| | |
|---|---|
| **Exhibit No.:** | ________________ |
| **Issue(s):** | Rate Case Expense/ Management Expense Charges |
| **Witness/Type of Exhibit**: | Conner/Direct |
| **Sponsoring Party**: | Public Counsel |
| **Case No**.: | WR-2020-0344 |

# DIRECT TESTIMONY

# OF

# AMANDA C. CONNER

Submitted on Behalf of the Office of the Public Counsel

# MISSOURI-AMERICAN WATER COMPANY

CASE NO. WR-2020-0344

November 24, 2020

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| In the Matter of Missouri-American | ) | |
| Water Company's Request for | ) | |
| Authority to Implement General Rate | ) | Case No. WR-2020-0344 |
| Increase for Water and Sewer Service | ) | |
| Provided in Missouri Service Areas | ) | |

**VERIFICATION OF AMANDA CONNER**

Amanda Conner, under penalty of perjury, states:

1. Attached hereto and made a part hereof for all purposes is my direct testimony in the above-captioned case.

2. My answer to each question in the attached direct testimony is true and correct to the best of my knowledge, information, and belief.

*/s/ Amanda C. Conner*
Amanda C. Conner
Utility Regulatory Auditor
Office of the Public Counsel

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**DIRECT TESTIMONY**

**OF**

**AMANDA C CONNER**
**MISSOURI AMERICAN WATER COMPANY**

**CASE NO. WR-2020-0344**

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. Amanda C. Conner, P.O. Box 2230, Jefferson City, Missouri 65102.

**Q. By whom are you employed and in what capacity?**

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Utility Regulatory Auditor.

**Q. On whose behalf are you testifying?**

A. I am testifying on behalf of the OPC.

**Q. What is the nature of your duties at the OPC?**

A. My duties include performing audits, reviews, and examinations of the books and records of public utilities operating within the State of Missouri.

**Q. Have you conducted a review of the books and records of Missouri American Water Company ("MAWC") in this rate case?**

A. Yes.

**Q. Please describe your educational background.**

A. I earned a Bachelor of Science degree in Accounting from Columbia College in May 2012.

**Q. Please describe your related background.**

A. I began my employment with the OPC in February of 2016. Prior to my current position, I worked for the Missouri Department of Revenue as a Tax Processing Technician III for 8 years addressing various types of tax issues for the public.

**Q. Have you received specialized training related to public utility accounting and ratemaking?**

A. Yes. I received regulatory and ratemaking training as an employee of the OPC. In addition, I attended the Utility Ratemaking Fundamentals course sponsored by Brubaker Associate, Inc. (BAI) in the spring of 2016. In the fall of 2016, I attended the National Association of Regulatory Utility Commissioners (NARUC) Utility Rate School sponsored by Michigan State University.

**Q. Have you previously filed testimony before the Missouri Public Service Commission ("Commission" or "PSC")?**

A. Yes. Please refer to Schedule ACC-D-1, attached to this testimony, for a list of cases where I submitted testimony.

**Q. What is the purpose of your direct testimony?**

A. I present my ratemaking testimony on the following topics: 1) Rate Case Expense and 2) Management Expense Charges.

**<u>RATE CASE EXPENSE</u>**

**Q. What types of costs are included in MAWC's proposed rate case expense?**

A. As reflected in MAWC's workpaper CAS-13, MAWC is seeking rate recovery for estimated rate case expense of $1,705,935 to be collected over three years in the amount of $568,645 per year. The Depreciation Study expense of $73,500 to be collected over five years in the amount of $14,700 per year. Rate case expense consists primarily of legal and consulting fees.

**Q. Is rate case expense significantly different from other types of operating expenses?**

A. Yes. For example, MAWC has only an estimated amount for its rate case expense that will vary based on how the rate case proceeds. Other operating expenses, while subject to updates, will not change directly because of the processing of the case. Additionally, a portion of rate case expense is incurred solely for the benefit of the shareholders.

**Q. What is your opinion on the appropriate allocation of rate case expense between ratepayers and shareholders in a utility rate case?**

A. I support a sharing of rate case expense because rate cases benefit both customers and shareholders. While it must be specific to each rate case, the adjustment methodology of allocating rate case expense based on the ratio of the dollar revenue requirement ordered by the Commission to the dollar revenue requirement sought by a utility in its rate case application is reasonable.

The Commission in its Report and Order in KCPL's ER-2014-0370 rate case ("2014 Order") ordered this adjustment approach. Since that Commission Order, the Commission Staff ("Staff") has applied this rate case adjustment methodology in most, if not all, of its rate case Cost of Service Reports. The approach used by the Commission in its 2014 Order is the approach that in my opinion allocates the cost appropriately.

**Q. Why do you believe that the Commission ordered a sharing of rate case expense in its 2014 Order?**

A. The Commission Order notes that although some amount of rate case expense is properly supported by customer rates, customers paying for the entirety of rate case expense gives utilities an undue advantage in rate case proceedings, and reduces the company's incentive to limit rate case expenses. The Commission, rather than ordering a strict 50/50 sharing, decided that rate case expense should be divided based on a percentage of rate case expense relative to the ordered rate change. Below I am including some highlights from the 2014 Order and have included the order as schedule ACC-D-2:

Para 164.

> *Awarding a utility all of its incurred rate case expenses could provide that utility with a significant financial advantage over other participants in the rate case process, who may be constrained by budgetary and other financial restrictions. Such a practice does not encourage reasonable levels of cost containment in the utility's rate case expense decisions.*

Para 165.

> *An incentive for a utility to limit its rate case expense is to tie a utility's percentage recovery of rate case expense to the percentage of its rate increase request that the Commission finds just and reasonable. Use of this approach would directly tie a utility's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in a rate case*

Page 70.

> *However, rate case expense is also different from most other types of utility operational expenses, in that 1) the rate case process is adversarial in nature, with the utility on one side and its customers on the other; 2) rate case expense produces some direct benefits to shareholders that are not shared with customers, such as seeking a higher return on equity; 3) requiring all rate case expense to be paid by ratepayers provides the utility with an inequitable financial advantage over other case participants; and 4) full reimbursement of all rate case expense does nothing to encourage reasonable levels of cost containment.*

Page 72:

> *The Commission finds that in order to set just and reasonable rates under the facts in this case, the Commission will require KCPL shareholders to cover a portion of KCPL's rate case expense. One method to encourage KCPL to limit its rate case expenditures*

> *would be to link KCPL's percentage recovery of rate case expense to the percentage of its rate increase request the Commission finds just and reasonable. The Commission determines that this approach would directly link KCPL's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in this rate case.*

To summarize this order, Staff and OPC have limited financial resources to use in the rate case process so the utility company has a financial advantage. The Commission found this methodology would incentivize a company to limit its rate case expense because it is directly tied to the allowable recovery of revenue requirement. , This methodology encourages utility companies to be more conservative in their requested rate increase amount. This methodology is not about the disallowance of expenses, the focus of this methodology is to ensure ratepayers get an even and fair playing field in the rate case process.

**Q. What has the Commission decided in the last rate case regarding rate case expense (ER-2019-0374)**

A. The Commission ordered a sharing mechanism that employed a 50/50 split sharing of rate case expense for the Empire District Electric Company earlier this year. The Commission found that both ratepayers and shareholders benefit so in order to set just and reasonable rates, shareholders and ratepayers would share equally in the rate case expense. Though my opinion is that the ratio method followed by the 2014 Order is reasonable, requiring ratepayers to only pay half of the rate case expense is also an acceptable alternative. I have attached this Report and Order at schedule ACC-D-3

**Q. Did you adjust MAWC's rate case expense estimation for this rate case?**

A. Yes. My adjustment is attached as Schedule ACC-D-4. I excluded the $1,060 unamortized balance from the WR-2015-0301 rate case expense, because in the Stipulation and Agreement filed on March 16, 2016, the rate case expense was to be amortized over 30 months. It is now well over 30 months. I cannot currently calculate the actual rate case expense for the estimated amount because the Revenue Requirement has not been decided.

