincident peak (“CP”) refers to the load, generally in kW or MWs, in each of the jurisdictions

1 that coincides with Empire’s overall system peak recorded for the time period in the  
2 corresponding analysis. Staff is utilizing a Twelve Coincident Peak (“12 CP”) methodology to  
3 determine demand allocation factors for Empire. Staff determined the demand allocation factor  
4 for each jurisdiction using the following process:

- 5 a. Identify Empire’s peak hourly load in each month for the time period  
6 October 2014 through September 2015 and sum the hourly peak loads.
- 7 b. Sum the particular jurisdiction’s corresponding loads for the hours  
8 identified in a. above.
- 9 c. Divide b. by a. above.

10 The result is the allocation factor for each jurisdiction:

11	Retail Operations:	
12	Missouri -	.8372
13	Non – Missouri -	.1077
14	Wholesale Operations:	.0551

15 **2. 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 individual jurisdiction, is the ratio of the  
18 normalized annual kilowatt-hour (“kWh”) usage of each particular jurisdiction to the total  
19 normalized Empire kWh usage. The kWh usage data includes adjustments for anticipated  
20 growth, annualizations, and non-normal weather. Staff witnesses Ashley R. Sarver and  
21 Robin Kliethermes, respectively, provided the growth and annualization adjustments. Staff  
22 witness Seoung Joun Won provided the weather and days adjustments. Staff has calculated the  
23 following energy allocation factors for the particular jurisdictions, utilizing the twelve month  
24 period ending August 2014:

25	Retail Operations:	
26	Missouri -	.8238
27	Non – Missouri -	.1105
28	Wholesale Operations -	.0657

1 Staff witness Keith D. Foster used these demand and energy jurisdictional allocation factors in  
2 determining Staff's cost of service for Empire in this case.

3  
4 *Staff Expert/Witness: Alan J. Bax*

## 5 **X. Income Statement**

### 6 **A. Rate Revenues**

#### 7 **1. Introduction**

8 Since the largest component of operating revenues results from rates charged to Empire's  
9 Missouri retail customers, a comparison of operating revenues with cost of service is  
10 fundamentally a test of the adequacy of the currently effective Missouri jurisdictional retail  
11 electricity rates. If the overall cost of providing service to Missouri retail customers exceeds  
12 operating revenues, an increase in the current rates that Empire charges to Missouri retail  
13 customers for electricity is appropriate.

14 One of the major tasks in a rate case is not only to determine whether a deficiency  
15 (or excess) between cost of service and operating revenues exists, but also to determine the  
16 magnitude of any such deficiency (or excess). Any deficiency (or excess) identified can only be  
17 made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenues)  
18 prospectively, on a going-forward basis.

19  
20 *Staff Expert/Witness: Ashley R. Sarver*

#### 21 **2. Definitions**

22 Operating Revenues are composed of Retail Rate Revenue and Other Operating Revenue.  
23 Each is defined respectively as follows:

24 **Retail Rate Revenue:** Test year rate revenues consist solely of the revenues derived  
25 from the current rates Empire charges for providing electric service to its Missouri retail  
26 customers (i.e., native load and customer charges). Empire's charges are determined by  
27 multiplying each customer's usage by the per unit rates established in its tariff. Empire's tariff  
28 provides that different rates apply to different types of charges (demand vs. energy) and different  
29 times of the year (summer vs. winter); and to customers in different rate classes (differentiation

1 by type and amount of use). Revenues from the Fuel Adjustment Clause (“FAC”) represent  
2 collections or refunds of prior period fuel costs and are excluded in determining the annualized  
3 level of ongoing rate revenues.

4 **Other Operating Revenue:** This category includes revenues from such items as  
5 forfeited discounts, reconnect charges, rent from electric property, and other  
6 miscellaneous charges.

7  
8 *Staff Expert/Witness: Ashley R. Sarver*

### 9 **3. The Development of Rate Revenue in this Case**

10 The objective of this section is to determine normalized and annualized test year usage  
11 and revenues by rate class. The intent of Staff’s adjustments to test year Missouri usage and rate  
12 revenues is to determine the level of revenue that the Company would have collected on an  
13 annual, normal-weather basis, based on information “known and measurable” at the end of the  
14 update period.

15 The two major categories of revenue adjustments are known as “normalization” and  
16 “annualization.” Normalization adjustments eliminate the impact from revenues of test year  
17 events that are unusual and unlikely to be repeated in the years when the new rates from this case  
18 are in effect. To eliminate the impact of test year weather on revenues is an example of a  
19 normalization adjustment. Annualizations are adjustments that re-state test year results as if  
20 conditions known at the end of the update period had existed throughout the entire test year.  
21 Adjustment for customer growth is an example of an annualization.

22  
23 *Staff Expert/Witness: Ashley R. Sarver*

### 24 **4. Regulatory Adjustments to Update Period Usage and Rate Revenue**

#### 25 **a. Update Period Adjustment**

26 For purposes of this case, Empire used Staff’s EMS run filed March 26, 2015, in  
27 Empire’s last rate case, Case No. ER-2014-0351, as a starting point for any usage and revenue  
28 adjustments. Empire then updated usage and corresponding revenues for changes in customer  
29 growth and the rate increase that took effect on July 26, 2015. Although Staff will also use the  
30 retail revenues from Staff’s EMS run filed March 26, 2015, as a starting point, Staff will update

1 the retail revenues and usage for changes in normalized and annualized sales through the end of  
2 September 30, 2015, to provide a more current basis for the revenue calculation.

3  
4 *Staff Expert/Witness: Robin Kliethermes*

#### 5 **b. Weather Variables**

6 This information was provided to Staff witness Seoung Joun Won for weather  
7 normalization of the update period kWh usage and hourly loads. Each year's weather is unique;  
8 consequently, test year usage, hourly loads, revenue, and fuel and purchased power expense need  
9 to be adjusted to "normal" weather patterns so that rates will be designed on the basis of normal  
10 weather rather than any anomalous weather in the test year.

11 **Source of Weather Data** – In the quantification of the relationship between test year  
12 weather and energy sales, Staff used weather observations of the Springfield Regional Airport  
13 ("SGF") in Springfield, Missouri, for the update period, October 1, 2014, through September 30,  
14 2015.

15 As a measure of "normal" weather, Staff used a 30-year period of "climate normals"  
16 ("normals") by the National Climatic Data Center ("NCDC") of the U.S. National Oceanic and  
17 Atmospheric Administration ("NOAA"). According to NOAA, a climate normal is defined as  
18 the arithmetic mean of a climatological element computed over three consecutive decades.<sup>63</sup>  
19 To conform to the NOAA's three consecutive decades for determining normal temperatures,  
20 Staff used observed maximum and minimum daily temperatures for the 30-year period of  
21 January 1, 1981, through December 31, 2010. Therefore, Staff bases its calculations on the time  
22 period of the most recent climate normals produced by NCDC.<sup>64</sup>

23 Although the definition of normal weather is relatively simple, the actual calculations  
24 may be more complicated. Inconsistencies and biases in the 30-year time series of daily  
25 temperature observations occur if weather instruments are relocated, replaced, or recalibrated.  
26 Changes in observation procedures or in an instrument's environment may also occur during the  
27 30-year period. NOAA accounted for these anomalies in calculating the normal temperatures it  
28 published in July 2011.

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<sup>63</sup> Retrieved on January 27, 2016, <http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals>.

<sup>64</sup> Retrieved on January 27, 2016, <http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data>.

1 Staff verified the adjustments for anomalies in the SGF time series by direct  
2 communication with NCDC, and through Staff's own review of the daily observations.  
3 According to NCDC, the serially-complete monthly minimum and maximum temperature data  
4 sets have been adjusted to remove all inconsistencies and biases due to changes in the associated  
5 historical database. In addition, NCDC confirmed that the observed temperature data needs no  
6 adjustment in the period after 2001. Furthermore, Staff's review of NCDC's peer-reviewed,  
7 published paper<sup>65</sup> that explains the accuracy of the NCDC's monthly temperature series  
8 homogenization procedure for removing documented and undocumented anomalies, and found it  
9 to be meteorologically and statistically sound.

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

16 **Definition of Weather Variables** - Because weather fluctuates greatly from day-to-day,  
17 the SGF temperature variables required to weather-normalize sales are two-day weighted daily  
18 mean temperatures of the update period actual and the 30-year normal. The day's daily mean  
19 temperature is generally defined as the simple average of the day's maximum daily temperature  
20 and minimum daily temperature. The daily two-day weighted mean temperature is calculated  
21 using the previous day's mean daily temperature with a one-third weight and the current day's  
22 mean daily temperature with a two-thirds weight.<sup>66</sup>

23 This was done because yesterday's weather effects how electricity is used today in the  
24 Empire service area. This is likely due to heat retention by the structures in the service area. For  
25 example, if today's temperature is mild, but yesterday's temperature was hot and the air  
26 conditioner was on, it is likely that the air conditioner will also be used today. Similarly, if  
27 yesterday's temperature was mild and air conditioning was not used, then if today's temperature

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<sup>65</sup> Menne, M.J., and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, **22**, 1700-1717.

<sup>66</sup> 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:  $TWMT_D = (2/3) DMT_D + (1/3) DMT_{D-1}$

1 is slightly warmer, air conditioning may not be used until later in the day. Staff used the SGF  
2 daily two-day weighted mean temperature data series to normalize both class usages and hourly  
3 net system loads.

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

10 This results in the normal extreme being the average of the most extreme temperatures in  
11 each year of the 30-year normals period. The second most extreme temperature is based on the  
12 average of the second most extreme day of each year, and so forth. Staff’s calculation of daily  
13 normal temperatures is not the same as NOAA’s calculation of smoothed daily normal  
14 temperatures. Because the test year temperatures do not follow smooth patterns from day to day,  
15 Staff calculated normal daily temperatures based on the rankings of the actual temperatures of  
16 the update period.

17  
18 *Staff Expert/Witness: Seoung Joun Won Ph.D.*

### 19 **c. Weather Normalization**

20 In many of the classes of service, electricity consumption is highly responsive to the  
21 weather, specifically temperature. As the temperature increases, the demand for cooling, air  
22 conditioning and fans increases the customers’ consumption of electricity. As the weather  
23 becomes cold and temperature falls, the demand for additional heating, for example electric  
24 space heating, also forces an increase in electricity consumption. Because electric air  
25 conditioning and space heating is prevalent in Empire’s service territory, Empire’s electric load  
26 is linked and responsive to daily changes in temperature.

27 Staff used the most recent temperature and load data available for the updated period of  
28 October 1, 2014, through September 30, 2015, to capture a more likely, forward-looking  
29 indicator of non-weather electricity usage per customer. February 2015 experienced  
30 temperatures colder than normal, and June 2015 through July 2015 experienced temperatures  
31 hotter than normal, resulting in electric energy usage above that which would have been

1 expected under normal weather conditions. January 2015 and August 2015 experienced  
2 temperatures more mild than normal resulting in usage below that which would have been  
3 anticipated under normal conditions. The temperatures used by Staff in the update period  
4 deviated from normal, thus Staff performed a weather impact analysis.

5 Staff's model and methodology contained elements important in the class level weather  
6 normalization process; in particular, use of daily load research data to determine non-linear, class  
7 specific responses to changes in temperature with the incorporation of different base usage  
8 parameters to account for different days of the week, months of the year, and holidays. The  
9 results of Staff's analysis were provided to Staff witness Robin Kliethermes to be used in the  
10 normalization of revenues for the weather sensitive classes: Residential ("RG"), Commercial  
11 ("CB"), Small Heating ("SH"), Total Electric Building ("TEB") and General Power ("GP")  
12 classes.

13 Staff did not weather normalize the Large Power Service ("LP") class. The members of  
14 this class are not homogeneous and, consequently, a weather response function created for one  
15 member should not be applied to any other member. In addition, individual LP customer hourly  
16 usage data is not available. Staff concludes it is both appropriate and necessary to annualize  
17 rather than normalize LP for changes in customer usage and count. See Section X. A. 4. f.  
18 regarding Large Power Annualization by Staff witness Robin Kliethermes for a more detailed  
19 explanation of the annualization adjustments for the LP class.

20  
21 *Staff Expert/Witness: Seoung Joun Won, Ph.D.*

#### 22 **d. 365-Days Adjustment**

23 Calendar months and revenue months differ from one another because the periods they  
24 cover begin and end at different times. Calendar months coincide with the calendar, beginning  
25 on the first day of the month and ending on the last day of the month.

26 For weather sensitive classes, revenue months are an aggregation of bill cycles and begin  
27 on the first day of the first billing cycle and end on the last day of the last billing cycle. This  
28 aggregation of bill cycles may or may not coincide with a 365-day calendar year. In order to  
29 account for this difference, a "365-days adjustment" was calculated to convert the annual  
30 weather normalized revenue month usage to associate with the annual weather normalized  
31 calendar month usage. The adjustment was made to the update period months in proportion to



1 the actual usage occurring in each month and then appropriate rates were applied to determine  
2 the revenue adjustment.

3 For the Missouri Large Power class, rate revenue and usage is measured by revenue  
4 month (the period of time over which the staggered bill cycles result in each customer being  
5 billed precisely once) rather than by calendar month. The difference between total usage during  
6 the update period and 365 days gives us the 365-days adjustment.

7  
8 *Staff Expert/Witnesses: Robin Kliethermes and Seoung Joun Won, Ph.D.*

9 **e. Normalization and Annualization of Billing Determinants**

10 Staff normalized and annualized billing determinants for the RG, CB, SH, TEB, and  
11 GP rate classes, based on the normalized and annualized kWh factor.<sup>67</sup> For example, if the  
12 normalized and annualized kWh factor is 0.97 for the month of September in the RG rate class,  
13 then the total actual usage for that month and that rate class is decreased by 3%.

14 Staff adjusted actual billing determinants to equal the normalized and annualized monthly  
15 kWh using the relationship between actual average usage per customer and normalized and  
16 annualized average usage per customer. Staff also used the relationship between percentage of  
17 usage priced in the first rate block and the second rate block to distribute normalized and  
18 annualized monthly kWh to the rate blocks for rate classes RG, CB and SH. This calculation  
19 resulted in normalized usage by rate block, which was then converted to total normalized and  
20 annualized revenues by multiplying rate block usage by the appropriate rates.

21 The GP and TEB class billing units were similarly adjusted; however, the rate classes  
22 were subdivided by voltage with separate normalization and annualization adjustments being  
23 applied to each voltage level.

24 The overall difference between Empire's actual billing determinants and rate revenue and  
25 Staff's normalized and annualized billing determinants and rate revenue results in Staff's  
26 normalized and annualized kWh and revenue adjustments.

27  
28 *Staff Expert/Witness: Robin Kliethermes*

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<sup>67</sup> The normalized and annualized factors represent the impact of the weather normalization adjustment and the 365 day adjustment on actual usage calculated by Staff witness Seoung Joun Won.

1 **f. Missouri and Non-Missouri Large Power (“LP”) and Feed Mill &**  
2 **Grain Elevator Service (“PFM”) Annualizations**

3 Staff determined annualized, normalized update period usage and revenues for the rate  
4 classes LP and PFM on an individual customer basis.

5 The adjustments are for the update period of October 1, 2014, through September 30,  
6 2015. There were 38 customers in the Missouri LP rate class at the beginning of the update  
7 period: 3 customers switched to the GP class during the update period leaving 35 customers in  
8 the LP class at the end of September 2015.

9 Because each LP customer uses significant amounts of electricity, and the class is  
10 heterogeneous in electric use and load factor, class sales and revenues were annualized on an  
11 individual customer (account) basis. Each Missouri LP customer’s individual monthly demand  
12 and energy use, measured over multiple years prior to the update period in addition to the  
13 12 months of the update period, was examined graphically to determine whether an adjustment  
14 was needed.

15 Out of the 38 Missouri LP customers, no customer’s loads were adjusted. Since three LP  
16 customers switched during the update period, Staff removed those customer’s loads and revenues  
17 from the LP class and added those customers to the GP class. Staff also annualized the thirteen  
18 non-Missouri LP customers on an individual customer (account) basis.

19 Out of the 10 PFM customers, no PFM customer’s load was adjusted. One customer  
20 entered the PFM rate class; therefore that customer was annualized to reflect the gain.

21  
22 *Staff Expert/Witnesses: Robin Kliethermes, Kim Cox, Michelle A. Bocklage*

23 **g. Adjustments for Non-Missouri classes**

24 Staff adjusted the RG, CB, SH, TEB, and GP classes’ usage for non-Missouri customers  
25 for weather both to provide normalized kWh and for the days adjustment. These adjusted usages  
26 were provided to the Staff auditors for growth. Once Staff applied the growth adjustment, the  
27 final normalized and annualized usage was provided to Staff witness Shawn E. Lange for  
28 inclusion in Net System Input (“NSI”), and to Staff witness Alan J. Bax for inclusion in  
29 jurisdictional allocations.

30  
31 *Staff Expert/Witness: Robin Kliethermes*

1 **h. Rate Switching**

2 During the update period, excluding residential customers, approximately 37 customers  
3 switched rate classes. Table 1, below, shows a summary of the number of customers that  
4 switched between classes.  
5

**Table 1: Update Period Rate Switchers**

Rate	2014			2015								
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Commercial	-34	-31	-30	-30	-31	-30	-27	-24	-24	-5	-2	0
Small Heating	19	17	17	17	17	17	18	18	18	0	-1	0
General Power	11	10	9	10	10	9	6	2	2	2	2	0
Tot.Elec. Bldg	7	7	7	6	6	6	5	4	4	3	1	0
Large Power	-3	-3	-3	-3	-2	-2	-2	0	0	0	0	0
Total Retail	0	0	0	0	0	0	0	0	0	0	0	0

6  
7 Billing data indicated that customers represented in Table 1 switched rate classes for  
8 economic reasons rather than for changes in load. Customers who switched between classes due  
9 to changes in load were annualized through the customer growth adjustment. The overall effect  
10 of rate switching on usage nets to zero (one class' increase exactly equals the other class'  
11 decrease), however the overall effect of rate switching is a slight decrease to revenue.

12 Those customers who switched into and out of each of these classes were handled  
13 separately. The billing units and revenues of these customers were removed from their original  
14 rate code and their usage was added to their final rate code where it was re-priced to match rates  
15 in the final rate code.

16  
17 *Staff Expert/Witness: Robin Kliethermes*

18 **i. Customer Growth (Annualization)**

19 Staff made customer growth adjustments to test year kWh sales and rate revenue to  
20 reflect the additional kWh sales and rate revenue that would have occurred if the number of  
21 customers taking service at the end of the update period (September 30, 2015) had existed  
22 throughout the entire test year. Staff calculated customer growth for the RG, CB, SH, TEB, and  
23 GP customer classes.

1 The only retail customer rate classes for which this approach is not taken is the  
2 Large Power (“LP”) group and the Feed Mill and Grain Elevator Service (“PFM”) group. The  
3 process used for the LP and PFM rate classes is described in the above subsection f. of the  
4 Report. Staff’s customer growth adjustment to test year usage and resulting revenues for all  
5 retail customer groups combines the results of the analysis described above for RG, CB, SH,  
6 TEB, and GP in order to provide the annualized level of sales and revenues through the end of  
7 September 2015.

8  
9 *Staff Expert/Witnesses: Ashley R. Sarver and Robin Kliethermes*

10 **j. Annualization of Excess Facility Charge Revenues**

11 These revenues result from charges to customers for additional distribution facilities  
12 provided in excess of the distribution facilities normally made available to similarly sized  
13 customers. Staff annualizes these revenues for changes in the distribution facilities provided  
14 during the update period to determine the revenue that the Company would have earned had  
15 these additional facilities been in use the entire update period.

16  
17 *Staff Expert/Witness: Robin Kliethermes*

18 **k. Praxair and Special Contract Revenue Imputation**

19 Staff reviewed Praxair on an individual customer basis. After reviewing the update period  
20 data for Praxair, Staff determined that no annualization adjustment was required for that  
21 customer. The special treatment of the interruptible credits associated with Special Transmission  
22 Service Contract: Praxair, Schedule SC-P, continues effective through the update period;  
23 however, revenues were imputed as if the contract did not exist to prevent harm to other  
24 ratepayers.

25  
26 *Staff Expert/Witness: Sarah L. Kliethermes*

1                                   **5. Other Revenues**

2                                   **a. FAC Revenues**

3                   Staff removed from the Fuel Adjustment Clause (“FAC”) revenues from the Company’s  
4 starting point. This adjustment is made because this revenue will now be collected in base rates  
5 rather than through the FAC.