However, using the data filed by MAWC with the rate case expense as of July 31, 2020, the total rate case expense spent by the Company is $452,363. By using the same methodology, I calculated the total rate case expense of $226,182 and the normalized amount to be collected over three years of $75,394. This amount does not include the Depreciation Study, with a 5-year amortized amount of $14,700. As more data comes in, I will adjust this rate case expense recommendation to allow for additional rate case expenses.

## MANAGEMENT EXPENSE CHARGES

**Q. Does MAWC have a policy on the types of employee expenses that are reimbursable by the utility?**

A. Yes. MAWC provided an overview of MAWC's Employee Travel and Business Expenditures Policy, Policy Number POL-BUSSERV02 (Expense Policy) in response to OPC DR 1203. This Expense Policy is attached as ACC-D-5

**Q. Do you have any concerns regarding the Expense Policy?**

A. Yes. Under Meals, the Expense Policy states that in certain circumstances, alcoholic beverages, in moderation, may be included with meals.

**Q. Did you express this concern in MAWC's WR-2017-0285 Rate Case?**

A. Yes.

**Q. Do you have any recommendations regarding MAWC's cost reimbursement for employee consumption of alcohol?**

A. Yes. OPC has taken the position in previous rate cases that ratepayers should not be required to reimburse utility employees for their alcohol purchases. I am taking the same position in this rate case, as ratepayers should not be required to pay for the consumption of alcohol.

**Q. Are you conducting a review of MAWC management expense charges?**

A. Yes. I am conducting a comprehensive and detailed analysis of all or substantially all of MAWC officer expenses charged in the December 31, 2019 test year general ledger.

**Q. What were your findings from this review?**

A. While my analysis is not complete, I am proposing an adjustment based on my work to date. My current adjustment removes approximately $184,198 of MAWC direct and AWW allocated excessive, unreasonable, and imprudent charges to rate base.

**Q. At this time are there any expenses you have found to be imprudent or excessive charges to the regulatory expense accounts?**

A. Yes. A few of these items listed below are:

1. Trips to Europe.
2. Trip to Singapore.
3. Trip to Japan.
4. Trip to Australia.
5. Trip to Canada.

6. Board Retreat.
7. Charges associated with other lobbying activities such as EEI and NAWC.
8. Charges allocated to Missouri that are for the benefit of other state ratepayers. Such as rate cases in Tennessee, Kentucky, Virginia, etc.
9. Gifts and parties associated with retirements, bereavement, and holiday/birthday celebrations.
10. Charges for award ceremonies.

**Q. Is there any data that you need to finish your adjustment?**

A. Yes. I have a data request to MAWC requesting the total amount of expenses charged by managers to MAWC. Once I receive this data, I will have a complete adjustment.

**Q. Are there any other issues from the WR-2017-0285 rate cases that you addressed, that remain unresolved?**

A. Yes, I brought up then the fact that other states rate cases and trips were allocated to Missouri in the last rate case. It appears that MAWC is still seeking to charge Missouri ratepayers for out-of-state trips and matters wholly unrelated to providing local water and sewer service. Missouri ratepayers should only be charged for expenses that benefit them, but these trips to other states largely benefit MAWC and other customers outside of Missouri. I also took issue with gifts and receptions for MAWC employees being included in rates because they are not necessary for safe and adequate service, and therefore should not be charged to ratepayers.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

# CASE PARTICIPATION
# OF
# AMANDA C. CONNER

| Company Name | Case No. |
|---|---|
| Empire District Electric Company | ER-2016-0023 |
| Kansas City Power & Light Company | ER-2016-0285 |
| Laclede Gas Company | GR-2017-0215 |
| Missouri Gas Energy | GR-2017-0216 |
| Missouri American Water Company | WR-2017-0285 |
| Liberty Utilities | GR-2018-0013 |
| KCP&L Greater Missouri Operations Company | ER-2018-0146 |
| Kansas City Power & Light Company | ER-2018-0145 |
| Empire District Electric Company | ER-2019-0374 |

# BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of Kansas City Power & Light | ) | **File No. ER-2014-0370 *et al.*** |
| Company's Request for Authority to Implement a | ) | YE-2015-0194 |
| General Rate Increase for Electric Service | ) | YE-2015-0195 |

# REPORT AND ORDER

**Issue Date:** September 2, 2015

**Effective Date:** September 15, 2015

ACC-D-2

# BEFORE THE PUBLIC SERVICE COMMISSION
# OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of Kansas City Power & Light<br>Company's Request for Authority to Implement a<br>General Rate Increase for Electric Service | )<br>)<br>) | **File No. ER-2014-0370 *et al.***<br>YE-2015-0194<br>YE-2015-0195 |

## REPORT AND ORDER

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# APPEARANCES

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**SIERRA CLUB:**

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**BRIGHTERGY, LLC:**

**Andrew J. Zellers,** General Counsel, 1712 Main St., Kansas City, Missouri 64108.

**UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI:**

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**CITY OF KANSAS CITY, MISSOURI:**

**Mark W. Comley,** 601 Monroe St., Suite 301, Jefferson City, Missouri 65102.

**SENIOR REGULATORY LAW JUDGE:** Michael Bushmann

# REPORT AND ORDER

## I. Procedural History

### A. Tariff Filings, Notice, and Intervention

On October 30, 2014, Kansas City Power & Light Company ("KCPL") filed tariff sheets designed to implement a general rate increase for utility service. The tariff sheets bore an effective date of November 29, 2014. In order to allow sufficient time to study the effect of the tariff sheets and to determine if the rates established by those sheets are just, reasonable, and in the public interest, the tariff sheets were suspended until September 29, 2015. The Commission directed notice of the filings and set an intervention deadline. The Commission granted intervention requests from the following entities: the Missouri Department of Economic Development- Division of Energy, Midwest Energy Consumers Group, Missouri Industrial Energy Consumers, Brightergy, LLC, Sierra Club, Consumers Council of Missouri, U.S. Department of Energy and Federal Executive Agencies, Union Electric Company d/b/a Ameren Missouri, Missouri Gas Energy, the City of Kansas City, Missouri, and the International Brotherhood of Electrical Workers Local Unions No. 412, 1464, and 1613. On January 30, 2015, the Commission consolidated this case with a related matter in File No. EU-2015-0094.

### B. Test Year and True-Up

The test year is a central component in the ratemaking process. Rates are usually established based upon a historical test year which focuses on four factors: (1) the rate of return the utility has an opportunity to earn; (2) the rate base upon which a return may be earned; (3) the depreciation costs of plant and equipment; and (4) allowable operating expenses.[1] From these four factors is calculated the "revenue requirement," which, in the context of rate setting, is the amount of revenue ratepayers must generate to pay the costs of producing the utility service they receive while yielding a reasonable rate of return to the investors.[2] A historical test year is used because the past expenses of a utility can be used as a basis for determining what rate is reasonable to be charged in the future.[3]

The parties agreed to, and the Commission adopted, a test year of twelve months ending on March 31, 2014, updated through December 31, 2014. The Commission also established the true-up period to run through May 31, 2015, to reflect any significant and material impacts on KCPL's revenue requirement. The use of a true-up audit and hearing in ratemaking is a compromise between the use of a historical test year and the use of a projected or future test year.[4] It involves adjustment of the historical test year figures for known and measurable subsequent or future changes.[5] However, the true-up is generally limited to only those accounts necessarily affected by some significant known and measurable change, such as a new labor contract, a new tax rate, or the completion of a new capital asset. The true-up is a device employed to reduce regulatory lag, which is "the lapse of time between a change in revenue requirement and the reflection of that change in rates."[6]

### C. Local Public Hearings

On December 3, 2014, some of the parties filed a *Joint Proposed Procedural Schedule*, which included a recommendation for the dates and locations for local public

[1] *State ex rel. Union Electric Company v. Public Service Comm'n*, 765 S.W.2d 618, 622 (Mo. App. 1988).
[2] *State ex rel. Capital City Water Co. v. Public Service Comm'n*, 850 S.W.2d 903, 916 n. 1 (Mo. App. 1993).
[3] *See State ex rel. Utility Consumers' Council of Missouri, Inc. v. Public Service Comm'n*, 585 S.W.2d 41, 59 (Mo. banc 1979).
[4] *St. ex rel. Missouri Public Service Comm'n v. Fraas,* 627 S.W.2d 882, 887-888 (Mo. App. 1981).
[5] *Id.* at 888.
[6] *In the Matter of St. Louis County Water Company*, Case No. WR-96-263 (*Report & Order*, issued December 31, 1996), at p. 8; 5 Mo. P.S.C. 3d 341, 346.

hearings to give KCPL's customers an opportunity to respond to the requested rate increase. The Commission conducted local public hearings in Kansas City, Belton, Marshall, and Gladstone.[7]

**D. Stipulations and Agreements**

On June 26, 2015, some of the parties filed a *Non-Unanimous Stipulation and Agreement Regarding Pension and Other Post-Employment Benefits*. On July 1, 2015, some of the parties filed a *Partial Non-Unanimous Stipulation and Agreement as to Certain Issues* and a *Partial Non-unanimous Stipulation and Agreement as to True Up, Depreciation and Other Miscellaneous Issues.* Although these stipulations and agreements were not signed by all parties, they became unanimous stipulations and agreements because no party filed a timely objection.[8] These stipulations and agreements resolved a number of the issues in dispute between the parties. The Commission found the stipulations and agreements to be reasonable and approved them on July 17, 2015. The issues resolved in these three partial stipulations and agreements will not be addressed further in this report and order, except as they may relate to any unresolved issues.

On June 16, 2015, some of the parties filed a *Non-Unanimous Stipulation and Agreement on Certain Issues* ("Rate Design Agreement"), which addressed issues relating to class cost of service, rate design, and tariffs. On August 3, 2015, Staff and KCPL filed a *Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, and Rate Switcher Revenue Adjustments* ("True-Up Agreement"), which attempted to 1) resolve all issues relating to weather normalization, rate revenues, and the resulting class billing determinants used in developing rates for all rate classes, and 2) assign a revenue shortfall of $500,000 for rate switchers in the LGS and LP rate

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[7] Transcript, Vols 3, 4, 6-8.
[8] Commission Rule 4 CSR 240-2.115(2).

classes in order to account for any of those customers migrating to a different rate schedule to receive more advantageous pricing as a result of the Rate Design Agreement. KCPL objected to the Rate Design Agreement and the Office of Public Counsel objected to the True-Up Agreement, so those two stipulations and agreements became joint position statements of the signatory parties, and all the issues addressed in the Rate Design Agreement and True-Up Agreement remain for determination after hearing.[9]

**E. Evidentiary Hearing**

The evidentiary hearing was held on June 15-19, 29 and 30, 2015, and July 1, 2015.[10] A true-up hearing was held on July 20, 2015.[11] During the hearings, the parties presented evidence relating to the unresolved issues previously identified by the parties.

**F. Case Submission**

During the evidentiary hearing and true-up hearing held at the Commission's offices in Jefferson City, Missouri, the Commission admitted the testimony of 61 witnesses, received 179 exhibits into evidence, and took official notice of certain matters.[12] Post-hearing briefs were filed according to the post-hearing procedural schedule. The final post-hearing briefs were filed on August 3, 2015, and the case was deemed submitted for the Commission's decision on that date.[13]

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[9] Commission Rule 4 CSR 240-2.115(2)(D).

[10] Transcript, Vols 9-20.

[11] Transcript, Vols 21 and 22.

[12] At the hearing, the regulatory law judge took official notice of the following: 1) Commission's Report & Order in File No. TO-97-397, 2) Commission's Report & Order in File No. ER-2014-0258, 3) Commission's Report & Order in File No. ER-2014-0351,4) Commission's Report & Order in File No. ER-2010-0356, and 5) the legislative history of Senate Bill 179 contained in Exhibit 152.

[13] "The record of a case shall stand submitted for consideration by the commission after the recording of all evidence or, if applicable, after the filing of briefs or the presentation of oral argument." Commission Rule 4 CSR 240-2.150(1).

# II. General Matters

## A. General Findings of Fact

1. Kansas City Power & Light Company ("KCPL"), founded in 1882, is a wholly-owned subsidiary of Great Plains Energy Incorporated, both of which are headquartered in Kansas City, Missouri.[14] KCPL is a vertically-integrated, regulated electric utility that provides generation, transmission, and distribution service as part of its sale of electricity to retail and wholesale customers in Missouri and Kansas.[15]

2. The Office of the Public Counsel ("Public Counsel") is a party to this case pursuant to Section 386.710(2), RSMo[16], and by Commission Rule 4 CSR 240-2.010(10).

3. The Staff of the Missouri Public Service Commission ("Staff") is a party to this case pursuant to Section 386.071, RSMo, and Commission Rule 4 CSR 240-2.010(10).

4. KCPL provides electric service to approximately 519,000 customers, including approximately 457,700 residences, 59,300 commercial firms, and 2,100 industrials, municipalities, and other electric utilities, in the Kansas City metropolitan area and surrounding cities.[17]

5. KCPL's base load generating capacity consists of ownership in four large coal-fired generating stations, the Wolf Creek nuclear power generating station, 2,200 megawatts (MW) of natural gas and oil-fired peaking capacity, and 149 MW of wind generating capacity. In 2011 and 2013, KCPL negotiated long-term power purchase agreements for additional wind and hydro generation. KCPL operates and maintains

[14] Ex. 114, Heidtbrink Direct, p. 3.
[15] Ex. 210, Featherstone Direct, p. 11.
[16] Unless otherwise stated, all statutory citations are to the Revised Statutes of Missouri, as codified in the year 2000 and subsequently revised or supplemented.
[17] Ex. 114, Heidtbrink Direct, p. 3.

approximately 12,000 miles of distribution lines and 1,800 miles of transmission lines to serve its customers.[18]

6. The proposed tariffs filed by KCPL in this case were designed to generate an aggregate revenue increase of approximately $120.9 million, or 15.75%, based on a current Missouri jurisdictional base retail revenue of $767.4 million.[19]

7. In order to determine the appropriate level of utility rates, the Commission must calculate a revenue requirement for KCPL, which is the increase or decrease in revenue KCPL needs in order to provide safe and reliable service, as measured using KCPL's existing rates and cost of service.[20]

8. The revenue requirement calculation can be identified by a formula as follows:[21] Revenue Requirement = Cost of Providing Utility Service or RR= O + (V - D) R where,

| | | |
|---|---|---|
| RR | = | Revenue Requirement; |
| O | = | Operating Costs; (such as fuel, payroll, maintenance, etc., Depreciation and Taxes); |
| V | = | Gross Valuation of Property Used for Providing Service; |
| D | = | Accumulated Depreciation Representing the Capital Recovery of Gross Property Investment. |
| (V – D) | = | Rate Base (Gross Property Investment less Accumulated Depreciation = Net Property Investment) |
| R | = | Overall Rate of Return or Weighted Cost of Capital |
| (V - D) R | = | Return Allowed on Net Property Investment |