6  
7 *Staff Expert/Witness: Ashley R. Sarver*

8                                   **b. Unbilled Revenues**

9                   Staff has eliminated unbilled revenue from its determination of revenue requirement to  
10 ensure only 365 days of revenue are included and to reflect revenues on an “as billed” basis.  
11 The recording of unbilled revenue on the books of the Company recognizes sales of electricity  
12 that have occurred, but have not yet been billed to the customer. Therefore, it is necessary for  
13 Staff to remove unbilled revenue in order to reach an accurate revenue requirement based upon  
14 electricity sales billed to and revenues collected from Missouri customers.

15  
16 *Staff Expert/Witness: Ashley R. Sarver*

17                                   **c. Gross Receipts Revenues**

18                   For this item, Empire acts merely as a collecting agent and remits the taxes collected  
19 from customers to the appropriate taxing entities. The Gross Revenue Taxes (“GRT”), also  
20 known as city franchise taxes, included on a customer’s bill are collected by the Company and  
21 remitted to the appropriate taxing authority. The GRT included on a customers’ bill is recorded  
22 as revenue on the books of the Company, with a corresponding charge booked to GRT expense.  
23 Theoretically, the revenue and expense offset one another and, therefore, have no effect on net  
24 income. GRT are reported as both a revenue and expense item on Empire’s books. Staff has  
25 made adjustments to eliminate both the revenue and expense associated with GRT.

26  
27 *Staff Expert/Witness: Ashley R. Sarver*

28                                   **d. SO2 Allowances**

29                   On January 18, 2005, the Commission approved the *Unanimous Stipulation*  
30 *and Agreement* relating to Empire’s “SO2 Allowance Management Policy (“SAMP”)” in Case

1 No. EO-2005-0020 (“2005 Agreement”). In this document, the parties agreed that Empire  
2 should be allowed to manage its sulfur dioxide (“SO2”) emissions allowance inventory  
3 according to the SAMP as detailed in the 2005 Agreement. In this case, Case No. ER-2016-0023,  
4 Staff is not proposing an adjustment to SO2 Allowances.

5 SO2 Allowances are currently reflected in Empire’s FAC calculations and Staff  
6 recommends that this treatment continue.

7  
8 *Staff Expert/Witness: Ashley R. Sarver*

9 **e. Renewable Energy Credits (“REC”)**

10 In 2005, Empire began receiving wind energy from Elk River Wind farm pursuant to a  
11 contract. In addition, Empire began receiving wind energy from Cloud County Wind Farm in  
12 2008, also pursuant to contract. Empire is currently receiving wind energy from both of these  
13 entities to meet its customers’ energy demand. As a result of these contracts, Empire receives  
14 Renewable Energy Credits or Certificates (“RECs”), which are credits issued under the  
15 Center for Resource Solutions’ “green-e” program to certify that one megawatt-hour of  
16 electricity has been generated by a facility engaged in the production of renewable energy, such  
17 as wind, solar or biomass. RECs are tradable and can be bought and sold. Staff made an  
18 adjustment to remove non-Missouri jurisdictional accounts and to decrease REC revenues to the  
19 level realized during the twelve months ending September 30, 2015, the end of Staff’s updated  
20 period.

21  
22 *Staff Expert/Witness: Ashley R. Sarver*

23 **f. Water Revenues**

24 Empire recorded electric revenue amounts that relate to reconnect charges, trip charges,  
25 late fees, and return check fees associated with Empire’s water business. Staff has also  
26 eliminated these water revenue amounts related to the update period (12 months ending  
27 September 30, 2015) from the revenue requirement in this case.

28  
29 *Staff Expert/Witness: Ashley R. Sarver*

1 **g. Coal Fly Ash Revenues**

2 “Coal fly ash” is a byproduct created as a result of the burning of coal in generating  
3 stations to produce electricity. Fly ash has a number of possible industrial uses, primarily as an  
4 ingredient in concrete products. Over the past several years, Empire has been selling its fly ash  
5 to several different industrial companies to be used in concrete. By recycling fly ash, Empire not  
6 only receives a profit, but also provides positive environmental benefits. During the test year  
7 (EMS ER-2014-0351), Empire collected \$64,826 of revenue for the sale of this product. Staff  
8 analyzed a five-year average based on the updated test year period 12-months ending September  
9 30, 2015. There were no material differences since the last case so no adjustments to test year fly  
10 ash revenue amounts were made.

11 *Staff Expert/Witness: Ashley R. Sarver*

13 **h. Miscellaneous Revenues**

14 Empire’s miscellaneous other revenues consist of provisions for rate refunds, forfeited  
15 discounts, rents from property, reconnect, and surge arrester fees.

16 Staff’s analysis reflected a review of these revenue levels over a five-year period ending  
17 September 30, 2015. Based upon Staff’s review, the miscellaneous revenue levels at a twelve-  
18 month period ending September 30, 2015, appear reasonable for inclusion in customer cost of  
19 service, except for the provision of rate refunds. Staff made an adjustment to remove the  
20 provision for rate refunds recorded by Empire from the starting point in this case, because the  
21 refund amount does not pertain to the Missouri jurisdiction.

22 *Staff Expert/Witness: Ashley R. Sarver*

24 **B. Southwest Power Pool (“SPP”) Revenues and Expenses**

25 **1. SPP Transmission Revenues**

26 Empire receives revenues from the Southwest Power Pool (“SPP”) to reimburse it for  
27 costs associated with transmission of electricity to other SPP members. Staff reviewed the  
28 monthly amount of revenues received from SPP since November 2010 for any trends in the data  
29 which would indicate that a revenue amount other than the test year revenue would be  
30 appropriate to include in the cost of service. Staff’s review indicates that the total amount of SPP

1 revenues received in the period of October 2014 through September 2015, which is the end of  
2 the update period in the case, is the most appropriate amount to use to normalize the SPP  
3 transmission revenues.

4  
5 *Staff Expert/Witness: Amanda C. McMellen*

## 6 **2. SPP Transmission Expenses**

7 The SPP is a not-for-profit, regional transmission organization (“RTO”) which maintains  
8 functional control over the transmission assets of its members and provides transmission service  
9 through its Federal Energy Regulatory Commission (“FERC”) approved open access  
10 transmission tariff (“OATT”). SPP’s costs of providing transmission service must be recovered  
11 from its member companies, including Empire. Staff recommends that the most current data for  
12 the twelve months ending September 2015 be used in determining the SPP annualized  
13 transmission expense amount to reflect in Empire’s cost of service.

14  
15 *Staff Expert/Witness: Amanda C. McMellen*

## 16 **3. Ancillary Services Market Revenue and Expense**

17 Empire began participating in SPP’s Ancillary Services Market (“ASM”) in March 2014.  
18 Empire entered the ASM to acquire ancillary services for its retail load and also to be able to  
19 provide these services to other SPP members from its own generation when available. Ancillary  
20 services generally refers to the services necessary to support the transmission of capacity and  
21 energy from resources to loads while maintaining reliable operation of the transmission system.<sup>68</sup>  
22 Staff has annualized test year ASM revenue and expense levels by using data for the 12 months  
23 beginning October 2014 through September 2015, which is the end of the update period in this  
24 case. Staff will continue to review Empire’s ASM transactions as additional information  
25 becomes available throughout the true-up period.

26  
27 *Staff Expert/Witness: Amanda C. McMellen*

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<sup>68</sup> As defined, per the glossary on the SPP website.



1                                   **4. Miscellaneous SPP Related Revenues and Expenses**

2            Empire also received certain miscellaneous revenues and incurred expenses as a result of  
3 participating in SPP’s Integrated Market (“IM”) beginning in March 2014. Staff has annualized  
4 these revenues and expenses by using data for the 12 months beginning October 2014 through  
5 September 30, 2015, which is the end of the update period in this case. Staff will continue to  
6 review these miscellaneous revenues and expenses as additional information becomes available  
7 through the true-up period.

8  
9 *Staff Expert/Witness: Amanda C. McMellen*

10                                   **5. Off-system sales revenue and expense**

11            Off-system sales (“OSS”) is the difference in value between the energy Empire sells  
12 through the SPP IM and the energy Empire purchases through the SPP IM to serve its  
13 native load. In Staff’s fuel model run, Empire generated \$17.8 million in sales and purchased  
14 \$41.6 million of energy through the IM, resulting in net purchased power expense of  
15 \$23.8 million.

16  
17 *Staff Expert/Witness: Amanda C. McMellen*

18                                   **C. Fuel and Purchased Power**

19                                   **1. Fixed Costs**

20            Staff does not calculate within its fuel model those fuel and purchased power costs that  
21 do not vary directly with the amount of fuel burned. These costs are determined separately. The  
22 non-variable fuel costs included in fuel expense are typically referred to as fuel adders, described  
23 in the section below. The non-variable purchased power costs are referred to as capacity charges  
24 and these costs are annualized separately from purchased power energy costs.

25  
26 *Staff Expert/Witness: Keith D. Foster*

27                                   **a. Fuel Adders**

28            The costs of fuel adders are determined separately from fuel model costs and are added to  
29 the level of fuel expense calculated by the model to determine overall fuel expense. The fuel

1 adders in this case are natural gas transportation costs and freeze treatment costs for coal  
2 deliveries. Staff annualized the natural gas transportation expense based on Empire’s current  
3 contractual obligations with Southern Star which began on January 1, 2010. In regard to freeze  
4 treatment costs, all Powder River Basin (“PRB”) western coal delivered by rail to Asbury may be  
5 subject to being sprayed with a side release for freeze conditioning during the winter months.  
6 However, Staff could not confirm the treatment was being applied consistently in order to  
7 determine an annualized cost. Therefore, Staff used the actual costs for freeze treatment incurred  
8 for the twelve months ending September 30, 2015 (the update period), to add to the total  
9 fuel costs.

10  
11 *Staff Expert/Witness: Keith D. Foster*

#### 12 **b. Purchased Power – Capacity Charges**

13 In addition to its ownership interest in the Plum Point unit through Plum Point Energy  
14 Associates, LLC, Empire has contracted for a reservation of an additional 50 MW capacity from  
15 Plum Point through a purchased power contract. For this 50 MW of power, Empire pays a fixed  
16 component and an energy component. The fixed amounts Empire pays are referred to as  
17 capacity charges. Generally, there is an amount for Plum Point operation and maintenance costs  
18 included within the energy charge. The fixed component is paid as a “demand charge,”  
19 generally on a monthly basis, regardless of the level of power actually purchased. This amount  
20 is for the “right” to purchase the power in much the same way that natural gas utilities purchase  
21 reservation of capacity from pipelines through reservation payments. The demand charges are  
22 intended to cover part of the fixed expenses of operating a generating facility.

23 Staff’s adjustment to purchased power expense in this case annualizes demand charges  
24 for Empire’s Plum Point Purchase Power Agreement.

25  
26 *Staff Expert/Witness: Keith D. Foster*

#### 27 **c. Fuel Prices**

28 Generally, Staff computed its level of fuel expense using prices and quantities contracted  
29 by Empire for delivery in 2016, including prices and quantities agreed to in fuel contracts that  
30 will become effective as of January 1, 2016, (with one exception described in the “Coal Prices”

1 section below) and for current freight contracts. These fuel prices include prices for coal, natural  
2 gas, and oil, as well as associated transportation charges.

3  
4 *Staff Expert/Witness: Keith D. Foster*

5 **i. Coal Prices**

6 Staff determined its coal price by generation facility based on a review and analysis of  
7 Empire's current coal purchase and coal transportation contracts. Staff's recommended PRB  
8 coal prices reflect Empire's actual contracted coal purchase prices in effect at January 1, 2016,  
9 and a 12-month average of transportation costs incurred through the update period, September  
10 30, 2015. Staff's local bituminous coal price reflects Empire's actual contracted coal purchase  
11 price in effect at January 1, 2015. According to Empire, they are not purchasing this coal in  
12 2016, but are using what remains on the ground. For the Plum Point unit, Staff's recommended  
13 coal prices reflect the actual contracted coal purchase and transportation prices in effect for 2016.  
14 For the Iatan 1 and 2 units, Staff's recommended coal prices reflect KCPL's projected weighted  
15 average contracted coal purchase and transportation prices for 2016.

16  
17 *Staff Expert/Witness: Keith D. Foster*

18 **ii. Natural Gas Prices**

19 The natural gas price recommended in this case by Staff of \$3.25 per MMBtu  
20 is composed of two components: hedged and non-hedged ("spot") prices. Staff calculated the  
21 non-hedged component of natural gas prices using a twelve-month weighted average of Empire's  
22 actual commodity cost of natural gas purchased on the spot market during the twelve months  
23 ending September 30, 2015. The weighted average price for the non-hedged component is  
24 \$2.875 per MMBtu. Staff calculated the hedged component of natural gas costs by applying a  
25 weighted average for the actual hedged purchases contracted for at September 30, 2016, that is  
26 applicable to Empire's forecasted gas needs for the twelve months ending September 30, 2016.  
27 The weighted average price for the hedged component is \$3.495 per MMBtu. Staff weighted the  
28 hedged gas price at 60% of its overall gas price recommendation, as Empire has contracted to  
29 meet approximately 60% of its projected natural gas usage from October 1, 2015, through  
30 September 30, 2016, with hedged gas supplies. Empire's natural gas transportation costs are  
31 annualized and normalized separately as a part of fuel adders.

32  
33 *Staff Expert/Witness: Keith D. Foster*

1 **iii. Fuel Oil Prices**

2 Staff used a weighted average price of 1,831.04 cents per MMBtu to determine the  
3 fuel oil cost input in the fuel model in this case. Staff calculated this weighted average price by:  
4 (1) converting each month's number of barrels purchased over a 13-month period into gallons;  
5 (2) dividing a total month's purchase in gallons by that month's total purchase costs to derive an  
6 average monthly price per gallon; (3) summing the totals for the 13-month period to calculate a  
7 weighted 13-month average cost per gallon which, in this case, is \$2.552471; and (4) converting  
8 this per gallon price into the cents per MMBtu, 1,831.04. Empire burns fuel oil mainly as a  
9 secondary fuel or, in some instances, for flame stabilization. Empire does maintain onsite  
10 storage at its various facilities in sufficient capacity that only occasional purchases are necessary.  
11 As a result, Empire does not contract for or hedge oil costs.

12  
13 *Staff Expert/Witness: Keith D. Foster*

14 **2. Losses**

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

20 The basis for calculating system energy losses is that Net System Input ("NSI") equals  
21 the sum of "Retail Sales," "Wholesale Sales," "Company Use" and "System Energy Losses."  
22 This can be expressed mathematically as:

23 
$$\text{NSI} = \text{Retail Sales} + \text{Wholesale Sales} + \text{Company Use} + \text{System Energy Losses}$$

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

26 
$$\text{System Energy Losses} = \text{NSI} - (\text{Retail Sales} + \text{Wholesale Sales} + \text{Company Use})$$

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

28 
$$\text{System Energy Loss Percentage} = (\text{System Energy Losses} \div \text{NSI}) \times 100$$

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

7 Staff calculated the loss percentage of Empire's system, for the twelve months ending  
8 September 2015, as 6.24% of NSI. Staff witness Seoung Joun Won used this loss percentage in  
9 the development of hourly loads used in Staff's fuel model.

10  
11 *Staff Expert/Witness: Alan J. Bax*

### 12 **3. Variable Costs**

13 Staff estimates Empire's variable fuel and purchased power expense to be \$113,411,072  
14 for the twelve months ending September 31, 2015.

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

21 Staff used market prices in its fuel model dispatch to simulate Empire's operations in the  
22 SPP's IM. The price for energy in the IM dictates the amount of energy Empire sells in the IM.  
23 Consequently, Staff's fuel run dispatches Empire's generation to match Empire's load, thus  
24 simulating how the SPP would dispatch generation if it were being dispatched into the SPP IM  
25 based on prices set by the SPP's regional load requirements.

26 The model operates in a chronological fashion, meeting each hour's energy demand  
27 before moving to the next hour. It will schedule generating units to dispatch in a least cost  
28 manner based upon fuel cost and purchased power cost while taking into account generation unit  
29 operation constraints and firm purchased power contract requirements. This model closely

1 simulates the way a utility should dispatch its generating units and purchase power to meet the  
2 net system load in a least cost manner.

3 Staff calculated the following inputs for use in the model: fuel prices, firm purchased  
4 power contract specifications, spot market purchased power prices and availability, hourly NSI,  
5 and unit planned and forced outages. Staff relied on Empire's responses to data requests, and  
6 data Empire supplied to comply with 4 CSR 240-3.190, for the characteristics of each generating  
7 unit; for example: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up  
8 rate, startup costs, and fixed operating and maintenance expense. Information from Empire's  
9 firm wholesale loads and firm purchased power contracts such as hourly energy available and  
10 prices are also inputs to the model.

11  
12 *Staff Expert/Witness: Shawn E. Lange*

#### 13 **4. Planned and Forced Outages**

14 Planned and forced outages are infrequent in occurrence, and variable in duration. In  
15 particular, forced outages are unplanned and can happen at any time. In order to capture this  
16 variability, Empire generating unit outages were normalized by averaging the eleven years  
17 ending October 2015 of actual values taken from responses to data requests, and data Empire  
18 supplied to comply with 4 CSR 240-3.190.

19  
20 *Staff Expert/Witness: Shawn E. Lange*

#### 21 **5. Energy Sales and Purchases**

22 Staff used market prices in its fuel model dispatch to simulate Empire's operations in the  
23 SPP's IM. The price for energy in the IM dictates the amount of energy Empire sells in the IM.  
24 Consequently, Staff's fuel run dispatches Empire's generation to match Empire's load, thus  
25 simulating how the SPP would dispatch generation if it were being dispatched into the SPP IM  
26 based on prices set by the SPP's regional load requirements.

27  
28 *Staff Expert/Witness: Shawn E. Lange*

1                                   **6. Capacity Contract Prices and Energy**

2           Capacity contracts are contracts entered into between electric providers for a specific  
3 amount of capacity (megawatts) and/or a maximum amount of hourly energy (megawatthours).  
4 Prices for the energy from these capacity contracts are based on either a fixed contract price or  
5 the generating costs of providing the energy. Empire’s capacity contracts include the Elk River  
6 and Meridian Way Wind contracts, and the Plum Point contract.

7           Empire’s actual hourly contract transaction prices were obtained from the data Empire  
8 supplied to comply with 4 CSR 240-3.190 and were used by Staff to calculate each contract’s  
9 average monthly prices.

10  
11 *Staff Expert/Witness: Shawn E. Lange*

12                                   **7. Normalized Net System Input (“NSI”)**

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

16           Due to the presence of significant air conditioning and electric space heating in Empire’s  
17 service territory, the magnitude and shape of Empire’s NSI is directly related to daily  
18 temperatures. To normalize NSI, Staff used actual and normal daily temperatures provided by  
19 Staff witness Seoung Joun Won in its analysis. The actual daily temperatures for the update  
20 period, twelve months ending September 30, 2015, differed from normal daily temperatures.  
21 Therefore, to reflect normal weather, daily peak and average net system loads are each adjusted  
22 independently, but using the same methodology.

23           Daily average load is the summation of the hourly load for the day divided by  
24 twenty-four hours. Daily peak is the maximum hourly load for the day. Staff uses separate  
25 regression models to estimate both (1) a base component, which is allowed to fluctuate across  
26 time as non-weather factors, and (2) a weather sensitive component, which measures the  
27 response to daily fluctuations in weather for daily average loads and peak loads. Independent  
28 regression models are necessary because daily average loads respond differently to weather than  
29 peak loads. The models’ regression parameters, along with the difference between normal and  
30 actual cooling and heating measures, are used to calculate weather adjustments to both the

1 average and peak loads for each day. The adjustments for each day are added respectively to the  
2 actual average and to the peak loads of each day. The starting point for allocating the weather-  
3 normalized daily peak and average loads to the hours is the actual hourly loads for the year being  
4 normalized. A unitized load curve<sup>69</sup> is calculated for each day as a function of the actual peak  
5 and average loads for that day. Staff uses the corresponding weather normalized daily peak and  
6 average loads, along with the unitized load curves, to calculate weather normalized hourly loads  
7 for each hour of the year.