9. A test year is a historical year used as the starting point for determining the basis for adjustments that are necessary to reflect annual revenues and operating costs in calculating any shortfall or excess of earnings by the utility. Adjustments, such as annualization and normalization adjustments, are made to the test year results when the

[18] *Id.* at p. 3-4.
[19] *Id.* at p. 12.
[20] Ex. 210, Featherstone Direct, p. 26.
[21] *Id*. at p. 26-27.

unadjusted results do not fairly represent the utility's most current annual level of existing revenue and operating costs.[22]

10. The test year for this case is the twelve months ending March 31, 2014, updated to December 31, 2014.[23]

11. The Commission also selected a true-up period ending May 31, 2015, in order to account for any significant changes in KCPL's cost of service that occurred after the end of the test year period but prior to the tariff operation of law date.[24]

12. A normalization adjustment is an adjustment made to reflect normal, on-going operations of the utility. Revenues or costs that were incurred in the test year that are determined to be atypical or abnormal will get specific rate treatment and generally require some type of adjustment to reflect normal or typical operations. The normalization process removes abnormal or unusual events from the cost of service calculations and replaces those events with normal levels of revenues or costs.[25]

13. An annualization adjustment is made to a cost or revenue shown on the utility's books to reflect a full year's impact of that cost or revenue.[26]

14. The calculated total revenue requirement is then compared to net income available from existing rates to determine the incremental change in KCPL's rate revenues required to cover its operating costs and provide a fair return on investment used in providing utility service.[27]

15. The Commission finds that any given witness's qualifications and overall credibility are not dispositive as to each and every portion of that witness's testimony. The

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[22] *Id.* at p. 18.
[23] *Id.* at p. 20.
[24] *Id.* at p. 20-21.
[25] *Id.* at p. 23-24.
[26] *Id.* at p. 22.
[27] *Id.* at p. 27.



ACC-D-2

Commission gives each item or portion of a witness's testimony individual weight based upon the detail, depth, knowledge, expertise, and credibility demonstrated with regard to that specific testimony. Consequently, the Commission will make additional specific weight and credibility decisions throughout this order as to specific items of testimony as is necessary.[28]

16. Any finding of fact reflecting that the Commission has made a determination between conflicting evidence is indicative that the Commission attributed greater weight to that evidence and found the source of that evidence more credible and more persuasive than that of the conflicting evidence.[29]

**B. General Conclusions of Law**

KCPL is an "electrical corporation" and a "public utility" as defined in Sections 386.020(15) and 386.020(43), RSMo, respectively, and as such is subject to the personal jurisdiction, supervision, control and regulation of the Commission under Chapters 386 and 393 of the Missouri Revised Statutes. The Commission's subject matter jurisdiction over KCPL's rate increase request is established under Section 393.150, RSMo.

Sections 393.130 and 393.140, RSMo, mandate that the Commission ensure that all utilities are providing safe and adequate service and that all rates set by the Commission are just and reasonable. Section 393.150.2, RSMo, makes clear that at any hearing involving a requested rate increase the burden of proof to show the proposed increase is just and reasonable rests on the corporation seeking the rate increase. As the party

[28] Witness credibility is solely a matter for the fact-finder, "which is free to believe none, part, or all of the testimony". *State ex rel. Public Counsel v. Missouri Public Service Comm'n*, 289 S.W.3d 240, 247 (Mo. App. 2009).
[29] An administrative agency, as fact finder, also receives deference when choosing between conflicting evidence. *State ex rel. Missouri Office of Public Counsel v. Public Service Comm'n of State*, 293 S.W.3d 63, 80 (Mo. App. 2009)

requesting the rate increase, KCPL bears the burden of proving that its proposed rate increase is just and reasonable. In order to carry its burden of proof, KCPL must meet the preponderance of the evidence standard.[30] In order to meet this standard, KCPL must convince the Commission it is "more likely than not" that KCPL's proposed rate increase is just and reasonable.[31]

In determining whether the rates proposed by KCPL are just and reasonable, the Commission must balance the interests of the investor and the consumer.[32] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[33]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate,

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[30] *Bonney v. Environmental Engineering, Inc.*, 224 S.W.3d 109, 120 (Mo. App. 2007); *State ex rel. Amrine v. Roper*, 102 S.W.3d 541, 548 (Mo. banc 2003); *Rodriguez v. Suzuki Motor Corp.*, 936 S.W.2d 104, 110 (Mo. banc 1996), citing to, *Addington v. Texas*, 441 U.S. 418, 423, 99 S.Ct. 1804, 1808, 60 L.Ed.2d 323, 329 (1979).
[31] *Holt v. Director of Revenue, State of Mo*., 3 S.W.3d 427, 430 (Mo. App. 1999); *McNear v. Rhoades*, 992 S.W.2d 877, 885 (Mo. App. 1999); *Rodriguez v. Suzuki Motor Corp*., 936 S.W.2d 104, 109 -111 (Mo. banc 1996); *Wollen v. DePaul Health Center*, 828 S.W.2d 681, 685 (Mo. banc 1992).
[32] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).
[33] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

> under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[34]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[35]

In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[36]

Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[37]

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[34] *Bluefield,* at 692-93.
[35] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).
[36] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).
[37] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

# III. Disputed Issues

## A. Cost of capital

### Findings of Fact

17. Four financial analysts offered recommendations regarding an appropriate cost of capital in this case. Robert B. Hevert testified on behalf of KCPL. Hevert is Managing Partner of Sussex Economic Advisors, LLC. He holds a Bachelor of Science degree in Finance from the University of Delaware and a Master of Business Administration with a concentration in finance from the University of Massachusetts. He also holds the Chartered Financial Analyst designation.[38] He recommends the Commission allow KCPL a return on equity of 10.3 percent, within a range of 10.0 percent to 10.6 percent.[39]

18. Michael Gorman testified on behalf of Missouri Industrial Energy Consumers ("MIEC") and Midwest Energy Consumers Group ("MECG"). Gorman is a consultant in the field of public utility regulation and is a managing principal of Brubaker & Associates. He holds a Bachelor of Science degree in Electrical Engineering from Southern Illinois University and a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[40] Gorman recommends the Commission allow KCPL a return on equity of 9.10 percent, within a recommended range of 8.80 percent to 9.40 percent.[41]

19. Maureen L. Reno testified on behalf of the U.S. Department of Energy and the Federal Executive Agencies. Reno holds a Bachelor of Arts in Economics from the University of Maine at Orono, Maine and a Master of Arts in Economics from the University of New Hampshire in Durham, New Hampshire. She is employed as an independent

[38] Ex. 115, Hevert Direct, p. 1; Attachment A.
[39] Ex. 116, Hevert Rebuttal, p. 2.
[40] Ex. 550, Gorman Direct, p. 1; Attachment A.
[41] *Id.* at p. 2.

consultant.[42] Reno recommends the Commission allow KCPL a return on equity of 9.0 percent, within a recommended range of 8.2 percent to 9.6 percent.[43]

20. Zephania Marevangepo testified on behalf of Staff. Marevangepo is employed by the Commission as a Utility Regulatory Auditor III in the Financial Analysis Unit. Marevangepo holds a Bachelor of Science degree in Business Administration from Columbia College in Columbia, Missouri and a Masters of Business Administration from Lincoln University in Jefferson City, Missouri.[44] Marevangepo recommends a return on equity of 9.25 percent, within a range of 9.00 percent to 9.50 percent.[45]

21. An essential ingredient of the cost-of-service ratemaking formula is the rate of return, which is premised on the goal of allowing a utility the opportunity to recover the costs required to secure debt and equity financing. If the allowed rate of return is based on the costs to acquire capital, then it is synonymous with the utility's weighted average cost of capital, which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. In order to arrive at a rate of return, the Commission must examine an appropriate ratemaking capital structure, KCPL's embedded cost of debt, and KCPL's cost of common equity, or return on equity.[46]

22. The actual capital structure of Great Plains Energy Incorporated ("GPE") as of May 31, 2015, was 50.090 percent common equity, .552 percent preferred stock, and 49.358 percent long-term debt.[47] This capital structure is consistent with the capital structure of utility operating companies held by proxy companies.[48]

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[42] Ex. 700, Reno Direct, p. 1.
[43] *Id.* at p. 4.
[44] Ex. 200, Staff Report- Revenue Requirement Cost of Service, Appendix 1, p. 75.
[45] Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 19.
[46] Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 18, 37.
[47] Ex. 166, Klote True-Up Rebuttal, p. 2.
[48] Ex. 115, Hevert Direct, p. 54-55.

23. In KCPL's last rate case, File No. ER-2012-0174, the Commission used a consolidated capital structure and embedded cost of debt for KCPL consistent with that of GPE, KCPL's parent company.[49]

24. In KCPL's most recent retail rate case in Kansas, the Kansas Corporation Commission approved the use of a capital structure based on the GPE consolidated capital structure.[50]

25. All of the expert witnesses on this issue recommended using the GPE capital structure for KCPL, except for witness Maureen Reno.[51] Ms. Reno used KCPL's actual capital structure as of December 31, 2014, which included short-term debt.[52]

26. The consolidated cost of long-term debt of GPE as of May 31, 2015, was 5.557 percent.[53] KCPL's weighted average coupon rate for KCPL's debt instruments is consistent with the prevailing market conditions at the time of issuance.[54]

27. Excluding short-term debt from the capital structure is consistent with the Federal Energy Regulatory Commission ("FERC") Order 561, which set forth the formula for calculating the allowance for funds used during construction. Since short-term debt is first used to fund construction work in progress, that same debt cannot be included in the regulatory capital structure without double-counting that debt.[55]

28. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and through stock price appreciation. To comply with standards established by the United States Supreme Court, the Commission must authorize a return on equity sufficient to

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[49] Ex. 200, Staff Report- Revenue Requirement Cost of Service*.* p. 37; Ex. 115, Hevert Direct, p. 53.
[50] Ex. 116, Hevert Rebuttal, p. 64; Transcript, Vol. 9, p. 235.
[51] Transcript, Vol. 9, p. 234-35.
[52] Ex. 700, Reno Direct, p. 10.
[53] Ex. 166, Klote True-Up Rebuttal, p. 2.
[54] Ex. 700, Reno Direct, p. 52.
[55] Ex. 116, Hevert Rebuttal, p. 64.

maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[56]

29. Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow ("DCF") method is based on a theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the cost of equity as the discount rate that sets the current price equal to expected cash flows.[57] The analysts also use variations of the DCF model including the multi-stage growth DCF and the sustainable growth DCF.[58] The Risk Premium method is based on the principle that investors require a higher return to assume a greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations.[59] The Capital Asset Pricing Method ("CAPM") assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.[60] No one method is any more correct than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

30. State public utility commissions in the country are reducing authorized returns on equity to follow the significant decline in capital market costs. A comparison of industry authorized returns on equity indicates that they have been steadily declining over the last

[56] Ex. 550, Gorman Direct, p. 11.
[57] Ex. 115, Hevert Direct, p. 15.
[58] Ex. 550, Gorman Direct, p. 11.
[59] *Id.* at p. 27.
[60] *Id.* at p. 33.

several years. In calendar year 2014, the industry authorized return on equity for fully litigated cases was 9.63 percent. In the first quarter of 2015, the industry authorized return on equity for fully litigated cases was 9.57 percent.[61] Witness Gorman states credibly that based on returns awarded by other commissions, a reasonable finding for a return on equity in this case is conservatively at 9.5 percent or less.[62]

31. The Commission mentions the industry authorized return on equity because KCPL must compete with other utilities all over the country for the same capital. Therefore, the industry authorized return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

32. In its decision regarding KCPL's last rate case, the Commission established a return on equity of 9.7 percent.[63] Over the last four years, the market capital costs for Missouri electric utilities are significantly lower, due to increases in utility stock prices and decreases in bond yields and utility dividend yields.[64]

33. KCPL's expert witness, Robert Hevert, supports an increased return on equity at 10.3 percent. The Commission finds that such a return on equity would be excessive. Hevert's return on equity estimate is high because 1) his constant growth DCF results are based on excessive and unsustainable long-term growth rates, 2) his multi-stage DCF is based on a flawed accelerated dividend cash flow timing and an inflated gross domestic product growth estimate as a proxy for long-term sustainable growth, 3) his CAPM is based

[61] Ex. 552, Gorman Surrebuttal, p. 3, Schedule MPG-SR-1.
[62] Ex. 552, Gorman Surrebuttal, p. 4.
[63] Report and Order, *In the Matter of Kansas City Power & Light Company's Request for Auth. to Implement A Gen. Rate Increase for Elec. Serv. & in the Matter of KCP&L Greater Missouri Operations Company's Request for Auth. to Implement A Gen. Rate Increase for Elec. Serv.*, ER-2012-0174, 2013 WL 299322 (Jan. 9, 2013).
[64] Transcript, Vol. 9, p. 265, 279-80.

on inflated market risk premiums, and 4) his bond yield plus risk premium is based on inflated utility equity risk premiums.[65]

34. If a fuel adjustment clause is implemented in this case, it will reduce KCPL's prospective investment risk, and this risk reduction should be considered in establishing a reasonable return on equity for KCPL.[66]

35. Since April 2015, some capital market and general economic indicators have changed, indicating expanding macroeconomic growth and increased required returns.[67]

36. The return on equity recommendations of witnesses Gorman, Marevangepo, and Reno are all reasonable and an accurate estimate of the current market cost of capital for KCPL, as those recommendations rely on verifiable and independent market data and accepted market-based rate of return models. Gorman testified credibly that these return on equity recommendations demonstrate that KCPL's current cost of equity is 9.5 percent or less.[68]

## Conclusions of Law and Decision

In determining the rate of return, the Commission must first consider KCPL's capital structure and cost of debt. This Commission has historically used the actual capital structure of GPE in determining the capital structure of KCPL, as has the Kansas Corporation Commission when setting KCPL's rates in that state. It is appropriate to use a consistent capital structure across all regulatory jurisdictions to avoid disagreements about one operating company's capital structure having more or less equity than another operating company. Ms. Reno's testimony was not persuasive that short-term debt should be included in the capital structure. The Commission concludes that in calculating KCPL's

[65] Ex. 551, Gorman Rebuttal, p. 6-7, 9-24.
[66] Ex. 552, Gorman Surrebuttal, p. 13.
[67] Ex. 117, Hevert Surrebuttal, p. 46-47.
[68] Ex. 552, Gorman Surrebuttal, p. 2.

cost of capital, the correct capital structure to use is the actual capital structure of GPE as of May 31, 2015, which was 50.090 percent common equity, .552 percent preferred stock, and 49.358 percent long-term debt. The use of short-term debt is not appropriate, so the correct cost of debt for KCPL is its actual cost of long-term debt as of May 31, 2015, which was 5.557%.