8 This process includes many checks and balances, which are included in the spreadsheets  
9 that are used by Staff. In addition, the analyst is required to examine the data at several points in  
10 the process. For more information, the process is described in greater detail in the document  
11 *Weather Normalization of Electric Loads, Part A: Hourly Net System Loads*.<sup>70</sup>

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

17 Staff applies a factor to each hour of the weather-normalized loads to produce an annual  
18 sum of the hourly net-system loads that equals the usage, plus losses, consistent with normalized  
19 revenues. Once completed, the hourly normalized system loads were used in developing fuel and  
20 purchased power expense. Staff witness Alan J. Bax also used the annual requirement of the net  
21 system load in developing Staff's jurisdictional energy allocator.

22  
23 *Staff Expert/Witnesses: Shawn E. Lange and Seoung Joun Won, Ph.D.*

## 24 **8. Purchased Power Prices**

25 Staff's fuel model requires a set of spot market power prices for each hour in the model.  
26 Staff analyzed hourly day-ahead SPP IM locational marginal power prices from the onset of the

---

<sup>69</sup> A unitized load curve is a set of 24 hourly loads of a given day by subtracting the average daily load from each hourly load, then dividing by the difference between the peak and the average so that the average of the calculated hourly loads is 0 and the peak is 1.

<sup>70</sup> *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 IM on March 1, 2014, through September 30, 2015, to determine monthly average peak and  
2 off-peak pricing at the Empire generator nodes and the Empire load node.

3 Staff updated the set of purchased power prices used in the final Staff EMS run from the  
4 previous rate case based on the public data available on the SPP website through September 30,  
5 2015. Staff will update this set of purchased power prices using the SPP IM data through  
6 March 31, 2016.

7  
8 *Staff Expert/Witness: Erin L. Maloney*

## 9 **9. Entergy Transmission Contract**

10 Empire has a contract with Entergy Solutions, Inc., for Firm Point-to-Point Transmission  
11 Service to transmit power generated from the Plum Point Energy Station to Empire. Staff  
12 included an adjustment that annualizes the cost of this service at the current contract rate  
13 effective September 30, 2015.

14  
15 *Staff Expert/Witness: Jermaine Green*

## 16 **D. DEPRECIATION**

### 17 **1. Depreciation Rates**

18 In the recent KCP&L, KCP&L-GMO, and Ameren Missouri cases, Case Nos.  
19 ER-2010-0355, ER-2010-0356, and ER-2010-0036, respectively, the Commission accepted the  
20 use of the life span method and remaining life technique for developing depreciation rates. In the  
21 case at hand, Staff performed a depreciation study using these methods for Empire's production  
22 accounts, which resulted in the depreciation rates for production plant accounts set out in  
23 Schedule JAR(DEP) – d1. Staff performed this depreciation study using the same depreciation  
24 data set that Empire provided to its depreciation consultant.

25 Staff recommends for the Transmission, Distribution, and General Plant  
26 accounts the continued use of Whole Life Mass Asset depreciation rates as set out in  
27 Schedule JAR(DEP) - d1. Mass asset accounts differ from unit property accounts in that they  
28 represent many similar units rather than a distinct entity. When a unit under one of these  
29 accounts is retired, such as a meter, pole, or section of conductor, it is usually replaced with

1 another unit with similar life characteristics. Though individual units will retire at a particular  
2 time, collectively the service life is indefinite because the units are of different ages and they  
3 retire after different lifespans because of factors that are essentially random such as  
4 manufacturing variances, location, user characteristics, weather, or accidents. In such cases,  
5 actuarial methods are used to project future retirements based on the history of the account. This  
6 approach was used for these accounts in previous Empire cases as well as in the study submitted  
7 by Empire's depreciation consultant.

## 8 **2. Stopped Depreciation Accrual/Set Depreciation Rate to 0 Percent**

9 In Staff's review of Empire's depreciation study, Staff found depreciation rate  
10 recommendations of 0 percent for five accounts on a going-forward basis. These accounts are:  
11 State Line Combined Cycle plant account 342 Fuel Holders, State Line Combustion Turbine  
12 account 341 Structures and Improvements, Energy Center Units 1 and 2 accounts 342 Fuel  
13 Holders, account 344 Generators, and account 346 Miscellaneous Power Equipment. Staff  
14 submitted nine data requests related to the recommendation of 0 percent depreciation rates.  
15 Empire's responses indicate that it is setting depreciation rates to 0 percent for accounts where  
16 reserves are equal to or higher than original cost. This is not the first time Staff has found that  
17 Empire has prematurely stopped depreciation accrual on an account or specific asset.

18 In Case No. ER-2011-0004, Robinett Surrebuttal, Staff identified that the sale of one of  
19 Empire's unit trains had been improperly handled and needed additional investigation. In Case  
20 No. ER-2012-0345, Staff investigated that unit train and made the following statement in the  
21 Cost of Service Report for Case No. ER-2012-0345:

22 The second issue related to the steel unit train at the Asbury  
23 generating facility is that the Company stopped recording accrual  
24 of depreciation expense on the unit train from April 2007 through  
25 November 2007 when the unit train was sold. The Company  
26 continued to collect depreciation during the entire time of the lease  
27 when the Company was receiving income from a non-utility party.  
28 The Company fully collected the original cost of the unit train in  
29 March of 2007. In April of 2007 the Company stopped  
30 accumulating depreciation on the unit train, which would mean the  
31 Company was then collecting those dollars built into rates  
32 associated with the unit train depreciation expense as profit rather  
33 than booking an accrual to accumulated depreciation reserves, as  
34 the Commission previously ordered in Case No. ER-2005-0470.  
35 Staff recommends an adjustment to the depreciation reserves for

1 account 312 with a total Company addition of \$248,137 for  
2 stopped depreciation accrual related to the eight (8) months prior to  
3 the sale of the unit train.<sup>71</sup>

4 Empire, as part of a *Stipulation and Agreement* in Case No. ER-2012-0345, agreed to make the  
5 reserve adjustments to properly reflect the sale and stopped depreciation accrual of the unit train  
6 at the Asbury facility to Asbury account 312 Boiler Equipment.

7 In the case at hand, Case No. ER-2016-0023, Staff calculated and recommends  
8 \$3,082,367 of adjustments to depreciation reserves to reflect depreciation accruals that should  
9 have been booked during the period when depreciation rates were set to 0 percent. However,  
10 because of issues transitioning from paper to electronic records, Staff is uncertain of all of the  
11 accounts for which Empire has been using 0 percent depreciation rates and of the total shift that  
12 should occur. Staff is currently aware of 14 accounts or subaccounts that have stopped accruals  
13 for differing lengths of time since 2005. Only two accounts that Staff is currently investigating  
14 appear to have appropriate accruals; however, the investigation is ongoing and Staff may update  
15 its position regarding these accounts following its completion. The accounts that appear to have  
16 appropriately ceased to accrue depreciation are accounts 314 and 316 for Riverton Units 7 and 8.  
17 All of the plant has been retired so no accrual would be taking place. However, if the  
18 Company changed the depreciation rates for these accounts to zero then that treatment was  
19 incorrect. Here is the current list of accounts where depreciation accruals have stopped for a  
20 period of time since 2005:

21 Riverton Units 7 and 8 accounts 314 and 316;  
22 Energy Center Units 1 and 2 accounts 342, 344, and 346;  
23 State Line CT accounts 341 and 346;  
24 State Line CC account 342;  
25 Iatan 1 account 316I;  
26 Iatan Common accounts 314IC, 315IC, and 316IC;  
27 Transmission account 352I related to Iatan; and  
28 Transmission Account 354 Towers and Fixtures.

29 Staff calculated the adjustments for depreciation reserves for the affected accounts. Staff  
30 recommends adjustments that total \$3,082,367. The adjustments are all positive adjustments to  
31 reserves for the affected accounts and are as follows:

---

<sup>71</sup> Case No. ER-2012-0345, Staff Cost of Service Report, page 100, line 26 -page 101, line 5, EFIS Item 123 filed 11/30/2012.

**ESTIMATED ACCRUED DEPRECIATION ADJUSTMENTS**  
**EMPIRE DISTRICT ELECTRIC COMPANY**  
**ER-2016-0023**  
**2005-2015**

<b>Plant/ Facility</b>	<b>Depreciation Group</b>		<b>Adjustment</b>
Energy Center	342E	Fuel Holders, Producers & Access.	\$480,325
	344E	Generators	\$742,576
	345E	Accessory Electric Equipment	\$60,329
	346E	Miscellaneous Power Plant Equipment	\$537,488
	Plant Total		\$1,820,717
Energy Center FT8	342FT	Fuel Holders, Producers & Access.	\$3,354
Iatan	312IT	Boiler Plant Equipment	\$15,724
	316IT	Miscellaneous Power Plant Equipment	\$35,459
	Plant Total		\$51,183
Iatan 2	316I2	Miscellaneous Power Plant Equipment	\$526,273
Iatan Common	314IC	Turbogenerator Units	\$2
	315IC	Accessory Electric Equipment	\$25
	Plant Total		\$27
Iatan Transmission	352I	Structures & Improvements	\$25,213
	353I	Station Equipment	\$11,339
	Plant Total		\$36,552
Riverton	314R	Turbogenerator Units	\$166,558
	315R	Accessory Electric Equipment	\$94,621
	316R	Miscellaneous Power Plant Equipment	\$24
	Plant Total		\$261,203
Stateline	341S	Structures & Improvements	\$227,197
	346S	Miscellaneous Power Plant Equipment	\$85,345
	Plant Total		\$312,542
Stateline CC	342C	Fuel Holders, Producers & Access.	\$62,170
Transmission	354	Towers & Fixtures	\$8,345
GRAND TOTAL			\$3,082,367

**3. “Shortfall / Deficiency” for the Retirement of Riverton Units 7 and 8**

Staff has reviewed the unrecovered reserves associated with the retirement of Riverton Units 7 and 8. Staff estimates that accounts related to Riverton Units 7 and 8 are under-recovered by \$7.8 million. As the Company and Staff previously agreed in Case No. ER-2012-0345:

Should the retirement of Riverton 7 or 8 create a reserve deficiency under Generally Accepted Accounting Principles (GAAP), the signatories agree to support a reasonable request by Empire for accounting authority pursuant to Accounting Standard 980 (FAS 71) to reallocate the depreciation reserve to cover the cost of removal of such plant.

Depreciation Staff recommends the following transfers of reserves:

<b>DEPR GRP</b>	<b>FERC USOA DESCR</b>	<b>Adjustments</b>
<b>RIVERTON 7&amp;8</b>		
311R	Structures	\$ 3,442,188
312R	Boiler Plant	\$ 4,831,496
314R	Turbogenerators	\$ 1,390,628
315R	Access. Electric	\$ 410,252
316R	Misc. Equipment	-\$ 41,047
<b>IATAN 1</b>		
316I	Misc. Equipment	-\$ 436,275
<b>ENERGY CENTER</b>		
341E	Structures	-\$ 697,697
342E	Fuel Holders	-\$ 791,573
344E	Generators	-\$ 3,894,864
346E	Misc. Equipment	-\$ 2,046,394
<b>STATE LINE UNIT 1</b>		
341S	Structures	-\$ 528,654
346S	Misc. Equipment	-\$ 127,963
<b>STATE LINE CC</b>		
342C	Fuel Holders	-\$ 1,510,097

Depreciation Staff is not recommending an amortization of the unrecovered reserve as requested by Empire. Staff instead recommends transferring reserves to cover the under recovered portion of Riverton Units 7 and 8. In addition to the reserve adjustments for reserve deficiency, Staff is recommending a 10% depreciation rate on the remaining assets related to Riverton steam

1 production plant; this rate equates to approximately \$300,000 of annual depreciation expense.  
2 Empire's depreciation study estimated the cost of removal for Riverton Units 7, 8, and 9 to be  
3 approximately \$3 million. Staff's recommended transfer of reserves does not cover the full  
4 estimated cost of removal for Riverton Units 7, 8, and 9. Hopefully between the transfer of  
5 reserves and the continued depreciation or remaining steam assets, the reserve totals will contain  
6 close to the final costs to remove the retired plants.

#### 7 **4. Riverton 12 CC Estimated Depreciation Expense**

8 Staff has calculated an approximation of the depreciation expense related to the  
9 conversion of Riverton Unit 12 to a combined cycle unit. The estimated plant balances Staff used  
10 to calculate the estimated depreciation expense for the conversion of Riverton are from Data  
11 Request No. 0019 from File No. EO-2014-0069. This conversion is expected to be placed into  
12 service and included as part of the true-up. Staff's projected depreciation expense for plant  
13 investment related to the conversion is an increase of Missouri Jurisdictional depreciation  
14 expense of \$2,526,049. Staff's current depreciation rate recommendation for Riverton Unit 12 is  
15 based on Riverton Unit 12 as a combustion turbine unit, not as a combined cycle unit. Staff  
16 reserves the right to update depreciation rates related to Riverton Unit 12 conversion at the time  
17 of true-up in this case.

#### 18 **5. Recommendations**

19 Staff recommends the Commission order the following:

- 20 1. The Commission order the depreciation rates for the production accounts  
21 requested by Staff in recognition of the Commission's Orders accepting the  
22 methods and assumptions used in the recent KCP&L, KCP&L-GMO, and  
23 Ameren Missouri cases ER-2010-0355, ER-2010-00356, and ER-2010-0036,  
24 respectively as shown in Appendix 3, Schedule JAR(DEP) - d1.
- 25 2. The Commission order Empire to use the depreciation rates for the  
26 transmission, distribution, and general plant accounts as shown in  
27 Appendix 3, Schedule JAR(DEP) - d1.
- 28 3. The Commission order Empire to book the adjustments to depreciation  
29 reserves related to stopped depreciation; reserve adjustments found in table  
30 on page 94 of Staff Cost of Service Report.
- 31 4. The Commission order Empire to perform the reserve transfers proposed by  
32 Staff to cover the reserve short fall at Riverton Units 7 and 8; Staff

1 recommended transfers are found in table on page 95 of Staff Cost of Service  
2 Report.

- 3 5. The Commission not authorize the amortization recommended by Empire to  
4 recover the under recovery of reserves at Riverton Units 7 and 8.

5  
6 *Staff Expert/Witness: John A. Robinett*

7 **E. RIVERTON 12 O&M TRACKER**

8 On January 1, 2015, Empire entered a Long-term Maintenance Contract with Siemens for  
9 the maintenance of Unit 12 at the Riverton plant. This contract is similar to the agreement at  
10 Empire’s State Line Combined Cycle facility in which Siemens conducts maintenance service  
11 for the turbines, which are required to run for a specified number of hours. The cost breakdown  
12 of this agreement with Siemens includes an initial fee, an hourly rate based on the variable  
13 equivalent operating hours (“EOH”), and an annual fixed fee.

14 In Empire’s last rate case, No. ER-2014-0351, Staff recommended that a tracker be  
15 established with a base annual amount of \*\* \_\_\_\_\_ \*\* Missouri Jurisdictional, for  
16 Riverton 12 maintenance expenses. This tracker mechanism was agreed to in the  
17 *Non-Unanimous Stipulation and Agreement* in Case No. ER-2014-0351. The fluctuations of  
18 Riverton 12 O&M expenses above or below this annual base level of \*\* \_\_\_\_\_ \*\* have  
19 been recorded as a regulatory asset/liability. Staff’s methodology for determining the  
20 Riverton 12 tracker base was based on Empire’s projected equivalent operating hours at the  
21 contracted rate. Staff did not include 2,475 equivalent operating hours that the Company  
22 “anticipated” for the commissioning of the new Riverton 12 unit as a combined cycle generation  
23 unit in the tracker base, as it was Staff’s position that these hours represent a one-time cost and  
24 should not be included in ongoing expense levels or in a tracker mechanism. Instead, these costs  
25 should be treated as a capital item.

26 In this current case, Empire is proposing to rebase the Riverton 12 O&M tracker from  
27 \*\* \_\_\_\_\_ \*\* of annual expense based on a new estimated equivalent  
28 operating hours calculation. It is Staff position that the tracker base level should remain at  
29 \$2.7 million until there is a sufficient operational history to determine a true estimate. Staff will

1 perform a review of the actual O&M expenses incurred by Riverton 12 during the true-up phase  
2 of this case to determine if a rebase is reasonable at that time.

3  
4 *Staff Expert/Witness: Jermaine Green*

## 5 **F. Payroll and Benefits**

### 6 **1. Payroll, Payroll Taxes and 401(k)**

7 Staff adjusted Empire's test year payroll expense to reflect an annualized level of payroll,  
8 payroll taxes, and 401(k) benefit costs as of September 30, 2015. Base payroll was calculated by  
9 multiplying employee levels at September 30, 2015, by the then-current appropriate salary or  
10 wage rate to derive the annualized payroll cost. Overtime payroll for Empire was calculated for  
11 each full-time hourly employee based upon: (1) an overtime percentage computed for non-union  
12 five-year average of overtime hours actually incurred, (2) multiplying that by the current average  
13 rate paid for overtime as of September 30, 2015, and (3) dividing the product by Staff's  
14 *pro forma* base without inclusion of overtime hours for storms related to emergency events in  
15 which Empire assisted other utilities and the May 2011 Joplin tornado. In regards to the Joplin  
16 tornado, the Commission granted Empire an Accounting Authority Order ("AAO") to defer all  
17 incremental O&M costs associated with the tornado. Any overtime costs incurred as a result of  
18 this tornado needed to be removed in order to avoid a situation where Empire could potentially  
19 recover those costs twice in rates.

20 An allocation rate for distributing the payroll adjustment to Empire's electric operations  
21 was determined by using the percentage of Empire's electric operating payroll costs to its total  
22 payroll costs (including electric construction, water operations, etc.). After allocation between  
23 expense and construction, the adjustment for payroll was distributed by Federal Energy  
24 Regulatory Commission Uniform System of Accounts ("FERC USOA") based upon the actual  
25 distribution experienced by Empire for the twelve months ending April 30, 2014, which was  
26 established in the last rate case, No. ER-2014-0351. Staff's Accounting Schedule 10,  
27 Adjustments to the Income Statement, reflects all payroll adjustments, segregated by FERC  
28 USOA Accounts, to reflect Staff's total adjustment required to restate the test year payroll to an  
29 annualized level as of September 30, 2015.



1 Staff calculated payroll taxes based upon September 30, 2015, wage levels and current  
2 tax rates. This included Federal Unemployment Taxes (“FUTA”), State Unemployment Taxes  
3 (“SUTA”), and Federal Insurance Contributions Act (“FICA”) tax. In addition, FICA payroll  
4 taxes were computed for allowable non-earnings based incentive payments incurred in the test  
5 year. The Company’s 401(k) benefit costs were annualized by applying Empire’s actual 401(k)  
6 match rate for each employee to the annualized payroll as of September 30, 2015.

7  
8 *Staff Expert/Witness: Jermaine Green*

## 9 **2. Incentive Compensation**

10 Staff reviewed Empire’s portfolio of incentive compensation plans offered to  
11 its employees. Based upon this review, Staff is proposing adjustments to the Company’s  
12 incentive compensation expenses related to the Management Incentive Compensation Plan  
13 (“MIP”), lump-sum payments offered to certain employees called “Lightning Bolts,” and equity  
14 incentive compensation offered to the Company’s executives. These disallowances are not stated  
15 as separate income statement adjustments, but are embedded within Staff’s previously described  
16 total payroll adjustments.

### 17 **a. Management Incentive Compensation Plan (“MIP”)**

18 Empire’s MIP program offers awards to Empire senior officers for the achievement of  
19 certain pre-set goals. In 2014, each senior officer had a list of goals pertaining to areas such as  
20 expense control, capital markets, regulatory performance, customer service, project completion,  
21 operations, financial performance, corporate governance, and safety. Each of these goals was  
22 given a specific performance measure and weighting, thus assigning a target cash payout.  
23 The amount of the award determination would have been based upon attainment of a specific  
24 performance level by the senior officer:

25 Threshold (50% of target payout)

26 Target (100% target payout)

27 Maximum (200% of target payout)

28 If the results for a specific goal were below the threshold, the senior officer would not  
29 have received an MIP award related to that specific goal. If the results were at or above the level

1 set for the maximum goal, the senior officer would have received double the target MIP award  
2 for that specific goal.

3 In order to determine the appropriate amount to include for the MIP in this case, Staff  
4 performed a review of all the incentive metrics used to measure each individual goal and the  
5 actual award received. Staff then disallowed all the actual awards paid out to Empire's  
6 executives and department heads associated with the performance measure of meeting earnings  
7 per share targets. In Staff's review of the incentive metrics, it was determined that the earnings  
8 per share performance measure accounted for 20.72% of the total incentive award paid out. Any  
9 incentive goals associated with enhancing the value of a utility's stock price and the achievement  
10 of these goals benefits Empire's shareholders, not Empire's ratepayers; therefore, Staff removed  
11 this expense from inclusion in rates.