In order to set a fair rate of return for KCPL, the Commission must determine the weighted cost of each component of the utility's capital structure. One component at issue in this case is the estimated cost of common equity, or the return on equity. Estimating the cost of common equity capital is a difficult task, as academic commentators have recognized.[69] Determining a rate of return on equity is imprecise and involves balancing a utility's need to compensate investors against its need to keep prices low for consumers.[70]

Missouri court decisions recognize that the Commission has flexibility in fixing the rate of return, subject to existing economic conditions.[71] "The cases also recognize that the fixing of rates is a matter largely of prophecy and because of this commissions, in carrying out their functions, necessarily deal in what are called 'zones of reasonableness', the result of which is that they have some latitude in exercising this most difficult function."[72] Moreover, the United States Supreme Court has instructed the judiciary not to interfere when the Commission's rate is within the zone of reasonableness.[73]

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[69] See Phillips, *The Regulation of Public Utilities*, Public Utilities Reports, Inc., p. 394 (1993).
[70] *State ex rel. Pub. Counsel v. Pub. Serv. Comm'n*, 274 S.W.3d 569, 574 (Mo. Ct. App. 2009).
[71] *State ex rel. Laclede Gas Co. v. Public Service Commission*, 535 S.W.2d 561, 570-571 (Mo. App. 1976).
[72] *State ex rel. Laclede Gas Co. v. Public Service Commission*, 535 S.W.2d 561, 570 -571 (Mo. App. 1976). In fact, for a court to find that the present rate results in confiscation of the company's private property, that court would have to make a finding based on evidence that the present rate is outside of the zone of reasonableness, and that its effects would be such that the company would suffer financial disarray. *Id*.
[73] *State ex rel. Public Counsel v. Public Service Commission*, 274 S.W.3d 569, 574 (Mo. App. 2009). *See, In re Permian Basin Area Rate Cases,* 390 U.S. 747, 767, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968) ("courts are without authority to set aside any rate selected by the Commission [that] is within a 'zone of reasonableness' ").

The evidence shows that return on equity recommendations of witnesses Gorman, Marevangepo, and Reno are all reasonable and an accurate estimate of the current market cost of capital for KCPL. The ranges of those recommendations overlap, and the upper end of those ranges is between 9.4 percent and 9.6 percent. The Commission finds that witness Gorman testified credibly and persuasively that KCPL's current cost of equity is 9.5 percent or less. The Commission has considered other factors, such as recent indicators of growth that may suggest an increased return, and the reduction of investment risk to KCPL by approving a fuel adjustment clause, which suggests a reduced return. However, based on the competent and substantial evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, the Commission concludes that 9.5 percent is a fair and reasonable return on equity for KCPL. This rate of return will allow KCPL to compete in the capital market for the funds needed to maintain its financial health.

## B. Fuel adjustment clause

**2005 stipulation and agreement**

### Findings of Fact

37. A fuel adjustment clause ("FAC") is a mechanism established in a general rate case that allows periodic rate adjustments, outside a general rate proceeding, to reflect increases and decreases in an electric utility's prudently incurred fuel and purchased power costs.[74]

38. While the three other investor-owned electric utilities in Missouri have FACs in place, KCPL does not have an FAC.[75] In File No. EO-2005-0329, the Commission approved

[74] Commission Rule 4 CSR 240-20.090(1)(C).
[75] Ex. 134, Rush Direct, p. 9.

a stipulation and agreement which included an Experimental Regulatory Plan ("2005 Stipulation"). That 2005 Stipulation included a provision that stated:

> KCPL agrees that, prior to June 1, 2015, it will not seek to utilize any mechanism authorized in current legislation known as "SB 179" or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors. In exchange for this commitment, the Signatory Parties agree that if KCPL proposes an Interim Energy Charge ("IEC") in a general rate case filed before June 1, 2015 in accordance with the following parameters, they will not assert that such proposal constitutes retroactive ratemaking or fails to consider all relevant factors:…[76] (emphasis added)

39. The 2005 Stipulation, including the above provision, was approved by the Commission in its Report and Order issued on July 28, 2005. The Report and Order directed that the signatory parties, including KCPL, shall abide by all of the terms and requirements in the 2005 Stipulation.[77]

40. Senate Bill 179 was passed by the Missouri General Assembly, signed by the Governor, and became effective on January 1, 2006. This bill became section 386.266, RSMo, which authorizes electrical corporations to apply to the Commission for an FAC.[78]

41. In Missouri, public utilities must file tariff sheets with the Commission with a specific effective date that determines when rates can first be charged or programs contained on those tariff sheets can be implemented.[79] The tariff sheets KCPL filed in this case for an FAC cannot be used by KCPL until the Commission approves an FAC tariff.[80]

[76] Ex. 200, Staff Report, Revenue Requirement Cost of Service, p. 189-90; Ex. 153.
[77] Report and Order, EO-2005-0329, *In Re Kansas City Power & Light Co.*, 13 Mo. P.S.C. 3d 568, 242 P.U.R.4th 492 (July 28, 2005).
[78] Ex. 152.
[79] Transcript, Vol. 18, p. 1652.
[80] *Id.* at p. 1653-54.

42. Since KCPL's last rate increase went into effect on January 26, 2013, KCPL's costs related to fuel, purchased power, and transmission have all increased substantially, while actual revenues have decreased. KCPL had to absorb these increased costs.[81]

43. While the Commission authorized a return on equity of 9.7% for KCPL's Missouri operations, KCPL was only able to earn a return on equity of 6.5% in 2013, primarily as a result of increases in fuel, purchased power and transmission costs.[82]

44. Without an adequate mechanism to timely recover these cost increases, KCPL will not have a reasonable opportunity to earn its authorized return on equity in the foreseeable future.[83] Because of regulatory lag, it is unlikely that these cost increases could be recovered through a normal rate case.[84]

45. KCPL competes for credit with other vertically-integrated electric utilities in the Midwest and throughout the country, the vast majority of which already have FACs. KCPL's inability to recover its costs, over time, could undermine its financial health and compromise cash flows, which would jeopardize its ability to compete for capital, maintain service levels, and invest in its system. The resulting increased capital costs could potentially lead to increased costs to customers.[85]

46. On June 10, 2015, Missouri Industrial Energy Consumers and the Office of the Public Counsel filed a Motion to Strike Pleadings, Reject Tariff Sheets, and Strike Testimony, to remove from the record portions of KCPL's evidence and reject tariff its sheets in support of its request for an FAC, based on the allegation that KCPL violated the 2005 Stipulation and the Commission's Report and Order in EO-2005-0329. At the

[81] Ex. 134, Rush Direct, p. 6, 12.
[82] *Id.* at p. 12.
[83] *Id.* at p. 7.
[84] *Id.* at p. 14.
[85] *Id.* at p. 8.

evidentiary hearing, the regulatory law judge deferred a ruling on the motion and took the motion with the case.[86]

**Conclusions of Law and Decision**

All parties other than KCPL have expressed the position that KCPL has violated the terms of the 2005 Stipulation provision stated above that prohibits KCPL from seeking to utilize a mechanism such as an FAC prior to June 1, 2015. They argue that by filing the rate case and tariff sheets requesting approval of an FAC before June 1, 2015, KCPL is improperly seeking to utilize an FAC before that date. KCPL argues that it has complied with the 2005 Stipulation because if the Commission authorizes an FAC for KCPL, any tariff approving the use of that FAC will not become effective until after June 1, 2015.

The Commission is a body of limited jurisdiction and has only such powers as are expressly conferred upon it by the statutes and powers reasonably incidental thereto.[87] The Commission cannot enforce, construe or annul contracts,[88] nor can it declare or enforce principles of law or equity.[89] However, the "Commission is entitled to interpret its own orders and to ascribe to them a proper meaning and, in so doing, the Commission does not act judicially but as a fact-finding agency".[90] The Commission's Report and Order in EO-2005-0329 approved the 2005 Stipulation and ordered the signatory parties, including KCPL, to abide by its terms. In determining whether KCPL has complied with that Commission order to abide by the terms of the 2005 Stipulation, the Commission has the authority to interpret the meaning of the provision of the 2005 Stipulation in dispute.

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[86] Transcript, Vol. 9, p. 19.
[87] *State ex rel. & to Use of Kansas City Power & Light Co. v. Buzard*, 350 Mo. 763, 766, 168 S.W.2d 1044, 1046 (1943).
[88] *Wilshire Const. Co. v. Union Elec. Co.*, 463 S.W.2d 903, 905 (Mo. 1971).
[89] *State ex rel. Cass County v. Pub. Serv. Comm'n,* 259 S.W.3d 544, 547 (Mo. App. 2008).
[90] *State ex rel. Beaufort Transfer Co. v. Public Service Commission of Missouri,* 610 S.W.2d 96, 100 (Mo. App. 1980).

The 2005 Stipulation was a settlement agreement, and Missouri courts generally treat settlement agreements as contracts.[91] "The primary rule in the interpretation of a contract is to ascertain the intent of the parties and to give effect to that intent."[92] "Where there is no ambiguity in the contract, the intent of the parties is to be gathered from it alone, and the court will not resort to construction where the intent of the parties is expressed in clear and unambiguous language as there is nothing to construe. The intent of the parties shall be determined from the instrument alone."[93] "Contract language is ambiguous when there is uncertainty as to its meaning and it is fairly susceptible to more than one meaning so that reasonable persons may fairly and honestly differ on construction of its terms."[94] "Words are not ambiguous merely because their meaning and application confound the parties."[95]

KCPL argues that "seek to utilize" is not ambiguous, and that under the plain and ordinary meaning of those words, it means in the context of a rate case that KCPL is prohibited from having an FAC go into effect prior to June 1, 2015, regardless of when the request is filed. The other parties argue that KCPL's interpretation is incorrect, and that by filing its rate case on October 30, 2014, KCPL was improperly seeking to utilize an FAC in violation of the 2005 Stipulation. The dictionary is a good source for finding the plain and ordinary meaning of contract language, but it is important to consider the contract's context in applying the appropriate definition.[96] The dictionary defines "seek" as "to make an

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[91] *State ex rel. Missouri Cable Telecommunications Ass'n v. Missouri Pub. Serv. Comm'n*, 929 S.W.2d 768, 774 (Mo. Ct. App. 1996).
[92] *Speedie Food Mart, Inc. v. Taylor,* 809 S.W.2d 126, 129 (Mo.App.1991).
[93] *Marshall v. Pyramid Dev. Corp.*, 855 S.W.2d 403, 406 (Mo. Ct. App. 1993), citing *Wickham v. Wickham,* 750 S.W.2d 544, 546 (Mo.App.1988) and *Republic Nat. Life Ins. Co. v. Missouri State Bank & Trust Co.,* 661 S.W.2d 803, 808 (Mo.App.1983).
[94] *DCW Enterprises, Inc. v. Terre du Lac Ass'n, Inc.*, 953 S.W.2d 127, 130 (Mo. App. 1997), citing *Clampit v. Cambridge Phase II Corp.,* 884 S.W.2d 340 (Mo.App.1994).
[95] *Bailey v. Federated Mut. Ins. Co.*, 152 S.W.3d 355, 357 (Mo. App. 2004).
[96] *Id.*

attempt: TRY – used with an infinitive”[97], and “utilize” is defined as “to make useful … make use of”.[98] So, under those definitions, seeking to utilize an FAC means to “try to make use of” an FAC. In the context of a rate case, it is clear that KCPL cannot try to make use of an FAC until the Commission has approved tariffs authorizing that mechanism. If the Commission issues a report and order authorizing an FAC, KCPL will file tariffs in compliance with that order to implement the FAC. Those compliance tariffs would both be requested and have an effective date after June 1, 2015.

The Commission finds that terms of the 2005 Stipulation are not ambiguous, so there is no need to apply the rules of contract construction. Using the plain and ordinary meaning of the words in the 2005 Stipulation provision at issue, the filing of KCPL’s rate case on October 30, 2014, did not seek to utilize an FAC prior to June 1, 2015. Therefore, the Commission concludes that KCPL did not violate the terms of the 2005 Stipulation, and it has not violated the Commission’s Report and Order approving that agreement. As a result of this conclusion, the Commission will deny the Motion to Strike Pleadings, Reject Tariff Sheets, and Strike Testimony filed by Missouri Industrial Energy Consumers and the Office of the Public Counsel.

Even assuming for the sake of argument that KCPL violated the 2005 Stipulation, the Commission is not a signatory to that agreement and is not bound by its terms. The Commission may determine for reasons of public policy and public interest that KCPL should be granted an FAC even if it did violate the 2005 Stipulation. The evidence shows that KCPL’s costs related to fuel, purchased power, and transmission have all increased substantially while actual revenues have decreased, resulting in KCPL’s inability to earn its authorized return on equity. KCPL’s inability to recover its costs, over time, could

[97] Webster’s Third New International Dictionary-Unabridged, 2055 (1986).
[98] *Id.* at p. 2525.

undermine its financial health and compromise cash flows, which would jeopardize its ability to compete for capital, maintain service levels, and invest in its system. The resulting increased capital costs could potentially lead to increased costs to customers. Since an FAC is a mechanism that would help KCPL to timely recover its increased costs for fuel, purchased power and transmission and to avoid the negative consequences of regulatory lag, the Commission concludes that, for reasons of public policy, if KCPL meets the criteria for an FAC it should be granted such authority.

**FAC criteria**

## Findings of Fact

47. Fuel used by KCPL to generate electricity is comprised mainly of coal, nuclear, natural gas and oil, and its costs for fuel and transportation alone are of such a magnitude that they would materially impact the utility.[99]

48. The price of coal, natural gas, nuclear fuel, and oil, as well as the associated transportation costs, are established by national or international markets, so KCPL does not have control over commodity prices.[100] KCPL cannot control the fundamentals that drive the short and long-term fuel markets, so fuel costs are beyond the control of KCPL's management.[101]

49. Since January 2004, the price for natural gas has ranged from $1.91/million British thermal units ("MMBtu") to $15.38, which is a range of seven times the lowest price. In April 2012, natural gas prices were as low as $1.91/MMBtu, but by February 2014 those

[99] Ex. 200, Staff Report-Revenue Requirement Cost of Service, p. 197.
[100] *Id.*
[101] Ex. 103, Blunk Direct, p. 23-24.

prices had more than tripled to $6.15. In the six months from February to August of 2015 the price for natural gas dropped almost 40%.[102]

50. Coal prices experienced price changes similar to natural gas. In June 2012, coal prices were $.40/MMBtu. In fewer than two years, the price had almost doubled to $.76/MMBtu. Just a few months after reaching that high in April 2014, the price had dropped 17% to $.63/MMBtu.[103]

51. KCPL's hedging program can manage some of the short-term volatility in coal prices, but this does not protect against long-term market shifts or trends.[104]

52. For the period of 2016 through 2019, the approximate time that an FAC would operate, only a fraction of KCPL's coal requirements are currently under contract.[105]

53. KCPL's net energy costs were more volatile than 13 of the 14 companies in the proxy group used in KCPL's cost of capital analysis, and more volatile than Missouri's three other electric utilities that have FACs.[106]

## **Conclusions of Law and Decision**

Section 386.266.1, RSMo, allows the Commission to establish an FAC for KCPL. Commission Rule 4 CSR 240-20.090(2)(C) states, in part, that:

> In determining which cost components to include in a RAM[107], the commission will consider, but is not limited to only considering, the magnitude of the costs, the ability of the utility to manage the costs, the volatility of the cost component and the incentive provided to the utility as a result of the inclusion or exclusion of the cost component.