#### 12 **b. Lightning Bolts**

13 Empire's "Lightning Bolts" program offers one-time incentive payments in the nature of  
14 bonuses to certain employees. Staff has disallowed the cost of these discretionary bonuses paid  
15 in 2015. The Commission's *Report and Order* in Case No. ER-2006-0315 adopted Staff's  
16 recommended disallowance of short-term incentive compensation tied to discretionary bonuses  
17 that are unsupported by well-defined goals and for which the criteria for granting awards is not  
18 known to the employee in advance.

#### 19 **c. Equity Incentive Compensation**

20 In Empire's past rate cases, Staff also recommended a disallowance of long-term stock  
21 incentive compensation awarded to Empire's executive management, which results in the  
22 issuance of stock annually that is considered to be part of the senior officer's total compensation.  
23 The senior officers do not have any specific goals to meet in order to be granted these stock  
24 options. Awarding these stock options benefits Empire's shareholders, not Empire's ratepayers.  
25 Additionally, unlike other expense recognition in the income statement, expense recognition for  
26 equity-based incentive compensation does not result in a cash outlay by Empire. Staff has  
27 eliminated stock options recognized as an expense in this case consistent with the Commission's  
28 *Report and Order* in Case No. ER-2006-0315.

29  
30 *Staff Expert/Witness: Jermaine Green*

1                                   **3. Payroll Benefits**

2            Empire currently offers its employees Dental, Vision, Healthcare, and Life Insurance  
3 benefits. Staff performed an analysis of the employee benefit costs included in Account 926 from  
4 the general ledger. Staff annualized each expense by examining the individual costs over a  
5 three year period to determine the appropriate amount to include for each expense. Staff  
6 performed a three-year average through the update period to annualize these expenses ending  
7 September 30, 2015.

8  
9    *Staff Expert/Witness: Jermaine Green*

10                                   **4. FAS 87 and FAS 88 Pension Costs**

11            In Case No. ER-2004-0570, the Staff, Empire and other parties entered into a  
12 *Stipulation and Agreement as to Certain Issues*, addressing, among other items, the ratemaking  
13 treatment for annual pension cost under Financial Accounting Standard No. 87 (“FAS 87”). This  
14 agreement, and thus treatment of annual pension cost, was later modified by each of the later  
15 *Stipulation and Agreement as to Certain Issues* entered into in Case Nos. ER-2006-0315,  
16 ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2014-0351.  
17 (Collectively, Staff will refer to the *Stipulations and Agreements* regarding pension expense  
18 ratemaking from the 2004 rate case to current as the “Pension Agreements.”) These above-  
19 referenced Pension Agreements provide for Empire to generally have its pension rate allowance  
20 set equal to its most current annual level of pension expense as calculated under FAS 87.  
21 Furthermore, these agreements established a tracker mechanism for Empire’s pension expense,  
22 in which any excess or deficit in the Company’s pension rate allowance, as compared to its  
23 ongoing levels of FAS 87 expense, is to be treated as a regulatory asset or liability. The resulting  
24 pension tracker regulatory asset or pension tracker regulatory liability is then to be included in  
25 Empire’s rate base, and amortized as an addition or reduction to pension expense over a five-  
26 year period.

27            Pension cost under FAS 87 has been reflected in Staff’s income statement for this case in  
28 a manner consistent with the ratemaking treatment agreed upon by the signatories to all of the  
29 stipulation and agreements approved by the Commission in Empire’s last seven electric rate  
30 cases. Empire’s rate base, as determined by the Staff, includes the FAS 87 Regulatory Asset,

1 which represents the cumulative difference between FAS 87 pension costs recovered in rates and  
2 FAS 87 pension costs recognized in the financial statements between rate cases.

3 Additionally, Staff has included a prepaid pension asset (“PPA”) in rate base in the  
4 amount of \$22,169,990. The PPA represents the cumulative amount of contributions in excess of  
5 actual costs as of September 30, 2015. These contributions were made to prevent the pension  
6 plan from becoming “at-risk” as defined under the Pension Protection Act, and to meet the  
7 obligations of the Pension Benefit Guarantee Corporation. Staff’s cost of service does not  
8 include an amortization of this PPA. Future contributions to the pension plan will be reduced by  
9 this PPA amount.

10 Empire’s pension costs in this case were based upon the Company’s actuary report,  
11 Exhibit 1 of Empire’s 2015 Pension Expense and workpapers. Staff will update its current  
12 projection of pension costs, tracker balance and amortization in its True-Up testimony.  
13 The results of the Staff’s review to date of Empire’s pension costs are as follows:

- 14 1. The Company’s ongoing FAS 87 expense recognized in rates in  
15 this case is \$7,664,807.
- 16 2. Empire has under-recovered its FAS 87 expense in rates compared  
17 to its actual level of expense since the Company’s last rate case.  
18 The balance in the Regulatory Asset account at September 30,  
19 2015, was \$2,945,242, which is to be amortized over five years as  
20 an expense in the amount of \$589,048
- 21 3. The amount to be included in rate base for Empire’s ongoing  
22 pension expense tracker mechanism is \$2,945,242, as noted above.
- 23 4. An amount of \$22,169,990 is included in Empire’s rate base as a  
24 prepaid pension asset.

25 *Staff Expert/Witness: Paul R. Harrison*

## 26 **5. FAS 106 – Other Post-Employment Benefit Costs (“OPEBs”)**

27 In Case No. ER-2006-0315, the signatory parties entered into a *Non-Unanimous*  
28 *Stipulation and Agreement as to Certain Issues*, addressing the ratemaking treatment for annual  
29 other post-employment benefit costs (also known as “OPEBs”) under Financial Accounting  
30 Standard No. 106 (“FAS 106”). OPEBs primarily relate to medical benefits owed by Empire to  
31 Company retirees. The 2006 agreement was later modified by the *Stipulation and Agreement as*

1 to *Certain Issues* reached in Case No. ER-2008-0093, ER-2010-0130, ER-2011-0004,  
2 ER-2012-0345, and ER-2014-0351. (Collectively, Staff will refer to the *Stipulations and*  
3 *Agreements* regarding OPEB expense ratemaking from the 2006 rate case to current as the  
4 “OPEB Agreements.”) These OPEB Agreements were intended to ensure that the amount  
5 collected in rates for OPEBs were based on the FAS 106 cost recognized by the Company for  
6 financial reporting purposes, using a methodology similar to that used to determine FAS 87  
7 pension cost. In addition, the OPEB Agreements were intended to ensure that Empire  
8 contributed the full amount of the OPEB expenses it collected in rates into an external trust fund.  
9 The OPEB Agreements also called for the use of a OPEBs tracker mechanism to quantify the  
10 difference over time in the OPEBs rate allowance provided to the Company, and the Company’s  
11 annual actual OPEBs expenses under FAS 106.

12 In this case, Staff has complied with the terms agreed upon by the signatories to OPEB  
13 Agreements approved by the Commission in Empire’s last six electric rate cases for ratemaking  
14 treatment of OPEBs costs. Empire’s OPEB costs in this case were based upon the Company’s  
15 actuary report, Exhibit 3 of Empire’s 2015 OPEB expense and workpapers. Staff will update the  
16 OPEB costs, tracker balance and amortization in its True-Up testimony. The results of Staff’s  
17 review of Empire’s OPEB costs are as follows:

- 18 1. The Company’s ongoing FAS 106 cost recognized in rates in this  
19 case is \$2,731,018.
- 20 2. Empire has over-recovered its FAS 106 expense in rates compared  
21 to its actual level of expense since the Company’s last rate case.  
22 The balance in the Regulatory Liability account as of September  
23 30, 2015, was (\$819,451), which is to be amortized over five years  
24 as a reduction to expense in the amount of (\$163,890).
- 25 3. Rate base is reduced by the level of regulatory liability associated  
26 with Empire’s ongoing OPEBs tracker mechanism, \$819,451 as  
27 noted above.

28 *Staff Expert/Witness: Paul R. Harrison*

## 29 **6. Supplemental Executive Retirement Plan (“SERP”)**

30 Certain management employees receive benefits under Empire’s Supplemental Employee  
31 Retirement Program (“SERP”). The provisions of FAS 87 are used to calculate the annual  
32 financial reporting expense accrual for this plan. Due to the fact that the benefits from this

1 retirement program are not available to a broad range of employees, the Internal Revenue  
2 Service (“IRS”) designates this program as a “non-qualified” plan. In a non-qualified plan, the  
3 expense is not “pre-funded” and only the amounts paid to beneficiaries are tax deductible.  
4 Therefore, Staff’s policy has been to limit utilities’ rate recovery of this item to actual benefit  
5 payments to employees, if reasonable. Staff used the five-year average ending September 30,  
6 2015, of actual payments made to determine the annual cost of the SERP for inclusion in rates  
7 for this case.

8  
9 *Staff Expert/Witness: Paul R. Harrison*

## 10 **G. Maintenance Normalization Adjustments**

11 Empire’s maintenance expenses for its generating facilities (production stations) tend to  
12 fluctuate from year to year, since unscheduled outages occur at irregular and unpredictable times,  
13 and major planned outages do not occur annually. Each maintenance account was reviewed and  
14 analyzed separately for each production station. The production facilities examined included  
15 Iatan 1, Iatan 2, Iatan Common, Asbury, Riverton, State Line Combined Cycle, State Line 1,  
16 Energy Center, Ozark Beach, and Plum Point. These units were examined individually because  
17 each of them is on a different maintenance cycle and to group them would have either overstated  
18 or understated the final annualized maintenance costs. These adjustments were then combined  
19 where possible in an effort to reduce the volume of adjustments.

20 The Staff’s proposed production maintenance normalization adjustments pertain to  
21 Empire’s non-labor maintenance costs only; labor maintenance costs are handled as part of the  
22 Staff’s overall payroll adjustments.

### 23 **1. Iatan 1**

24 Staff noted the Iatan 1 production station is on a six-year major maintenance cycle.  
25 For that reason, Staff used a six-year average of maintenance costs to develop its adjustment for  
26 Iatan 1 maintenance expense. Empire owns only 12% of the Iatan 1 unit.

### 27 **2. Asbury**

28 The Asbury maintenance expense is based on a five-year overhaul schedule of the boiler  
29 and turbine. Staff’s adjustment is based upon a five-year average of maintenance costs.

1                                   **3. Riverton (Excluding Riverton Unit 12)**

2                   The Riverton maintenance expense is based on a five-year overhaul schedule of the boiler  
3 and turbine. Staff’s adjustment is based upon a five-year average of maintenance costs.

4                                   **4. State Line Combined Cycle (“SLCC”) and State Line Common**

5                   The SLCC maintenance expense is based on a five-year overhaul schedule of the  
6 boiler and turbine. Empire owns 60% of the SLCC unit, with Westar Energy (“Westar”) owning  
7 the remaining 40%. Staff subtracted 40% of SLCC expenses incurred in the period ended  
8 September 30, 2015, to adjust out Westar’s portion of test year expenses. Staff then applied an  
9 adjustment based on a five-year average of Empire’s portion of maintenance costs. Empire is  
10 responsible for 66.7% of the State Line Common maintenance expenses, while Westar Energy is  
11 responsible for the remaining 33.3%. Staff subtracted 33.3% of State Line Common expenses  
12 incurred in the test year amount, established in the last case ER-2014-0351, to adjust out  
13 Westar’s portion of test year expenses. Staff then applied an adjustment based on a five-year  
14 average of Empire’s portion of maintenance costs.

15                                   **5. State Line 1**

16                   Empire has had a contract with Siemens group, related to the maintenance of this  
17 production unit, since June 29, 2001. The terms of the contract require Siemens to conduct  
18 maintenance service for the turbines, which are required to run for a specified number of hours  
19 per year. If a turbine does not meet the annual hours requirement, a credit is due to Empire from  
20 Siemens and if the turbine exceeds the hours, then the Company incurs additional costs from  
21 Siemens. The nature of this expense varies greatly from year to year and, therefore, Staff is  
22 recommending using a five-year average to normalize this expense. Staff subtracts the actual test  
23 year amount, established in the last case ER-2014-0351, from the five-year average to derive  
24 Staff’s adjustment.

25                                   **6. Energy Center and Ozark Beach**

26                   The Energy Center and Ozark Beach maintenance expense is based on a five-year  
27 overhaul schedule of the boiler and turbine. Staff’s adjustment is based upon a five-year average  
28 of maintenance costs.

1                   **H. O&M Expenses for Iatan 2, Iatan Common, and Plum Point**

2                   Empire currently owns 12% of Iatan 2 and Iatan Common generating facilities and 7.52%  
3 of Plum Point. As of September 30, 2015, the end of the update period in this case, the Iatan 2  
4 and Plum Point units each had five (5) years of operating experience. Accordingly, Staff used a  
5 five (5) year average of actual O&M expenses pertaining to Iatan 2, Iatan Common, and Plum  
6 Point to determine the normalized level of these expenses.

7                   In Empire’s last general rate case proceeding, Case No. ER-2014-0351, the parties agreed  
8 to terminate the tracker mechanism that had previously been used for Iatan 2, Iatan Common,  
9 and Plum Point O&M expenses. It was agreed that this tracker would end on July 31, 2015.  
10 Therefore, in this case, Staff analyzed the Iatan 2, Iatan Common, and Plum Point O&M costs  
11 beginning September 30, 2014, through July 31, 2015. For this time period, Staff then calculated  
12 the total O&M costs, including only the accounts identified in the computation of the base  
13 tracker amounts established in Case No. ER-2012-0345. Base tracker amounts were identified  
14 for Iatan 2, Iatan Common, and Plum Point. Staff then compared the total O&M costs from  
15 September 30, 2014, through July 31, 2015, to the base tracker amounts to determine the  
16 associated regulatory asset or liability for each plant. These new base tracker amounts were  
17 added to the pre-existing unamortized balances already in rate base. Staff recommends a  
18 three-year amortization of the excess costs over the base amount be used to set rates in this case.  
19 These balances will be updated as part of the true-up audit in this case, No. ER-2016-0023.

20  
21 *Staff Expert/Witness: Jermaine Green*

22                   **I. Other Non-Labor Expenses**

23                   **1. Customer Deposit Interest Expense**

24                   See the discussion in Section VIII. H., Rate Base-Customer Deposits.

25  
26 *Staff Expert/Witness: Jennifer K. Grisham*

27                   **2. Property Tax Expense**

28                   Utility companies are required to file a valuation of their utility property with their  
29 respective taxing authorities at the beginning of each assessment year, which is January 1st.



1 Based on the information provided by the utility, the taxing authority will in turn send the  
2 company its “assessed values” for every category of the company’s property. The taxing  
3 authority will then issue to the utility company a property tax rate later in the year. The final step  
4 in the process is when the taxing authority issues a property tax bill to the company late in each  
5 calendar year with a “due date” of December 31<sup>st</sup>. The billed amount of property taxes is based  
6 on the property tax rate applied to the previously determined assessed values of the utility’s plant  
7 in service balances as of January 1st of the same year.

8 Staff determined its adjustment for property taxes by developing a property tax rate to be  
9 applied to total electric plant in service as of December 31, 2014. Staff used the Company’s  
10 property tax rate included in their filing in this case. This property tax rate was then applied to  
11 total electric plant in service on December 31, 2014, to arrive at annualized property taxes. The  
12 annualized property tax expense was then subtracted from the property tax expense starting point  
13 in this case to derive the adjustment.

14 One minor difference in property taxes for the current rate is the treatment of the Plum  
15 Point Generating Unit (“Plum Point”) located in Arkansas. The owners of the Plum Point unit,  
16 including Empire, have entered into an agreement with the City of Osceola, Arkansas;  
17 Mississippi County, Arkansas; Osceola School District No. 1 of Mississippi County, Arkansas;  
18 and Mississippi County Community College District of Arkansas, to make an annual Payment in  
19 Lieu of Taxes (“PILOT”) instead of paying property taxes on the Plum Point unit in the normal  
20 manner. A PILOT agreement allows the owners of the Plum Point unit to pay one flat amount of  
21 property taxes on the Plum Point unit for 30 years with the potential for an extension at the end  
22 of the 30-year term, regardless of any additions or retirements made to the unit since its  
23 in-service date. To appropriately calculate the overall property tax amount for Empire, the  
24 amount of Empire’s share of the Plum Point plant had to be subtracted from total plant in service  
25 so as not to be included in the development of the annualized property taxes. The set amount of  
26 PILOT taxes that Empire has agreed to pay for Plum Point was then added to the annualized  
27 property tax calculation to determine the total property tax adjustment.

28 Staff will update its recommended level of property taxes as part of the true-up audit in  
29 this proceeding.

30  
31 *Staff Expert/Witness: Ashley R. Sarver*

1                                 **3. Corporate Franchise Taxes**

2                 Prior to January 1, 2016, Empire paid a corporate franchise tax in order to conduct  
3 business in the State of Missouri. Staff applied an adjustment in the prior rate case No.  
4 ER-2014-0351 but with a 0% jurisdictional allocation factor the account (408.910) was set to  
5 zero. The State of Missouri eliminated the corporate franchise tax effective January 1, 2016.  
6 Therefore, Staff made no adjustment, leaving the account at zero.

7  
8 *Staff Expert/Witness: Keith D. Foster*

9                                 **4. Amortization Expenses**

10                                **a. Amortization of Electric Plant**

11                 Staff reviewed all of Empire’s amortization expense booked to Account 404000,  
12 Amortization-Limited Term Electric Plant. After reviewing this data, Staff made an adjustment  
13 to increase this expense to reflect the annualized amortization based on updated information  
14 through September 30, 2015 (as described earlier in Section VIII. F.).

15  
16 *Staff Expert/Witness: Jennifer K. Grisham*

17                                **b. Amortization of Stock Issuance Costs**

18                 Staff has reviewed the Company’s books and determined that the entire amount of the  
19 prior costs associated with issuance of common equity will be fully amortized prior to new rates  
20 being established in the current rate case. The issuance costs will be fully amortized as of  
21 April 2016. Therefore, the stock issuance expense amortizations have been eliminated from cost  
22 of service in this case.

23  
24 *Staff Expert/Witness: Ashley R. Sarver*

25                                **c. Amortization of Ice Storm Costs**

26                 Empire booked ice storm amortizations in account 593599 from the other states in which  
27 it operates. Therefore, Staff made an adjustment to eliminate the amortized amount of the ice  
28 storm amortizations from other states that were included in the starting point in this case.

29  
30 *Staff Expert/Witness: Jennifer K. Grisham*

1                                   **5. Iatan Carrying Costs Amortization**

2           Pursuant to earlier agreements, Empire deferred certain carrying costs (monthly debt and  
3 equity-derived carrying charges) and monthly depreciation for its Iatan 1 AQCS Account 182308  
4 - Iatan Deferred Carrying Costs, Iatan 2 Account 182332 - MO IatanII Df Chg ER-2010-0130,  
5 and Plum Point Account 182331 - MO PlumPt Df Chgs ER-2010-0130. This deferral of carrying  
6 costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments was authorized under previous  
7 agreements, approved by the Commission. In Empire’s Case No. ER-2012-0345, Staff  
8 recommended amortization of these carrying costs into cost of service using a composite  
9 amortization rate derived from dividing the total depreciation expense for each plant by the total  
10 plant balance for each plant. Staff used these composite rates and calculated amortization  
11 amounts of \$84,729 for Iatan 1 AQCS, \$44,828 for Iatan 2, and \$1,987 for Plum Point. Staff  
12 used the same amortization amounts in this case.

13  
14 *Staff Expert/Witness: Keith D. Foster*

15                                   **6. Demand Side Management**

16                                   **a. DSM Programs**

17           As part of Empire’s Experimental Regulatory Plan, approved in Case No. EO-2005-0263  
18 (“2005 Case”), Empire’s Customer Programs Collaborative (“CPC”) was ordered to include  
19 Staff, Public Counsel, Department of Natural Resources,<sup>72</sup> and other interested parties to advise  
20 Empire on the development, implementation, monitoring, and evaluation of demand response,  
21 energy efficiency, and affordability programs for Empire’s Missouri customers.

22           As stipulated in the 2005 Case, the effective date of the initial rates that reflect inclusion  
23 of the Iatan 2 investment on customer’s bills would terminate Empire’s Experimental Regulatory  
24 Plan. On June 15, 2011, Empire’s Experimental Regulatory Plan terminated as a result of the  
25 Commission’s June 1, 2011, *Order Approving Global Agreement* (“2011 Order”) in Case No.  
26 ER-2011-0004. Also as a result of the 2011 Order, Empire’s CPC was terminated and the  
27 Demand-Side Management (“DSM”) Advisory Group was created.

---

<sup>72</sup> Now the Missouri Department of Economic Development – Division of Energy.

1 In Empire’s last general rate case, Case No. ER-2014-0351, the Commission ordered<sup>73</sup>  
2 that, “With the exception of the low-income weatherization program discussed below, ... Empire  
3 will continue its current energy efficiency programs, at current funding levels and with the  
4 current recovery mechanism, until Empire has an approved MEEIA<sup>74</sup> or until the effective date  
5 of rates in Empire’s next general rate case.”

6 Schedule BJJ-d1 contains annual actual expenditures, budgets, and variances from  
7 budget for each of Empire’s DSM programs for each of the past five (5) years. While six of  
8 Empire’s seven DSM programs consistently under-perform when it comes to spending their  
9 annual budget and reaching annual energy and demand savings targets, respectively, the  
10 Commercial & Industrial Facility Rebate Program<sup>75</sup> (“C&I Program”) overspends. The current  
11 quarterly funding level for the C&I Program is \$103,500, with the total annual funding level  
12 equal to \$414,000. However, for its C&I Program in 2015, Empire actually spent \$225,765 in  
13 the first quarter, \$187,714 in the second quarter, \$305,359 in the third quarter, and \$218,588 in  
14 the fourth quarter, for an annual total of \$937,425 spent. This overspend of \$523,425 for 2015 is  
15 primarily due to the flood of applications that Empire received for projects from trade allies  
16 taking advantage of the relatively high incentive Empire offers in its C&I Program. Empire’s  
17 C&I Program incentive is based on a buy down to the lesser of a two (2) year payback or fifty  
18 percent (50%) of incremental costs. There has not been any independent evaluation,  
19 measurement and verification (“EM&V”) of the C&I Program since 2009; there has never been a  
20 net-to-gross evaluation of the program.

21 Staff has reviewed Empire’s DSM Programs tariff sheets. Upon review, Staff found  
22 numerous instances of outdated and incorrect information within Empire’s DSM programs tariff  
23 sheets including: (1) multiple references to the CPC; (2) a reference to the website and  
24 sponsorship of the Missouri Department of Natural Resources for the Home Performance with  
25 ENERGY STAR® program; (3) program year and budget displayed only up through 2013;  
26 (4) references to “the end of 2014” that are no longer relevant, etc.

27  
28 *Staff Expert/Witness: Brad J. Fortson*

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<sup>73</sup> *Report and Order* filed June 24, 2015.

<sup>74</sup> Missouri Energy Efficiency Investment Act.

<sup>75</sup> The Empire District Electric Company, P. S. C. Mo. No. 5, Section 4, 3<sup>rd</sup> Revised Sheet No. 8a.

1                                   **b. DSM Cost Recovery**

2            Empire’s Account 182318 contains costs of the Company’s DSM programs that are in  
3 various stages of development and implementation. Staff participated in the previously  
4 authorized (and now expired) Customer Programs Collaborative (“CPC”) and participates in the  
5 current authorized DSM advisory group established to assist Empire in the development of DSM  
6 programs. Based upon Staff’s participation in these groups, as well as Staff’s review of the costs  
7 in Account 182318, Staff has amortized the amounts incurred by Empire prior to the end of the  
8 its Regulatory Plan (June 15, 2011) over ten years and any amounts incurred after the end of the  
9 Regulatory Plan to date are amortized over a period of six years, consistent with the terms of the  
10 Commission’s *Report and Order* in Case No. ER-2014-0351. Staff has removed the program  
11 expenditures from 2005 and 2006 since they will be expiring on December 31, 2016. The DSM  
12 costs include the payments to Empire’s customers that participate in the programs.

13  
14 *Staff Expert/Witness: Ashley R. Sarver*

15                                   **c. Chapter 22 Electric Utility Resource Planning**

16            On April 1, 2016, Empire’s electric utility resource planning triennial compliance filing<sup>76</sup>  
17 will be filed with the Commission. The triennial compliance filing will play a key role in  
18 understanding Empire’s long-term DSM strategy and whether the strategy will provide benefits  
19 for all customers.<sup>77</sup> Staff will review Empire’s triennial compliance filing and may make  
20 specific recommendations concerning current DSM programs in rebuttal testimony to this case.

21  
22 *Staff Expert/Witness: Brad J. Fortson*

23                                   **d. MEEIA Filings**

24            Empire filed its first MEEIA application on February 28, 2012, in File No.  
25 EO-2012-0206 and withdrew it on July 5, 2012. Empire filed a subsequent MEEIA application  
26 on October 29, 2013, in File No. EO-2014-0030; however, the procedural schedule was  
27 suspended on January 14, 2014, to allow additional time for technical conferences and settlement  
28 discussions. However, on July 24, 2015, Empire filed *Empire’s Motion to Withdraw its MEEIA*

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<sup>76</sup> 4 CSR 240-22.080(1) Filing Schedule, Filing Requirements, and Stakeholder Process.

<sup>77</sup> Section 393.1075.4 of the MEEIA statute.

1 *Application and Request for this Docket to be Closed.* On August 13, 2015, the Commission  
2 filed a *Notice of Dismissal* and the case was dismissed. To date, Empire has not filed another  
3 MEEIA application.

4  
5 *Staff Expert/Witness: Brad J. Fortson*

6 **7. Low Income Programs**

7 Empire currently has a program called Low-Income New Homes which works with local  
8 non-profit organizations, such as the Habitat for Humanity and local government community  
9 development organizations to provide financial incentives for increased energy efficiency in the  
10 building shell insulation and for high-efficiency central air conditioners, heat pumps,  
11 refrigerators and lighting fixtures.

12 In addition to the Low-Income New Homes program, Empire also offers other programs  
13 to assist the elderly and disabled. The first program is entitled Empire’s Action to Support the  
14 Elderly (“EASE”). EASE allows Empire to wave late penalties and deposits, adjust due dates  
15 and notify third parties when an account becomes delinquent. Finally, Empire jointly works with  
16 Crosslines Churches in Joplin and the voluntary donations of customers to offer Project Help.  
17 Project Help is an assistance program created to meet emergency energy-related expenses of the  
18 elderly and/or disabled residents in Empire’s electric service area.

19 Staff has reviewed the programs and is not aware of any issues that need to be addressed  
20 in this case.

21  
22 *Staff Expert/Witness: Kory Boustead*

23 **a. Low Income Weatherization**

24 The State of Missouri Low-Income Weatherization Assistance Program (“LIWAP”) is  
25 administered by the Missouri Department of Economic Development, Division of Energy  
26 (“DED-DE”) using federal, state, and utility funding. The DED-DE low-income weatherization  
27 program is administered locally by Community Action Agencies or other local agencies  
28 (“Weatherization Agencies”). The total amount of grants offered to a customer and customer  
29 eligibility is determined by federal LIWAP guidelines published by the U.S. Department of

1 Energy (“USDOE”). The funding focuses on measures that reduce electricity usage associated  
2 with electric heat, air conditioning, refrigeration, lighting, etc.

3 Empire began providing supplemental funding for the State of Missouri’s federally  
4 funded LIWAP, subjected to the USDOE guidelines, as part of the *Stipulation and Agreement* in  
5 Case No. ER-2004-0570. Empire participates in a Demand Side Management Advisory Group  
6 (“DSMAG”), composed of the Public Service Commission Staff, the Office of the Public  
7 Counsel, DED-DE, and others to oversee the allocation of funds and review annual reports  
8 provided by Empire and the Weatherization Agencies, consisting of:

- 9 a) Program funds provided by Empire.
- 10 b) Amount of Program funds, if any, rolled over from previous year.
- 11 c) Amount of administrative funds retained by the social agency.
- 12 d) Number of weatherization jobs completed and total cost (excluding  
13 administrative costs).
- 14 e) Number of weatherization jobs “in progress” at the end of the calendar year.
- 15 f) Number, type, and total cost of baseload measures (non-heating) installed.

16 Per Empire’s Sixth Revised Tariff Sheet 8c, they are required to allocate the funds in accordance  
17 with an established formula. The formula, calculated by the Division of Energy, allocates the  
18 dollars between the weatherization agencies based on the total Empire accounts enrolled with a  
19 weatherization agency and the percentage of households in poverty within the agency’s service  
20 region. This funding is used to help with repairs needed to allow the home to meet the eligibility  
21 criteria so the LIWAP funding can be used to weatherize the home.

22 Staff supports the supplemental funding of the LIWAP because programs of this nature  
23 have a positive impact on the ability of low-income customers to pay their energy bills, which in  
24 turn reduces a utility company’s amount of arrearages. Additionally, Staff recognizes that the  
25 LIWAP can also improve the safety and comfort level of a home while reducing energy usage.  
26 The LIWAP works with Community Action Agencies to assist customers through conservation,  
27 education and weatherization to reduce their use of energy; thus reducing the level of bad debts  
28 experienced by Empire. Therefore, Staff recognizes that LIWAP programs promote public  
29 policies beyond a demand-side resource program. Most electric and natural gas regulated  
30 utilities provide supplemental funding for low-income weatherization. Four utilities in

1 Missouri<sup>78</sup> provide funds to the Environmental Improvement and Energy Resources Authority  
2 (“EIERA”) which are administered to the Weatherization Agencies similar to the USDOE funds.

3 Empire’s last evaluation of the Low-Income Weatherization program was completed in  
4 2009. There have been funding level changes to the program since 2009. Through the American  
5 Recovery and Reinvestment Act (“ARRA”), special federal funding of \$128 million was  
6 provided for the DED-DE Weatherization Program for the period of April 2009 – March 2013  
7 (“ARRA Period”). The ARRA provided an average of \$6,500 of weatherization for households  
8 with income at 200% or less of the Federal Poverty Guidelines (“FPG”). In the three-year period  
9 (2006-2008) prior to the ARRA Period, federal funding for the DED-DE Weatherization  
10 Program was approximately \$18 million and the average amount of weatherization per  
11 household was \$3,000.

12 Due to these changes, Staff recommends that Empire perform another evaluation of the  
13 Low-Income Weatherization Assistance program. In order to get a better picture of the full  
14 impact of weatherization on low-income homes, Staff recommends that the evaluation include a  
15 representative sample of homes that use both electricity and natural gas for space conditioning.  
16 This sample should include homes served by Missouri Gas Energy (“MGE”) a division of  
17 Laclede Corporation, provided that Empire can obtain the information necessary to determine  
18 cost effectiveness from MGE. In order to facilitate the evaluation process, Staff recommends  
19 that Empire invite MGE to one or more of the DSMAG meetings to discuss the evaluation and  
20 the potential of providing the evaluator with a customer’s natural gas information.

21  
22 *Staff Expert/Witness: Kory Boustead*

## 23 **8. Current and Deferred Income Tax**

### 24 **a. Current Income Taxes**

25 Current income tax for this case has been calculated by Staff largely consistent with the  
26 methodology used in Empire’s most recent rate case, Case No. ER-2014-0351. Adjustments are  
27 made to net income to compute the current income tax expense. These adjustments are  
28 effectuated by taking adjusted net income and either adding to or subtracting from the net  
29 income various timing differences to obtain net taxable income for ratemaking purposes.

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<sup>78</sup> Laclede Natural Gas, Ameren Missouri (electric and natural gas) and Liberty Utilities



1 (The term “timing differences” refers to the differences in time when certain costs can be  
2 deducted for purposes of determining financial statement net income and taxable income,  
3 respectively.) The adjustments are the result of various financial statement (“book”) and tax  
4 timing differences as well as their implementation under separate tax ratemaking methods:  
5 flow-through versus normalization. The resulting net taxable income for ratemaking is then  
6 multiplied by the appropriate federal and state tax rates to obtain the current provision for  
7 income taxes. Staff used the current federal tax rate of 35 percent and the current state income  
8 tax rate of 6.25 percent in calculating Empire’s income tax liability. The composite tax rate,  
9 taking into account both federal and state income tax rates, is 38.39%. The difference between  
10 the calculated current income tax provision and the per book income tax provision is the current  
11 income tax provision adjustment.

12 The tax timing differences used in calculating taxable income for computing current  
13 income tax are as follows:

14 Add Back to Operating Income Before Taxes:

15 Book Depreciation Expense

16 Non-Deductible Expense – Non-deductible meals and dues

17 Contributions In Aid of Construction

18 Book Amortization

19 Subtractions from Operating Income:

20 Interest Expense – Weighted Cost of Debt X Rate Base

21 Tax Depreciation – Straight-Line

22 Tax Depreciation – Excess

23 \*\*

24 \_\_\_\_\_ \*\* Thus Staff has made a deduction to net income before taxes to zero out current  
25 income tax expense and transfer the amount to deferred income tax expense.

26  
27 *Staff Expert/Witness: Amanda C. McMellen*

28 **b. Deferred Income Taxes**

29 When a tax timing difference is reflected for ratemaking purposes in the deferred tax  
30 adjustment consistent with the timing used in determining taxable income for the calculation of  
31 current income tax payable to the IRS, the timing difference is given a “flow-through” treatment.

1           When a current year timing difference is deferred and recognized for ratemaking  
2 purposes consistent with the timing used in calculating pre-tax operating income in the  
3 financial statements, then that timing difference is given “normalization” treatment for  
4 ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax  
5 impact of “normalizing” tax timing differences for ratemaking purposes. Current IRS rules for  
6 regulated utilities, in effect, require normalization treatment for the timing difference related to  
7 accelerated depreciation.

8           For most utilities, it is necessary to break out a utility’s tax depreciation into two separate  
9 components: tax straight-line depreciation and excess tax depreciation. Tax straight-line  
10 depreciation is different from book straight-line depreciation due to the different tax basis of  
11 property allowed under the tax code. Excess tax depreciation differs from straight-line book  
12 depreciation due to the higher depreciation rates allowed in the early years of an asset’s life  
13 under the current tax code as compared to “straight-line” book depreciation rates. To calculate  
14 excess tax depreciation, Staff used the total tax depreciation amount included in the Company’s  
15 filing in this case. Most tax basis differences were eliminated for assets placed into service after  
16 1986 due to the Tax Reform Act (“TRA”) enacted that year.

17           Staff’s deferred income tax adjustment in this rate case consists of three components:

- 18           1. Depreciation tax timing difference: the difference between tax  
19 straight-line depreciation expense and tax depreciation expense. Staff has  
20 normalized this difference consistent with the treatment of this item in past  
21 Empire rate proceedings.
- 22           2. Other IRS timing differences: contributions in aid of construction.  
23 This amount is normalized consistent with Staff’s calculation in the prior  
24 rate case filing.
- 25           3. Excess deferred income taxes resulting from the 1986 Tax Reform  
26 Act (“TRA”): Enactment of the TRA, which reduced the corporate  
27 income tax rates applicable to utilities, created excess deferred tax  
28 amounts associated with prior depreciation timing differences. As such,  
29 Staff uses an amortization to return excess deferred taxes resulting from  
30 the change in tax rates back to Empire’s customers.

31 *Staff Expert/Witness: Amanda C. McMellen*

1                                   **9. Insurance Expense**

2           Insurance expense is the cost of protection obtained from third parties by utilities  
3 against the risk of financial loss associated with unanticipated events or occurrences. Utilities,  
4 like non-regulated entities, routinely incur insurance expense in order to minimize their  
5 liability (and, potentially, that of their customers) associated with unanticipated losses.  
6 Staff made an adjustment to annualize Empire’s insurance expense to reflect the premiums paid  
7 as of September 30, 2015, the end of the update period.

8  
9     *Staff Expert/Witness: Jennifer K. Grisham*

10                                   **10. Bad Debt Expense**

11           Bad debt, or uncollectible expense, is the portion of retail revenue that Empire is unable  
12 to collect from retail customers due to non-payment of bills. After a certain amount of time has  
13 passed, Empire’s delinquent customer accounts are written off and turned over for collection.  
14 Empire and its collection agencies have been successful in collecting some portion of the  
15 delinquent amounts owed from customers even after they are written-off.

16           Staff examined the most recent five-year (October 2010 – September 2015) history of  
17 Empire’s bad debt write-offs that were never collected (i.e., write-offs net of amounts  
18 subsequently collected). It is apparent from a review of this data that Empire’s bad debt expense  
19 fluctuates from one year to the next. Therefore, Staff calculated a five-year average of the  
20 uncollectable percentage of bad debt to revenue, which was then applied to Staff’s annualized  
21 and adjusted level of test year retail rate revenues to obtain the normalized level of bad debt  
22 expense.

23  
24     *Staff Expert/Witness: Ashley R. Sarver*

25                                   **11. Postage**

26           Staff adjusted postage expense to reflect the annualized amount of postage through the  
27 end of the update period, September 30, 2015.

28  
29     *Staff Expert/Witness: Jennifer K. Grisham*

1 **12. PSC Assessment and Rate Case Expense**

2 **a. PSC Assessment**

3 The adjustment represents the difference between the Staff’s annualized PSC Assessment  
4 and the amount included in the starting point in this case. The most recent PSC Assessment, in  
5 effect for the fiscal year July 1, 2015, to June 30, 2016, was used in the Staff’s annualization.

6  
7 *Staff Expert/Witness: Jennifer K. Grisham*

8 **b. Rate Case Expense**

9 **i. Normalization**

10 Staff reviewed Empire’s rate case expense related to this case for the reasonableness  
11 and prudence of all services secured and all costs incurred. Staff included the actual costs  
12 incurred by Empire for rate case expense as of February 29, 2016, directly related to this case  
13 (No. ER-2016-0023). Staff’s rate case expense adjustment is based upon all costs associated with  
14 filing and bringing this case before the Commission such as consulting fees, employee travel  
15 expenditures, and legal representation. Staff has normalized the rate case expense over a three  
16 (3) year period. The ultimate amount of rate case expense incurred by the Company in this  
17 proceeding will be directly associated with the length of the case through the settlement  
18 conference and hearing process.

19 The Company’s depreciation study, which was submitted as part of this rate case, fulfills  
20 the requirement to perform a study every five (5) years. Therefore, this cost is being normalized  
21 over a five-year period.

22 The Company also performed a line loss study as a part of this rate case. According to the  
23 Missouri Code of State Regulations (CSR) 4 CSR 240-20.090(9), the electric utility shall  
24 conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on  
25 a schedule that permits the study to be used in the general rate proceeding necessary for the  
26 electric utility to continue to utilize rate adjustment mechanism. Staff is normalizing this cost  
27 over a four-year period.

1 Rate case expense will also be examined in the true-up portion of this case. Accordingly,  
2 Staff will continue to examine the actual costs incurred by Empire relating to the processing of  
3 the rate case and include all prudently incurred expenses in the cost of service analysis.

4  
5 *Staff Expert/Witness: Ashley R. Sarver*

6 **ii. Sharing Recommendation**

7 In the *Staff Investigative Report on Rate Case Expense* (“Report”) filed in Case No.  
8 AW-2011-0330 in September 2013, Staff made certain recommendations regarding ongoing rate  
9 recovery policies for utility rate case expense. Within the Report, Staff asserted that rate case  
10 expense provides a benefit to both utilities and customers. Staff noted that a practice of granting  
11 utilities full recovery of incurred rate case expense does not provide the utility with strong  
12 incentives to reasonably limit their expenditures in this area. Staff also expressed concerns in the  
13 Report that full rate recovery of incurred rate case expense gives a utility an inappropriate  
14 financial advantage over other parties and interveners in rate case which must operate with  
15 budgetary and other financial restrictions. It was Staff’s conclusion in the Report that the  
16 application of “structural incentives” to rate case expense recovery be considered by the  
17 Commission in order to acknowledge the dual-beneficiary nature of rate case expense  
18 incurrence, alleviate a utility’s advantage over other parties in a rate case, and to incentivize a  
19 utility to file a “tight” case that is easier to process.

20 One option mentioned by Staff in the Report to accomplish the above-stated goals was  
21 for rate case expense to be shared between ratepayers and shareholders according to the  
22 percentage of a utility’s rate increase request that is ultimately determined to be just and  
23 reasonable by the Commission. This is the mechanism that Staff recommends be employed in  
24 this rate case to normalize rate case expense. This sharing mechanism assigns to ratepayers costs  
25 that are reasonable and from which ratepayers receive a benefit, and only those costs; it reduces  
26 the Company’s significant financial advantage over other participants in the rate case process;  
27 and it provides an incentive for the Company to control its costs.

28 The Commission recently provided specific guidance on this issue in its *Report and*  
29 *Order* in **Re: Kansas City Power & Light**, Case No. ER-2014-0370, which referenced the  
30 aforementioned Staff Report. In its decision, on page 72 of Order, the Commission stated the  
31 following:

1 The Commission finds that in order to set just and reasonable rates  
2 under the facts in this case, the Commission will require KCPL  
3 shareholders to cover a portion of KCPL's rate case expense. One  
4 method to encourage KCPL to limit its rate case expenditures  
5 would be to link KCPL's percentage of recovery of rate case  
6 expense to the percentage of its rate case request the Commission  
7 finds just and reasonable.<sup>[79]</sup> The Commission determines that this  
8 approach would directly link KCPL's recovery of rate case  
9 expense to both the reasonableness of its issue positions and the  
10 dollar value sought from customers in the this rate case.<sup>[80]</sup>

11 The Commission concludes that KCPL should receive rate  
12 recovery of its rate case expense in proportion to the amount of  
13 revenue requirement it is granted as a result of this Report and  
14 Order, compared to the amount of its revenue requirement rate  
15 increase originally requested.

16 After reviewing the evidence and circumstances of Empire's current ER-2016-0023 rate case,  
17 Staff recommends that rate case expense be shared between Empire ratepayers and shareholders  
18 by the same method suggested in the Staff Report issued in Case No. AW-2011-0330, and  
19 ordered by the Commission in the recent KCPL rate case, Case No. ER-2014-0370. Staff  
20 recommends the percentage of rate case expense which is to be borne by the ratepayers be equal  
21 to the percentage of its rate increase request that is determined to be just and reasonable.  
22 Ultimately, this will be the percentage of the Company's rate increase request that is granted by  
23 the Commission. For its direct filing, Staff calculated a percentage based on Staff's current  
24 revenue requirement recommendation compared to the amount Empire requested in this case.  
25 Then, that percentage was applied to the actual rate case expenses incurred to date and  
26 normalized over three (3) years. This calculation will be updated throughout the case. Staff  
27 recommends that the depreciation study and line loss study be exempt from the application of the  
28 recommended sharing percentage and the recoverable over the years stated above.

29  
30 *Staff Expert/Witness: Amanda C. McMellen*

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<sup>79</sup> This method can be expressed as: (Revenue Requirement Approved / Original Revenue Requirement Requested) X 100 = allowable percentage of rate case expense.

<sup>80</sup> It is understood that some of the issues litigated in this case do not directly affect the overall revenue requirement granted by the Commission; but it is clear that the vast majority of the litigated issues do have a direct or indirect impact on the revenue requirement. Accordingly, percentage sharing is a reasonable approach to correlating recovery of rate case expense to the relationship between the amount of litigation that benefited both ratepayers and shareholders and that which benefited only shareholders.

1 **13. Injuries and Damages and Workers' Compensation**

2 Empire maintains workers' compensation insurance for the benefit of its employees.  
3 The workers' compensation adjustment proposed by Staff annualizes this expense based upon  
4 the premiums in effect at September 2015 to reflect an ongoing and normal expense level for  
5 Empire.

6 From time to time, Empire is sued by claimants seeking payment of damages. If Empire  
7 loses the lawsuit, it is likely to be required to make a payout to the aggrieved party.  
8 Alternatively, it may choose to enter into an out-of-court settlement, also resulting in a payout.  
9 Based upon generally accepted accounting principles, Empire is required to charge to current  
10 expense an estimate of its future payouts for injuries and damages claims. To determine  
11 a normalized level of this expense, Staff used a five-year average of actual injuries  
12 and damages and workers' compensation payments in its cost of service report, instead of  
13 relying upon accounting estimates. Staff applied an allocation of 49.62 percent to the five-year  
14 average of actual payments made for injuries and damages. The allocation of 49.62 percent  
15 represents the electric expense portion of the payments. The remaining amounts of the payments  
16 (50.38%) are allocated to the Company's construction, water operations and below-the-line  
17 activities. A five-year average of actual payments was used to normalize this expense because  
18 Staff's analysis shows a considerable fluctuation in the annual amount of payments from one  
19 year to the next.

20  
21 *Staff Expert/Witness: Ashley R. Sarver*

22 **14. Advertising Expense**

23 Empire engaged in various advertising activities during the test year. In making its  
24 recommendation of the allowable level of Empire's advertising expense, Staff relied on the  
25 principles that the Commission determined were appropriate in the KCPL rate case, Case No.  
26 EO-85-185, *et al.*<sup>81</sup> Under these principles, the Commission recognizes five categories of  
27 advertisements, and specifies rate treatment based on each of the following categories:

- 28 1. General: informational advertising that is useful in the provision of  
29 adequate service;

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<sup>81</sup> *Re: Kansas City Power and Light Company*, 28 Mo. P.S.C. (N.S.) 228, 269-71 (1986).

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

The Commission applies this rationale by stating that a utility's revenue requirement should:

- 1) always include the reasonable and necessary cost of general and safety advertisements;
- 2) never include the cost of institutional or political advertisements; and
- 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement.

Following this guidance, Staff's starting point in this case includes adjustments excluding promotional and institutional advertising expenses from recovery in rates in the amount of \$155,394. No further adjustments were necessary for this case.

*Staff Expert/Witness: Amanda C. McMellen*

### **15. Outside Services**

Various outside (independent) contractors and vendors provide legal, auditing, and other services to Empire to carry out its operational activities as needed. Staff reviewed Empire's outside services expense booked to Accounts 923.045 and 923.047 for the test year through the update period ending September 30, 2015. Staff normalized the amounts of outside services on a going forward basis by calculating a five-year average of incurred costs for these accounts in the amount of \$2,448,464. This adjustment does not include outside services related to rate case expense. Outside services incurred for rate case purposes are booked in a separate account.

*Staff Expert/Witness: Keith D. Foster*

### **16. Dues and Donations**

Staff reviewed the list of membership dues paid and donations made to various organizations that Empire charged to its utility accounts during the test year. For the starting point in this case, Staff recommends adjustments to exclude various dues and donations that



1 were included by Empire in its above-the-line expense accounts. In *Re: Missouri Public*  
2 *Service, a Division of UtiliCorp United, Inc.*, Case Nos. ER-97-394, *et al.*, *Report and Order*,  
3 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

4           The Commission has traditionally disallowed donations such as  
5 these. The Commission finds nothing in the record to indicate any  
6 discernible ratepayer benefit results from the payment of these  
7 donations. The Commission agrees with the Staff in that  
8 membership in the various organizations involved in this issue is  
9 not necessary for the provision of safe and adequate service to the  
10 MPS ratepayers.

11 Staff excluded dues and donations that do not have any direct benefit to ratepayers and were not  
12 necessary for the provision of safe and adequate service. Allowing Empire to recover these  
13 expenses through rates causes the ratepayer to involuntarily contribute to these organizations.  
14 Examples of dues excluded from recovery in the rate case, based on the Commission's *Report*  
15 *and Order* mentioned above, are dues paid to the Home Builders Association, Rotary Club,  
16 and Twin Hills Golf and Country Club. An example of a donation that was excluded is  
17 donated merchandise purchased from Wal-Mart Inc. Area Chamber of Commerce dues were  
18 allowed, but National and State Chamber of Commerce dues were disallowed as being  
19 duplicative costs to the local Chamber of Commerce organizations. No further adjustments are  
20 necessary for this case.

21  
22 *Staff Expert/Witness: Amanda C. McMellen*

### 23 **17. Edison Electric Institute (“EEI”) Dues**

24           According to information obtained from the EEI website ([www.eei.org](http://www.eei.org)), EEI is an  
25 association of investor-owned electric utilities and industrial affiliates. In its review of EEI  
26 information, Staff determined that a primary function of EEI is to represent the interests of the  
27 electric utility industry in the legislative and regulatory arenas. This role includes EEI's  
28 engagement in lobbying activities.

29           In Case No. ER-83-49, a KCPL rate increase case, the Commission stated its  
30 determination that EEI dues:

31           ...would be excluded as an expense until the company could better  
32 quantify the benefit accruing to both the company's ratepayers and  
33 shareholders.

1 This position has been re-affirmed by the Commission in subsequent rate proceedings.

2 In *Re: Kansas City Power & Light Co.*, Case Nos. EO-85-185 *et al.*, *Report and Order*,  
3 28 Mo.P.S.C. (N.S.) 228, 259 (1986), the Commission stated:

4 . . . The argument that allocation is not necessary if the benefits  
5 lessen the cost of service to the ratepayers by more than the cost of  
6 the dues, misses the point.

7 It is not determinative that the quantification of benefits to the  
8 ratepayer is greater than the EEI dues themselves. The determining  
9 factor is what proportion of those benefits should be allocated to  
10 the ratepayer as opposed to the shareholder. It is obvious that the  
11 interests of the electric industry are not consistently the same as  
12 those of the ratepayers. The ratepayers should not be required to  
13 pay the entire amount of EEI dues if there is benefit accruing to the  
14 shareholders from EEI membership as well. The Commission  
15 finds this to be the case. The Company has been informed in prior  
16 rate cases that it must allocate its quantified benefits from  
17 membership in EEI. That has not been done herein. Therefore, no  
18 portion of EEI dues will be allowed in this case.

19 Empire failed to quantify ratepayer and shareholder benefits from its participation in EEI;  
20 therefore, the Staff removed total EEI dues included in the test year of \$147,299 from Empire's  
21 cost of service for the starting point in this case. No further adjustment is necessary for this case.

22  
23 *Staff Expert/Witness: Amanda C. McMellen*

#### 24 **18. Tree Trimming Expense/Infrastructure Inspection Expense**

25 In Case No. ER-2008-0093, the Commission authorized Empire to set up a two-way  
26 tracker mechanism to account for any difference between Empire's incurred vegetation  
27 management (i.e., tree trimming) and infrastructure inspection costs compared to an estimated  
28 target annual amount of \$8,575,000. While Staff and the Company agreed to continue the  
29 vegetation tracker beyond the 2008 rate case, the infrastructure tracker was eliminated on  
30 May 12, 2010, as per the *Non-Unanimous Stipulation and Agreement*, File No. ER-2010-0130.  
31 In the last rate case, File No. ER-2014-0351, Staff and the Company agreed to discontinue the  
32 vegetation tracker effective July 31, 2015, as stated in the *Non-Unanimous Stipulation and*  
33 *Agreement* filed in that proceeding. Additionally, in the last case, Staff accepted Empire's  
34 recommendation to reduce the ongoing amount of tree trimming expense from \$12 million

1 dollars to \$11 million dollars. In this current case, Staff updated the vegetation management  
2 tracker balance as of July 31, 2015, and will perform a true-up for the unamortized balance  
3 (*see* Section VIII. K.).

4 Staff adjusted the infrastructure inspection remediation cost incurred in this case. These  
5 remediation costs resulted from the Company performing preventive maintenance on its  
6 transmission and distribution system during the inspection cycles mandated under the  
7 infrastructure inspection rule. Staff reviewed the remediation costs incurred over the last five  
8 years ending December 31, 2014, and annualized the costs to increase the test year expense level  
9 in the amount of \$127,211.

10  
11 *Staff Expert/Witness: Jermaine Green*

#### 12 **19. SWPA Amortization**

13 As described previously in this Report, in Case No. ER-2011-0004, Empire agreed to  
14 flow the SWPA payment back to its customers over a ten-year period via a tracker mechanism.  
15 This yearly amortization, unlike other amortizations discussed in this Report, does not increase  
16 the Company's expense levels but is a reduction or offset to expenses. The starting point in this  
17 case reflects an appropriate amount of annual amortization expense. No further adjustments are  
18 necessary for this case.

19  
20 *Staff Expert/Witness: Amanda C. McMellen*

#### 21 **20. Lease Expense**

22 Lease costs are those costs incurred by Empire for the leasing of its equipment and  
23 building space. Staff submitted Data Request No. 0061 to Empire asking for a list of all lease  
24 agreements (office, vehicle, computers, etc.) charged to Missouri electric operations, along with  
25 the lease costs and information concerning all changes to the lease amounts since the since the  
26 last rate case, No. ER-2014-0351. Staff examined these costs for the test year, updated through  
27 September 30, 2015, and did not make an adjustment because there were no material differences  
28 since the last rate case.

29  
30 *Staff Expert/Witness: Ashley R. Sarver*

1                   **21. Solar Rebates**

2                   On May 5, 2015, Empire issued tariffs to establish solar rebate payments procedures, and  
3 to revise its net metering tariffs to accommodate the payment of solar rebates.<sup>82</sup> The tariff  
4 submitted under YE-2015-0322 became effective on May 16, 2015. Based upon staff’s review of  
5 the costs recorded to date in Account 182377, Staff has amortized the costs over a ten-year  
6 period. Staff is using the September 30, 2015, balance of this regulatory asset in rate base in this  
7 case. The Staff has also included an adjustment in the Income Statement to amortize these costs  
8 to expense. Staff will make further adjustments in the true-up audit in order to address any  
9 additional solar rebate spending through that point in time.

10  
11 *Staff Expert/Witness: Ashley R. Sarver*

12                   **22. Tornado AAO Amortization**

13                   The Commission issued an order on November 30, 2011, that approved and incorporated  
14 the *Stipulation and Agreement* in Empire’s *Application for an Accounting Authority Order*, Case  
15 No. EU-2011-0387. In that *Stipulation and Agreement*, the parties agreed to allow Empire to  
16 defer to Account 182.3 the following items: Other Regulatory Assets, incremental operations  
17 and maintenance expenses associated with the repair, restoration and rebuild activities associated  
18 with the May 22, 2011, tornado; and depreciation and carrying charges equal to its ongoing  
19 Allowance for Funds Used During Construction rates associated with tornado-related capital  
20 expenses. The Company agreed that if it filed a general rate case in Missouri by June 1, 2013,  
21 then Empire would begin to amortize over a ten-year period the deferral balance beginning at the  
22 earlier of: 1) the effective date of new rates implemented in its next general rate increase case or  
23 rate complaint case; or 2) June 1, 2013. As of September 30, 2015, Empire had a deferred  
24 balance of \$3,018,860 in Account 182.3 for tornado-related expenses. Staff has not included this  
25 balance in rate base because of the Commission’s long-standing policy of “sharing” the financial  
26 impact of extraordinary events, such as tornado expenses, through exclusion of the unamortized  
27 portion of an accounting authority order deferral from rate base the annual amortization  
28 calculated in last rate case, ER-2014-0351, has not changed. Therefore, Staff included the same  
29 annualized amount in this case.

30  
31 *Staff Expert/Witness: Amanda C. McMellen*

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<sup>82</sup> Order Approving Expedited Tariff, MoPSC File No. ET-2015-0285, page 1.

1                                    **23. Software Maintenance Expense**

2                    Empire has contracts, operating licenses, and agreements with vendors that provide  
3 maintenance, upgrades to software, and support for its computer software. Based on the General  
4 Ledger for the period of September 1, 2014, through the update period ending September 30,  
5 2015, the monthly rates for the majority of Empire’s software maintenance agreements increased  
6 since the last rate case. However, while there were no entries for one software maintenance  
7 vendor, Power Costs Inc. (“PCI”). Staff annualized the expense for each of the suppliers based  
8 on the current rate for each as recorded on the General Ledger at September 30, 2015, setting the  
9 PCI annualized amount to zero, resulting in an overall decrease in annualized software  
10 maintenance expense. Therefore, Staff made an adjustment of \$(169,589) in Account 921-  
11 Office Supplies and Account 923- Outside Services, to decrease the software maintenance  
12 expense to reflect the annualized amount of \$873,581 as of September 30, 2015. The software  
13 items that are included in these maintenance expenses are Triple Point INSSINC – Futrack,  
14 Intergraph GMS and OMS, Maximo User License (through Total Resource Management),  
15 Oracle PeopleSoft, and Power Plant & Budgeting.

16  
17 *Staff Expert/Witness: Keith D. Foster*

18                                    **24. Corporate Expenses**

19                    Due to Staff concerns with the reliability of Empire’s current approach of allocating its  
20 corporate costs to its electric, gas, water and non-regulated activities, certain adjustments have  
21 been proposed in this case. First, Empire is currently not allocating any Administrative and  
22 General (“A&G”) expenses to their water operations. Staff has made an adjustment to remove a  
23 portion of A&G expenses currently charged to electric operations in order to allocate the costs to  
24 water operations. Staff has also made an adjustment to remove a portion of costs related to  
25 EDI due to concerns about the methodology the currently uses to allocate common costs to  
26 non-regulated activities, as described in Section IX. A., Corporate Allocations.

27  
28 *Staff Expert/Witness: Amanda C. McMellen*

1                                    **25. Capitalized Depreciation**

2                    Expenses related to construction projects are accumulated in construction-work-in-  
3 progress accounts, and are only eligible to be included in rates subsequent to the completion of  
4 the project. The capitalized expenses include depreciation expense associated with assets used in  
5 construction such as power operated equipment and transportation equipment. Capitalized  
6 depreciation expenses must be subtracted from the total depreciation expense amount calculated  
7 by using Empire’s total plant-in-service balances in order to prevent double recovery. Therefore,  
8 Staff has deducted capitalized depreciation from its total depreciation expense in order to arrive  
9 at the amount of depreciation expense associated with O&M related functions.

10  
11 *Staff Expert/Witness: Amanda C. McMellen*

12 **XI. Fuel Adjustment Clause (“FAC”)**

13                    **A. Policy**

14                    In summary, Staff makes the following recommendations regarding Empire’s Fuel  
15 Adjustment Clause (“FAC”) to the Commission:

- 16                    1. Continue Empire’s FAC with modifications;  
17                    2. Include a revised Base Factor<sup>83</sup> in the FAC tariff sheets calculated from  
18                    the Base Energy Cost<sup>84</sup> that the Commission includes in the revenue  
19                    requirement upon which it sets Empire’s general rates in this case; and  
20                    3. Order Empire to continue to provide the additional information as part of  
21                    its monthly reports<sup>85</sup> as Empire agreed to do in the *Revised Stipulation*  
22                    *and Agreement* filed April 8, 2015, in Rate Case No. ER-2014-0351 and  
23                    has continued to provide in its monthly reports.

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<sup>83</sup> Base Factor is defined in Empire’s Original Tariff Sheet No. 171 as “BASE FACTOR (“BF”): The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case.

<sup>84</sup> Base Energy Cost is defined in Empire’s Original Revised Tariff Sheet No. 171 as “Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchased Power Adjustment (“FPA”) and include fuel costs incurred to support sales (“FC”) plus purchased power costs (“PP”) plus net emission costs (“E”) minus off-system sales revenues (“OSSR”) minus renewable energy credit revenue (“REC”).

<sup>85</sup> Monthly reports are required by 4 CSR 240-3.161(5).

1 At this time Staff does not have its estimate for the Base Factor for the FAC, but will provide it  
2 and a discussion on the calculation of the Base Factor when Staff files its Class Cost of  
3 Service/Rate Design Report on April 6, 2016. Staff will use the Base Energy Cost and the kWh  
4 at the generator from its fuel run to develop the Base Factor.

## 5 **B. History**

6 Senate Bill 179<sup>86</sup> (“SB 179”) was passed and enacted in 2005. It authorizes investor-  
7 owned electric utilities to file applications with the Commission requesting authority to make  
8 periodic rate adjustments outside of general electric rate proceedings for their prudently-incurred  
9 fuel and purchased power costs. SB 179 grants the Commission the authority to approve,  
10 modify, or reject the electric utility’s request. SB 179 also states that the rate schedules  
11 implementing these rate adjustments outside of the rate case may provide the electric utility with  
12 incentives to improve the efficiency and cost-effectiveness of its fuel and purchased power  
13 procurement activities.

14 Prior to the passage of SB 179, fuel and purchased power costs were estimated and  
15 included in the determination of the utility’s revenue requirement in general electric rate  
16 proceedings. If the electric utility managed its fuel and purchased power procurement activities  
17 in a manner that allowed it to reliably serve its customers at a cost lower than what was included  
18 in its revenue requirement in the general electric rate proceeding, all of the savings were retained  
19 by the electric utility. If actual fuel and purchased power costs were greater than the cost  
20 included in the revenue requirement in the general electric rate proceeding, the electric utility  
21 absorbed all of the increased cost.

22 The Commission first authorized a FAC for Empire in its *Report and Order* in Empire’s  
23 2008 rate case, Case No. ER-2008-0093, and approved FAC tariff sheets in that case with  
24 an effective date of September 1, 2008. In general rate cases Case Nos. ER-2010-0130,  
25 ER-2011-0004, ER-2012-0345, and ER-2014-0351, the Commission authorized continuation,  
26 with modifications, of Empire’s FAC. The primary features of Empire’s present FAC (tariff  
27 sheet numbers 17l through 17t) include:

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<sup>86</sup> Section 386.266, RSMo. 2010 Cum. Supp.

- Two 6-month accumulation periods: March through August and September through February;
- Two 6-month recovery periods: December through May and June through November;
- Fuel Adjustment Rate (“FAR”) filings semi-annually not later than April 1 and October 1;
- One Base Factor for all calendar months of the year;
- A 95%/5% sharing mechanism;
- FAR rates for individual service classifications adjusted for the two Empire service voltage levels, rounded to the nearest \$0.00001, and charged on each kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with a true-up amount being included in the determination of FAR for a subsequent recovery period.

Empire has made Fourteen FAR filings, File Nos.:

EO-2009-0349	ER-2010-0105	ER-2010-0275
ER-2011-0095	ER-2011-0320	ER-2012-0098
ER-2012-0326	ER-2013-0122	ER-2013-0442
ER-2014-0087	ER-2014-0264	ER-2015-0085
ER-2015-0247	ER-2016-0080	

The resulting changes to the Empire FARs ordered by the Commission are summarized in the **Continuation of FAC** section of this report. The Base Factor was originally set in Empire’s 2008 general rate case and was changed as a result of the negotiated settlements in Empire’s 2010, 2011, and 2012 general rate cases, and by *Commission Report and Order* in the 2014 general rate case.

Staff has filed five prudence review reports<sup>87</sup> (File Nos. EO-2010-0084, EO-2011-0285, EO-2013-0114, EO-2014-0057, and EO-2015-0214) concerning its review of the costs and revenues of the Company’s FAC and found no evidence of imprudent decisions by the Company’s management related to fuel, purchased power and net emission costs, off-system sales revenues and renewable energy credits revenues for the time periods reviewed.

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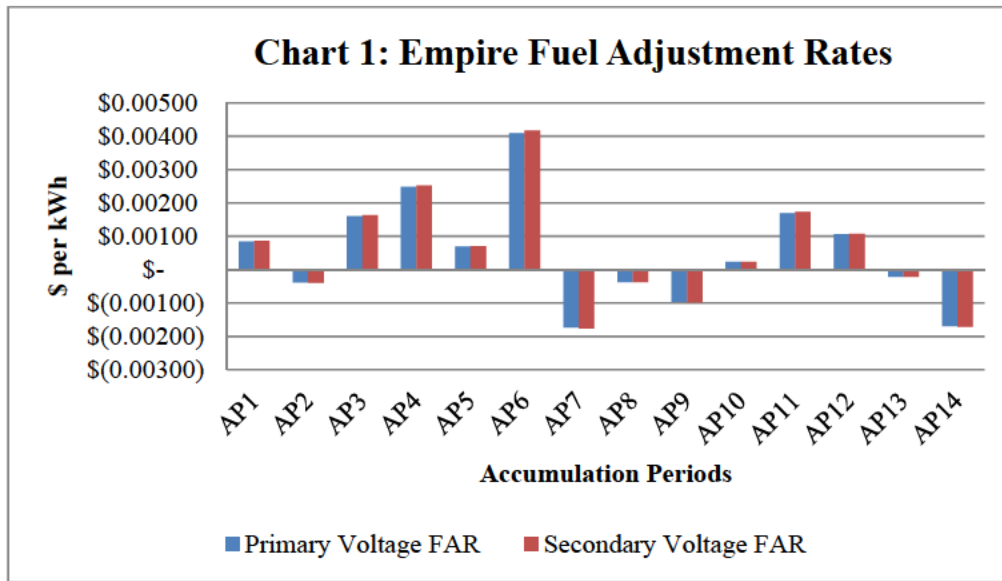
<sup>87</sup> 4 CSR 240-20.090(7) Prudence Reviews Respecting RAMs [rate adjustment mechanisms]. A prudence review of the costs subject to the RAM shall be conducted no less frequently than at eighteen (18)-month intervals.



**C. Continuation of FAC**

Staff recommends that the Commission approve, with modifications, the continuation of Empire’s FAC.

The Company has filed for and received approval of changes to its fuel adjustment rates (“FARs”) for fourteen (14) completed accumulation periods (“AP”) (AP1 through AP14). The primary and secondary voltage FARs for each accumulation period are reflected in Chart 1.



The time periods of the accumulation periods (“APs”) are as follows:

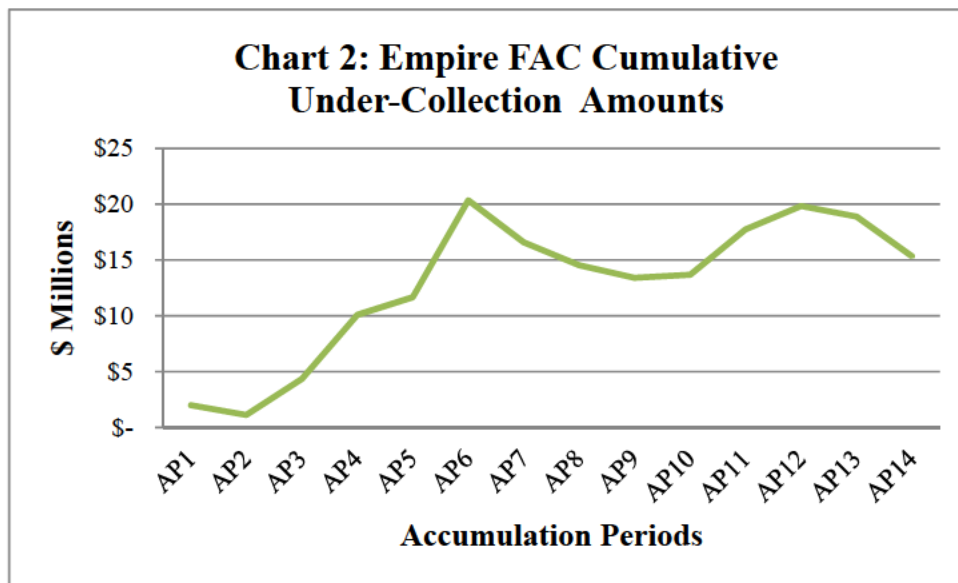
AP1 Sep 08 – Feb 09	AP2 Mar 09 – Aug 09
AP3 Sep 09 – Feb 10	AP4 Mar 10 – Aug 10
AP5 Sep 10 – Feb 11	AP6 Mar 11 – Aug 11
AP7 Sep 11 – Feb 12	AP8 Mar 12 – Aug 12
AP9 Sep 12 – Feb 13	AP10 Mar 13 – Aug 13
AP11 Sep 13 – Feb 14	AP12 Mar 14 – Aug 14
AP13 Sep 14 – Feb 15	AP14 Mar 14 – Aug 15

The Company’s actual Total Energy Cost have exceeded the then-effective Base Factors multiplied by monthly usage billed to Empire’s customers’ in eight out of fourteen completed accumulation periods. Actual Total Energy Cost include: Empire’s total booked costs as allocated to its Missouri retail jurisdiction for fuel consumed in the Company’s generating units, including the costs associated with the Company’s fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs; air

1 quality control system consumables, such as anhydrous ammonia, limestone, and powder  
 2 activated carbon, and emission allowance costs. Actual Total Energy Cost does not include the  
 3 purchased power demand costs, since these are considered to be fixed costs. Actual FAC costs  
 4 are off-set by actual Revenue from Off-System Sales, actual Net Emission Costs, and actual  
 5 Renewable Energy Credit Revenues. During six accumulation periods, AP2, AP7, AP8, and  
 6 AP9, AP13, and AP14, Empire’s Base Energy Cost exceeded actual Total Energy Cost; 95% of  
 7 such excess amounts were returned to customers during six recovery periods (“RP”) RP2, RP7,  
 8 RP8, RP9, RP13 and RP14. In eight of its accumulation periods (AP1, AP3, AP4, AP5, AP6,  
 9 AP10, AP11, and AP12), Empire under-collected its actual Total Energy Costs, and 95% of the  
 10 amounts of under-collection were recovered from Empire’s Missouri customers during recovery  
 11 periods RP1, RP3, RP4, RP5, RP6, RP10, RP11, and RP12.

12 At the conclusions of its general electric rate cases, during AP3, AP6, AP10, and AP14 –  
 13 Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2015-0351 respectively – the  
 14 Base Factors in Empire’s FAC were re-set.

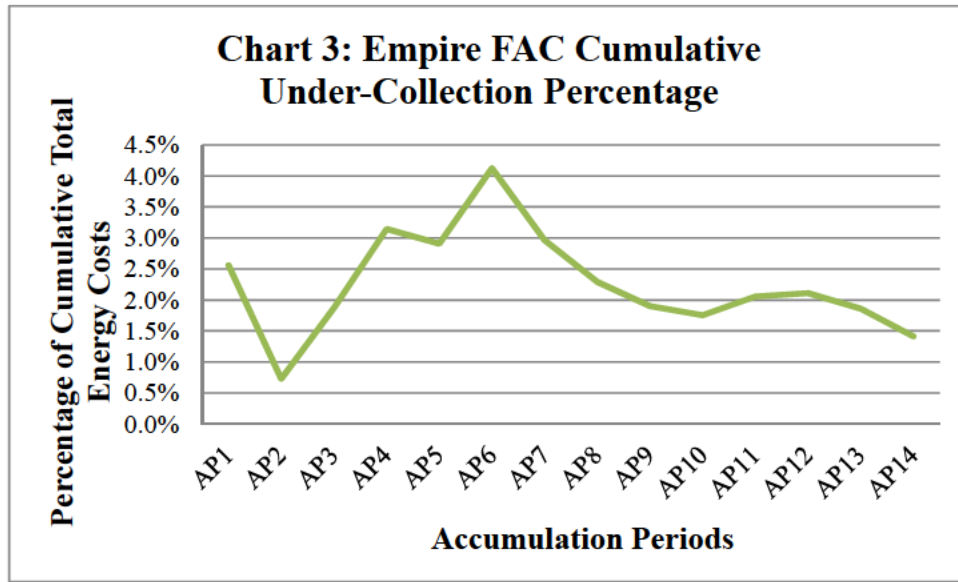
15 Charts 2 and 3 illustrate the following information for the first fourteen (14)  
 16 accumulation periods: 1) cumulative under collection amount which is equal to Total Energy  
 17 Cost (“TEC”) less Net Base Energy Cost (“B”) for Empire’s Missouri jurisdiction,<sup>88</sup> and  
 18 2) percentage of cumulative under-collection amount which is equal to  $100 * (TEC - B) / TEC$ .



20

<sup>88</sup> For AP14, this is the amount on line 5 of Empire’s 1<sup>st</sup> Revised Sheet No. 17t.

1



2

3 Chart 1 illustrates the variability of the FARs as a result of variations in each accumulation  
 4 period’s billed Base Energy Cost and actual Total Energy Cost. From Charts 2 and 3, Staff  
 5 observes that the FAC cumulative under-collected amount over eight years is approximately  
 6 \$15 million or about 1.4 percent of total actual Total Energy Cost of \$1,085 million during AP1  
 7 through AP14.

8 Staff recommends continuation of Empire’s FAC with modifications. As shown in the  
 9 previous charts and discussion, Empire’s actual Total Energy Costs continue to be relatively  
 10 large,<sup>89</sup> volatile, and beyond the control of the Company. In addition, the Southwest Power Pool  
 11 (“SPP”) conversion to the Integrated Marketplace (“IM”) on March 1, 2014, represents a  
 12 fundamental change in how Empire’s generation is dispatched and how Empire serves its native  
 13 load. By having an FAC that includes IM costs, the effects of the IM will flow through the FAC  
 14 to both the Company and its customers in a timely manner.

15 **D. Southwest Power Pool Integrated Market**

16 On February 1, 2007, SPP started the Energy Imbalance Services (“EIS”) Market when it  
 17 began dispatching wholesale electricity. The wholesale energy market is intended to allow for  
 18 more efficient deployment of generation across the SPP region through the establishment of an

---

<sup>89</sup> Empire’s proposed Base Energy Cost for this case represents 37% of the requested total revenue requirement.

1 offer-based market for energy imbalance services. The EIS Market was decommissioned  
2 March 11, 2014, following the start of the IM 10 days earlier, on March 1, 2014. The IM is a  
3 market expansion which added a market functionality that coordinates next-day generation  
4 across the region with the goals of maximizing cost-effectiveness, providing participants with  
5 greater access to reserve energy, improving regional balancing of electricity supply and demand,  
6 and facilitating the integration of renewable resources. Specifically, the Integrated Marketplace  
7 includes:

- 8 • A day-ahead market with transmission congestion rights (“TCRs”);
- 9 • A reliability unit commitment process;
- 10 • A real-time balancing market replacing SPP's EIS market;
- 11 • Incorporation of a price-based operating reserve market;
- 12 • Combining current balancing authorities into a single SPP balancing authority.

13 Empire is registered in the SPP IM as both a generating and load-serving entity. In the previous  
14 rate case, Case No. ER-2014-0351, Empire’s FAC tariff and the calculation of the FAC Base  
15 Factor were changed to reflect Empire’s participation in the SPP IM. Empire’s currently-  
16 approved FAC went into effect on July 26, 2015, and is structured to conform to the IM market.  
17 AP14 is the most recently completed accumulation period. One month of AP14, August 2015,  
18 was covered by the currently-approved FAC.

### 19 **E. Revising the Base Factor**

20 Correctly setting the Base Factor in Empire’s FAC tariff sheets is critical to both a well-  
21 functioning FAC and a well-functioning FAC sharing mechanism. For the reasons below, Staff  
22 recommends the Commission require the Base Factor in Empire’s FAC be set based on the Base  
23 Energy Cost that the Commission includes in the revenue requirement which it sets Empire’s  
24 general rates in this case.

25 Table 1 below shows three scenarios in which the FAC Base Energy Cost used to set the  
26 FAC Base Factor are equal to, less than, or greater than the Base Energy Cost in the revenue  
27 requirement upon which the Commission sets general rates:

1

Table 1: Base Energy Cost Case Studies				
		Case 1	Case 2	Case 3
Line	<b>95%/5% Sharing Mechanism</b>	Energy Cost in FAC <b>Equal To</b> Base Energy Cost in Rev. Req.	Energy Cost in FAC <b>Less Than</b> Base Energy Cost in Rev. Req.	Energy Cost in FAC <b>Greater Than</b> Base Energy Cost in Rev. Req.
a	Revenue Requirement	\$ 10,000,000	\$ 10,000,000	\$ 10,000,000
b	Base Energy Cost in Rev. Req.	\$ 4,000,000	\$ 4,000,000	\$ 4,000,000
c	Base Energy Cost in FAC	\$ 4,000,000	\$ 3,900,000	\$ 4,100,000
	<b>Outcome 1:</b> Actual Energy Cost <b>Greater Than</b> Base Energy Cost in Revenue Requirement			
d	Actual Total Energy Cost	\$ 4,200,000	\$ 4,200,000	\$ 4,200,000
	Billed to Customer:			
= b	in Permanent Rates	\$ 4,000,000	\$ 4,000,000	\$ 4,000,000
$e = (d - c) \times 0.95$	through FAC	\$ 190,000	\$ 285,000	\$ 95,000
$f = b + e$	Total Billed to Customers	\$ 4,190,000	\$ 4,285,000	\$ 4,095,000
$g = f - d$	<b>Kept/(Paid) by Company</b>	\$ (10,000)	\$ 85,000	\$ (105,000)
	<b>Outcome 2:</b> Actual Energy Cost <b>Less Than</b> Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	\$ 3,800,000	\$ 3,800,000	\$ 3,800,000
	Billed to Customer:			
= b	in Permanent Rates	\$ 4,000,000	\$ 4,000,000	\$ 4,000,000
$i = (h - c) \times 0.95$	through FAC	\$ (190,000)	\$ (95,000)	\$ (285,000)
$j = b + i$	Total Billed to Customers	\$ 3,810,000	\$ 3,905,000	\$ 3,715,000
$k = j - h$	<b>Kept/(Paid) by Company</b>	\$ 10,000	\$ 105,000	\$ (85,000)

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Case 1 illustrates that if the FAC Base Energy Cost used for the Base Factor is equal to the Base Energy Cost in the revenue requirement used for setting general rates, the utility does not over or under-collect as a result of the level of total actual energy costs. The FAC works as it is intended to.

Case 2 illustrates that if the FAC Base Energy Cost used for the Base Factor is less than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will collect more than was intended and customers pay more than the FAC was designed for them to pay, regardless of the level of actual energy costs.

Case 3 illustrates that if the FAC Base Energy Cost used for the Base Factor is greater than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will not collect all of the costs that was intended in the FAC design, and customers pay less than the entire amount intended regardless of the level of actual energy costs.

1           These three cases illustrate the importance of setting the Base Factor in the FAC  
2 correctly, *i.e.*, revising the Base Factor to match the Base Energy Cost in the revenue  
3 requirement used for setting general rates. Case 1 is the preferred case, and illustrates how the  
4 FAC is intended to work.

## 5           **F. Additional Reporting Requirements**

6           Due to the accelerated Staff review process necessary with FAC adjustment filings<sup>90</sup> Staff  
7 recommends the Commission order Empire to continue to provide the following information as  
8 part of its monthly reports as Empire agreed to do in the *Revised Stipulation and Agreement* filed  
9 April 8, 2015, in Rate Case No. ER-2014-0351, and has continued to provide in its monthly  
10 reports;

- 11           1. Monthly Southwest Power Pool (“SPP”) market settlements and revenue  
12           neutrality uplift charges;
- 13           2. Notify Staff within 30 days of entering a new long-term contract for  
14           transportation, coal, natural gas or other fuel; natural gas spot transactions  
15           are specifically excluded;
- 16           3. Provide Staff with a monthly natural gas fuel report that includes all  
17           transactions, spot and longer term; the report will include term, volumes,  
18           price and analysis of number of bids;
- 19           4. Notify Staff within 30 days of any material change in Empire’s fuel hedging  
20           policy, and provide the Staff with access to new written policy;
- 21           5. Provide Staff its Missouri Fuel Adjustment Interest calculation workpapers  
22           in electronic format with all formulas intact when Empire files for a  
23           change in the cost adjustment factor;
- 24           6. Notify Staff within 30 days of any change in Empire’s internal policies for  
25           participating in the SPP;

---

<sup>90</sup> The company must file its FAC adjustment 60 days prior to the effective date of its proposed tariff sheet. Staff has 30 days to review the filing and make a recommendation to the Commission. The Commission then has 30 days to approve or deny Staff’s recommendation.

1 7. Continue to provide Staff access to all contracts and policies upon Staff's  
2 request, at Empire's corporate office in Joplin, Missouri.

3  
4 *Staff Expert/Witness: David C. Roos*

5 **G. FAC Voltage Adjustment Factors**

6 Rule 4 CSR 240-20.090(9) requires an electric utility that desires to continue using a  
7 Commission authorized Rate Adjustment Mechanism ("RAM"), such as the current request of  
8 Empire in regard to its FAC, to complete a jurisdictional system loss study of the corresponding  
9 energy losses experienced in its delivery of electricity. This study must be based upon a  
10 consecutive twelve-month period, preferably a calendar year, and be conducted at least every  
11 four years following the Commission's initial approval of its FAC.<sup>91</sup> Empire provided a loss  
12 study in its follow-up response to Staff Data Request No. 100 in this case on January 7, 2016.  
13 This loss study contains system loss calculations/determinations based on data collected during  
14 calendar year 2014. Staff used the information in this loss study in developing the following  
15 primary and secondary voltage level adjustment factors:

Voltage Level	Voltage Adjustment Factor
Primary	1.0464
Secondary	1.0657

16  
17  
18  
19 These voltage adjustment factors account for the energy losses experienced in the delivery of  
20 electricity from the generator to the customer. These factors will be utilized in Staff's  
21 determination of a Fuel Adjustment Rate ("FAR"), applicable to the individual voltage service  
22 classification of a particular customer in the corresponding FAC tariff.

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

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<sup>91</sup> 4 CSR 240-20.090(9) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM.

1           **H. Loss Study – Compliance with FAC Rules**

2           Empire supplied Staff with a loss study in Response to Staff Data Request 100. The loss  
3 study analyzed data compiled during calendar year 2014. Therefore, Empire remains in  
4 compliance with the rule requiring a current loss study when requesting the initiation or the  
5 continuance of a FAC per 4 CSR 240-20.090(9).

6  
7 *Staff Expert/Witness: Alan J. Bax*

8           **I. Heat Rate Testing Review**

9           If an electric utility requests that a Rate Adjustment Mechanism (Fuel Adjustment Clause  
10 (“FAC”)) be continued or modified, Commission Rule 4 CSR 240-3.161(3)(Q) requires that an  
11 electric utility shall file specific information as a part of its direct testimony in a general rate  
12 proceeding:

13                   (Q) The results of heat rate tests and/or efficiency tests on all the  
14 electric utility’s nuclear and non-nuclear steam generators, HRSG,  
15 steam turbines and combustion turbines conducted within the  
16 previous twenty-four (24) months;

17           The Commission authorized Empire’s FAC in Case No. ER-2008-0093. The FAC was  
18 continued in Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2014-0351.  
19 Empire has requested the FAC be continued in the current general rate proceeding, Case No.  
20 ER-2016-0023.

21           Empire witness Todd W. Tarter filed the results of the most recent heat rate/efficiency  
22 tests for Empire’s generating units in schedule TWT-7 of his direct testimony. Staff has  
23 conducted a review of those results and found them to be reasonable based on comparisons with  
24 data filed in previous general rate case proceedings and known changes in power plant operating  
25 parameters. All of the testing dates submitted by Empire were found to be in accordance with  
26 the twenty-four (24) month requirement of 4 CSR 240-3.161(3)(Q).

27  
28 *Staff Expert/Witness: Charles T. Poston*



1 **XII. Miscellaneous**

2 **A. Proposed Acquisition**

3 On December 13, 2015, Empire issued a press release, in response to media reports  
4 concerning stock trading activity, confirming that the Company “is in the early stages of  
5 exploring strategic alternatives, and has retained a financial advisor with regard to the  
6 exploration of such strategic alternatives. No decision regarding the strategic alternatives has  
7 been made by the Board of Directors.” No other information was provided at that time. On  
8 February 9, 2016, Empire announced that Algonquin Power & Utilities Corp. (“Algonquin”) will  
9 acquire The Empire District Electric Company and included details related to this activity.  
10 Algonquin is a company based in Oakville, Ontario, which has a U.S. subsidiary, Liberty  
11 Utilities, which is currently regulated by the PSC. A subsidiary of Liberty Utilities, Liberty  
12 Utilities (Central) Co., was created to acquire the capital stock of Empire for this proposed  
13 transaction and is an indirect subsidiary of Algonquin. On February 25, 2016, Empire filed a  
14 notice with the PSC concerning this proposed transaction.

15 In response to the announcement of this proposed transaction, Staff issued Data Request  
16 No. 0201 in this case requesting the hours spent by Empire employees related to this proposed  
17 transaction. Empire’s response was that any time spent on this proposed acquisition by Empire  
18 employees has not been separately tracked. Staff is concerned that these hours were not tracked  
19 and asserts it is unreasonable that Empire did not measure its cost related to its holding  
20 company function. Empire’s failure to measure these costs resulted in acquisition payroll and  
21 related expense being recorded as utility expense. Staff will conduct a review to determine the  
22 level of this activity that occurred before September 30, 2015. This is a matter that will  
23 definitely impact the update period through March 31, 2016. It is unclear at this time whether  
24 any of these costs are reflected in Staff’s direct filing test period. This event was and continues  
25 to be a significant activity for Empire. Empire should correct this situation quickly. Until such  
26 time, Staff has included an estimate in its current recommendation to reflect the cost associated  
27 with this proposed transaction and will update throughout this case as more information  
28 becomes available.

29 *Staff Expert/Witness: Amanda C. McMellen*  
30

## B. Renewable Energy Standard (“RES”) Summary

The Missouri Renewable Energy Standard (“RES”)<sup>92</sup> was enacted as a voter initiative petition in November 2008. Provisions of the resulting statute and regulations require Empire (and the other investor-owned utilities) to meet certain requirements regarding the use of renewable energy while not exceeding the one percent (1%) retail rate impact limit. The RES requires Empire to provide a rebate to its retail customers for installation of solar electric systems on their premises. Empire was previously believed to be exempt from offering solar rebates to its customers and exempt from the solar RES requirements. The exemption was challenged and on February 10, 2015, the Missouri Supreme Court issued an opinion that Empire was not exempt from these requirements. This resulted in Empire filing proposed solar rebate tariff sheets to offer solar rebates to its customers on May 5, 2015, that became effective May 16, 2015.<sup>93</sup> Because the opinion was not issued until 2015, Empire did not retire solar Renewable Energy Credits (“RECs”) for compliance year 2014. Commission rule 4 CSR 240-20.100(3)(J), allows a utility to retire RECs in January, February, and March following the calendar year for which compliance is being achieved, and receive credit in the compliance year. Theoretically, Empire could have retired solar RECs in 2015 for 2014 compliance, but this was probably not practical with the timing of the opinion.

For calendar years 2014 through 2017, the RES requires Empire to generate or purchase five percent (5%) of its retail sales using renewable energy resources.<sup>94</sup> Empire must derive two percent (2%) of the renewable energy requirement from solar energy.<sup>95</sup> RECs can be banked for three (3) years and utilized for future compliance purposes.<sup>96</sup> Empire files annually a RES Compliance Plan and RES Compliance Report.<sup>97</sup> Each RES Compliance Plan provides information regarding the utility’s plan for the current calendar year and the subsequent two (2) calendar years. The RES Compliance Report is a status report on the utility’s compliance for the

---

<sup>92</sup> Mo. Rev. Stat. § 393.1020 (2000).

<sup>93</sup> See Case No. ET-2015-0285.

<sup>94</sup> Mo. Rev. Stat. § 393.1030 .1(1) (2000).

<sup>95</sup> Mo. Rev. Stat. § 393.1030.1 (2000).

<sup>96</sup> “An unused credit may exist for up to three years from the date of its creation.” Mo. Rev. Stat. § 393.1030.2 (2000).

<sup>97</sup> Empire filed its RES Plan for 2014-2016 and its RES Report for calendar year 2014 in EO-2015-0260; Its 2015 RES Plan and RES Report is due on April 15.

1 preceding calendar year. For the 2014 calendar year, Empire utilized renewable energy and  
2 RECs from Ozark Beach Hydroelectric Project for the non-solar requirement.<sup>98</sup>

3  
4 *Staff Expert/Witness: Claire M. Eubanks, PE*

5 **Appendices:**

6 Appendix 1: Staff Credentials

7 Appendix 2: Support for Staff Cost of Capital Recommendation

8 Appendix 3: Alphabetical Listing of Testimony Schedules

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<sup>98</sup> EO-2015-0260, *2014 Annual Renewable Energy Standard Compliance Report*, pg 4-5.

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**


In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF ALAN J. BAX**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

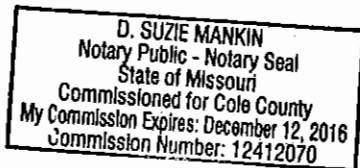
**COMES NOW ALAN J. BAX** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

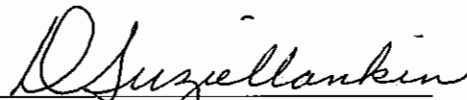
Further the Affiant sayeth not.

  
\_\_\_\_\_  
**ALAN J. BAX**

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF MICHELLE A. BOCKLAGE**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

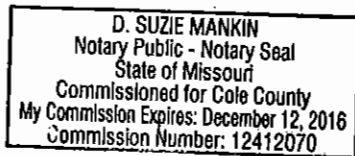
**COMES NOW MICHELLE A. BOCKLAGE** and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

*Michelle A. Bocklage*  
MICHELLE A. BOCKLAGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



*D. Suzie Mankin*  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

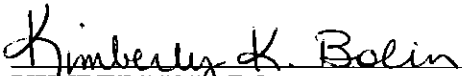
In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF KIMBERLY K. BOLIN**

STATE OF MISSOURI )  
) ss.  
COUNTY OF COLE )

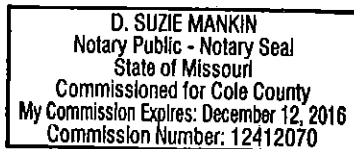
COMES NOW KIMBERLY K. BOLIN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

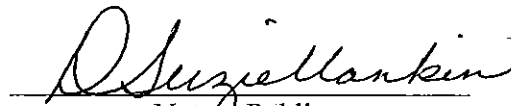
Further the Affiant sayeth not.

  
KIMBERLY K. BOLIN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF KORY BOUSTEAD**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

**COMES NOW KORY BOUSTEAD** and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

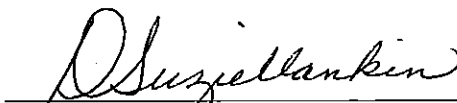
Further the Affiant sayeth not.

  
\_\_\_\_\_  
KORY BOUSTEAD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.

D. SUZIE MANKIN  
Notary Public - Notary Seal  
State of Missouri  
Commissioned for Cole County  
My Commission Expires: December 12, 2016  
Commission Number: 12412070

  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

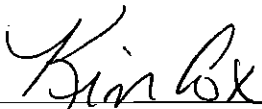
In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF KIM COX**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

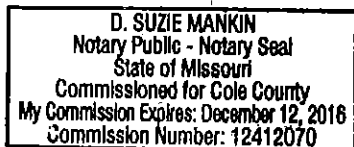
COMES NOW KIM COX and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

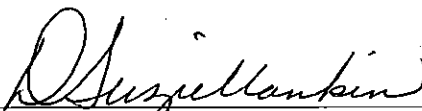
Further the Affiant sayeth not.

  
\_\_\_\_\_  
KIM COX

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public



**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF CLAIRE M. EUBANKS, PE**

STATE OF MISSOURI )  
) ss.  
COUNTY OF COLE )

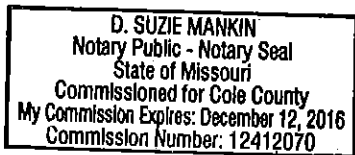
COMES NOW CLAIRE M. EUBANKS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

*Claire M Eubanks*  
CLAIRE M. EUBANKS, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



*D. Suzie Mankin*  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric    )  
Company's Request for Authority to                )  
Implement a General Rate Increase for            )  
Electric Service                                        )

Case No. ER-2016-0023

**AFFIDAVIT OF BRAD J. FORTSON**

STATE OF MISSOURI        )  
                                      )  
COUNTY OF COLE         )        ss.

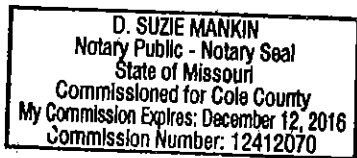
COMES NOW BRAD J. FORTSON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.


Further the Affiant sayeth not.

  
BRAD J. FORTSON

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF KEITH D. FOSTER**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

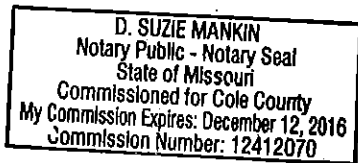
**COMES NOW KEITH D. FOSTER** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

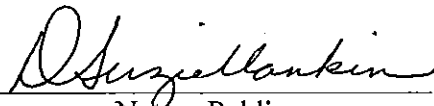
Further the Affiant sayeth not.

  
\_\_\_\_\_  
**KEITH D. FOSTER**

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF JERMAINE GREEN**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

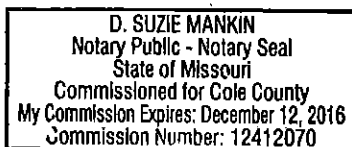
**COMES NOW JERMAINE GREEN** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

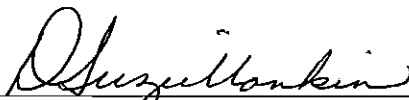
Further the Affiant sayeth not.

  
\_\_\_\_\_  
JERMAINE GREEN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF SHANA GRIFFIN**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

**COMES NOW SHANA GRIFFIN** and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

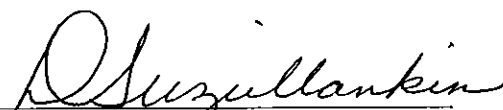
Further the Affiant sayeth not.

  
\_\_\_\_\_  
**SHANA GRIFFIN**

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.

D. SUZIE MANKIN  
Notary Public - Notary Seal  
State of Missouri  
Commissioned for Cole County  
My Commission Expires: December 12, 2016  
Commission Number: 12412070

  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**


In the Matter of The Empire District Electric )  
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Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF JENNIFER K. GRISHAM**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

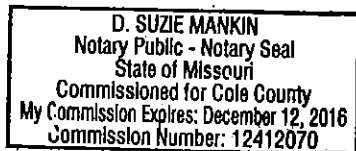
COMES NOW JENNIFER K. GRISHAM and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

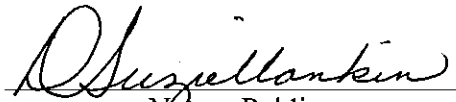
Further the Affiant sayeth not.

  
JENNIFER K. GRISHAM

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

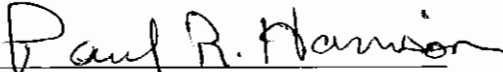
In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF PAUL R. HARRISON**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

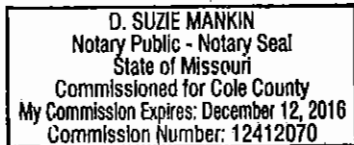
COMES NOW PAUL R. HARRISON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

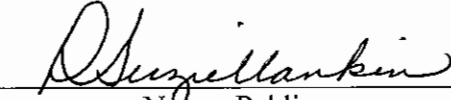
Further the Affiant sayeth not.

  
\_\_\_\_\_  
PAUL R. HARRISON

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF ROBIN KLIETHERMES**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

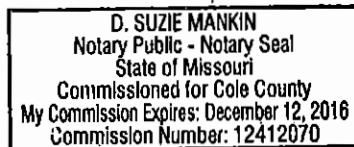
**COMES NOW ROBIN KLIETHERMES** and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

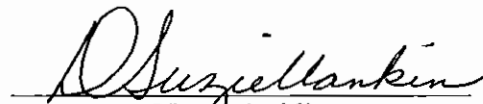
Further the Affiant sayeth not.

  
\_\_\_\_\_  
ROBIN KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public



**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF SARAH L. KLIETHERMES**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

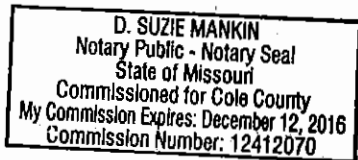
COMES NOW SARAH L. KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

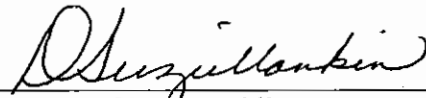
Further the Affiant sayeth not.

  
\_\_\_\_\_  
SARAH L. KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF SHAWN E. LANGE**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

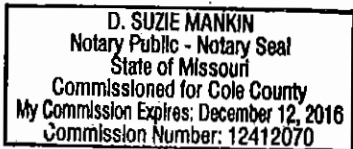
COMES NOW SHAWN E. LANGE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

*Shawn E. Lange*  
SHAWN E. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



*D. Suzie Mankin*  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric    )  
Company's Request for Authority to            )  
Implement a General Rate Increase for        )  
Electric Service                                    )

Case No. ER-2016-0023

**AFFIDAVIT OF ERIN L. MALONEY**

STATE OF MISSOURI    )  
                                  )  
COUNTY OF COLE     )        ss.

**COMES NOW ERIN L. MALONEY** and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

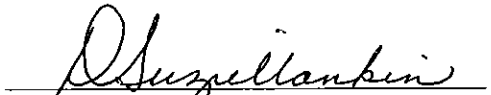
Further the Affiant sayeth not.

  
\_\_\_\_\_  
**ERIN L. MALONEY**

**JURAT**

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.

D. SUZIE MANKIN  
Notary Public - Notary Seal  
State of Missouri  
Commissioned for Cole County  
My Commission Expires: December 12, 2016  
Commission Number: 12412070

  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF AMANDA C. McMELLEN**

STATE OF MISSOURI )  
) ss.  
COUNTY OF COLE )

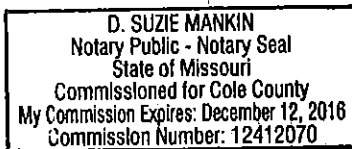
COMES NOW AMANDA C. McMELLEN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

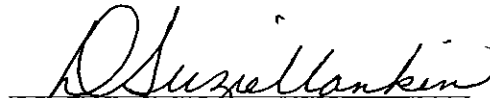
Further the Affiant sayeth not.

  
AMANDA C. McMELLEN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF CHARLES T. POSTON, PE**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

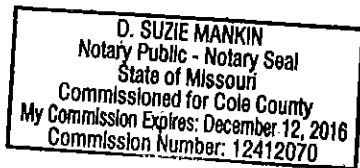
**COMES NOW CHARLES T. POSTON** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

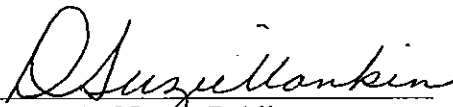
Further the Affiant sayeth not.

  
\_\_\_\_\_  
**CHARLES T. POSTON, PE**

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

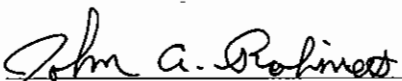
In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF JOHN A. ROBINETT**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

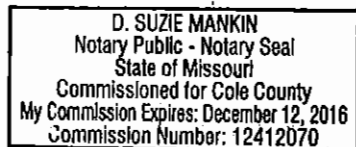
**COMES NOW JOHN A. ROBINETT** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

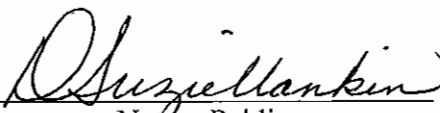
Further the Affiant sayeth not.

  
\_\_\_\_\_  
JOHN A. ROBINETT

**JURAT**

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF DAVID C. ROOS**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

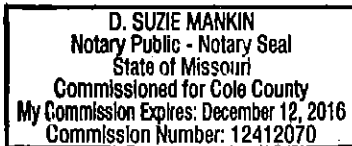
**COMES NOW DAVID C. ROOS** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

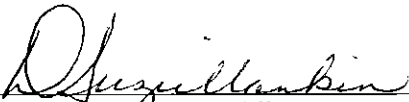
Further the Affiant sayeth not.

  
\_\_\_\_\_  
DAVID C. ROOS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF ASHLEY R. SARVER**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

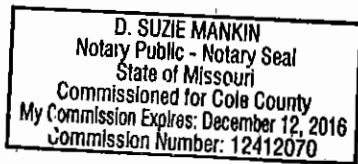
COMES NOW ASHLEY R. SARVER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

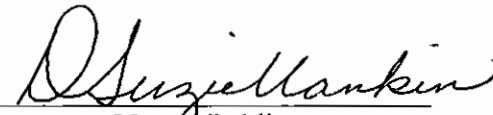
Further the Affiant sayeth not.

  
\_\_\_\_\_  
ASHLEY R. SARVER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
\_\_\_\_\_  
Notary Public



**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF MICHAEL L. STAHLMAN**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

**COMES NOW MICHAEL L. STAHLMAN** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

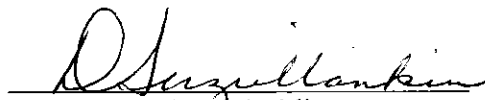
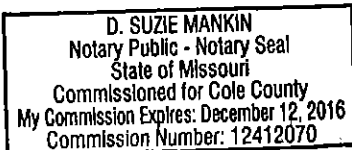
Further the Affiant sayeth not.



**MICHAEL L. STAHLMAN**

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

In the Matter of The Empire District Electric )  
Company's Request for Authority to ) Case No. ER-2016-0023  
Implement a General Rate Increase for )  
Electric Service )

**AFFIDAVIT OF SEOUNG JOUN WON, PhD**

STATE OF MISSOURI )  
 ) ss.  
COUNTY OF COLE )

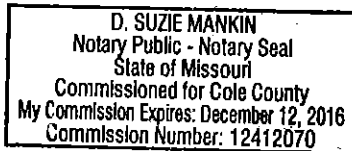
**COMES NOW SEOUNG JOUN WON, PhD** and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

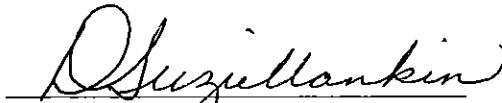
Further the Affiant sayeth not.

  
**SEOUNG JOUN WON, PhD**

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24<sup>th</sup> day of March 2016.



  
Notary Public