The evidence shows that KCPL's fuel and transportation costs are of such a magnitude that they would materially impact the utility, that those fuel costs are beyond the

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[102] *Id.* at p. 21-22.
[103] *Id.* at p. 22.
[104] Id.
[105] Ex. 104, Blunk Rebuttal, p. 9-10.
[106] *Id.* at 23-24.
[107] A "RAM" is a rate adjustment mechanism.

control of KCPL's management, and that its fuel costs are volatile. In addition, Section 386.266.4, RSMo, provides that an FAC must be "reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity". Permitting KCPL to establish an FAC will assist the company in earning its authorized return on equity. The Commission concludes that KCPL has met the criteria for the Commission to authorize an FAC and, therefore, KCPL should be allowed to establish a fuel adjustment clause.

**FAC tariff provisions**

1. **What percentage (customers/company) of changes in costs and revenues should the Commission find appropriate to flow through the fuel adjustment clause?**

## Findings of Fact

54. KCPL is requesting 100% recovery of the costs included in its proposed FAC.[108]

55. Staff is recommending 95%/5% sharing, where customers would be responsible for, or receive the benefit of, 95% of any deviation in fuel and purchased power costs as defined in the FAC tariff from the base amount included in rates.[109]

56. The other three regulated electric utilities in Missouri have FACs that provide for 95%/5% sharing from the customers of those companies.[110]

57. Customers are the parties with the least amount of control over the cost of acquisition and supply of fuel used to generate electricity. KCPL's requested 100% recovery of costs might act as a disincentive to manage its fuel expense properly.[111]

[108] Ex. 208, Eaves Rebuttal, p. 8.
[109] *Id.*
[110] *Id.*
[111] *Id.*

## Conclusions of Law and Decision

Under Missouri law, the Commission is authorized to approve rate schedules for an FAC and may include "features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities".[112] The Commission finds that allowing KCPL to have 100% recovery of its costs in an FAC would act as a disincentive for KCPL to control those costs. A 95%/5% sharing mechanism, where customers would be responsible for, or receive the benefit of, 95% of any deviation in fuel and purchased power costs would provide KCPL a sufficient opportunity to earn a fair return on equity while protecting KCPL's customers by providing the company an incentive to control costs. KCPL's FAC shall include an incentive clause providing that 95% of any deviation in fuel and purchased power costs from the base level shall be passed to customers and 5% shall be retained by KCPL.

2. **Should the costs and revenues that are to be included in the FAC be approved by the Commission and explicitly identified along with the FERC account, subaccount and the resource code in which KCPL will record the actual cost/revenue? If so, what costs and revenues should be included and what are their corresponding FERC accounts, subaccounts and resource codes?**

3. **Should the FAC tariff sheets reflect the accounts, subaccounts, resource codes, and the cost/revenue description?**

## Findings of Fact

58. No additional findings of fact are necessary, as this is essentially a policy question for Commission determination.

## Conclusions of Law and Decision

No party disagrees that the Commission should approve costs and revenues to be included in the FAC. The Commission determines that the FAC tariff sheets should identify

[112] Section 386.266.1, RSMo.

costs and revenues by FERC account and subaccount, but that the use of corporate resource codes is not necessary.

**4. Should Southwest Power Pool ("SPP") and other regional transmission organization/independent system operator transmission fees be included in the FAC, and at what level?**

## Findings of Fact

59. KCPL is a member of SPP, a regional transmission organization ("RTO"). As of March 1, 2014, SPP implemented its Integrated Marketplace ("IM"), in which SPP is responsible for the market operations of its participants and generating resources.[113]

60. KCPL buys back energy from SPP to meet the needs of its customers. The price at which KCPL purchases energy from the market will be at a rate set by SPP that reflects a market price.[114]

61. On a daily basis, KCPL sells all of the power it generates into the SPP market and purchases from SPP 100% of the electricity it sells to its retail customers.[115]

62. KCPL requests that transmission costs associated with the charges and revenues from SPP billings, and transmission costs to buy and sell energy, be recovered in rates through the FAC mechanism. KCPL is proposing that standard point-to-point transmission charges and base plan funding in FERC account 565 be included.[116]

63. KCPL is proposing to place all of its wholesale transmission expenses and revenues into its FAC, not just those that are for the transportation of purchased power.[117]

[113] Ex. 200, Staff Report-Revenue Requirement Cost of Service, p. 198.
[114] *Id.*
[115] Ex. 107, Carlson Rebuttal, p. 9.
[116] Ex. 134, Rush Direct, p. 17, 22.
[117] Ex. 557, Dauphinais Rebuttal, p. 7-8.

64. The only transportation costs for purchased power that KCPL incurs are its wholesale transmission expenses that are incurred to transmit power it has purchased from SPP or other third parties.[118]

65. KCPL's wholesale transmission expenses incurred to transmit power from its own generation resources to its own load are not incurred for transportation of fuel or purchased power.[119]

66. KCPL generally does not incur wholesale transmission expenses to make off-system sales to SPP or to any third party located within SPP. Pursuant to the SPP tariff, KCPL generally only incurs wholesale transmission expenses for off-system sales when those sales are to third parties located outside of SPP.[120]

67. Only approximately 7.3% of KCPL's total SPP wholesale transmission expenses can be reasonably classified as being for transportation of fuel or purchased power.[121]

68. KCPL's transmission costs have been rising, and projections show that these expenses will continue to increase at a significant rate from 2014 through 2019.[122]

69. While KCPL's transmission costs are increasing, those costs are known, measurable, and not unpredictable, so the costs are not volatile.[123]

## **Conclusions of Law and Decision**

Section 386.266.1, RSMo, allows an electric utility to make periodic rate adjustments only to "reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation". This limits the costs that can be flowed through an FAC for

118 *Id.* at p.8.
119 *Id.*
120 *Id.* at p. 10.
121 *Id.* at p.12.
122 Ex. 134, Rush, Direct, p. 20.
123 *Id.* at p. 11, line 2; Ex. 200, Staff Report-Revenue Requirement Cost of Service, p. 199; Eaves Rebuttal, p. 208; Ex. 209, Eaves Surrebuttal, p. 1-5..

recovery. Transportation costs have been determined to include transmission costs, but limited only to those connected to purchased power costs.[124]

KCPL argues that all of its SPP transmission fees should be included in the FAC because those fees are mandatory, increasing in amount, and volatile. In addition, KCPL states that since all of its power generation is sold into the SPP market and purchased from that market, all SPP expenses and revenues related to those individual sales and purchases of transmission service must be included in the FAC.

The Commission has addressed this issue in recent rate cases. In the Report and Order issued in File No. ER-2014-0258 for Ameren Missouri, the Commission stated:

> The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.
>
> The drafters of the FAC statute likely did not envision a situation where a utility would consider all its generation purchased power or off-system sales. In fact, the policy underlying the FAC statute is clear on its face. The statute is meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power. At the time the statute was drafted, and even in our more complex present-day system, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve it load are the costs that are unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified.
>
> Therefore, of the three reasons Ameren Missouri incurs transmission costs cited earlier, the costs that should be included in the FAC are 1) costs to transmit electric power it did not generate to its own load (true purchased power) and 2) costs to transmit excess electric power it is selling to third parties to locations outside of MISO (off-system sales). Any other interpretation would expand the reach of the FAC beyond its intent.[125]

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[124] *In re Union Elec. Co.*, 422 S.W.3d 358, 367 (Mo. App. 2013).

[125] Report and Order, ER-2014-0258, *In the Matter of Union Elec. Co., d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Elec. Serv.*, 320 P.U.R.4th 330 (Apr. 29, 2015).

Similarly, in a subsequent rate case for The Empire District Electric Company, which is also a member of SPP, the Commission concluded:

> Furthermore, as has been the case since the FAC statute was created, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve its load are the costs that are unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified. Therefore, the costs Empire incurs related to transmission that are appropriate for the FAC, from a policy perspective and by statute, are: 1) Costs to transmit electric power it did not generate to its own load ("true purchased power"); or 2) Costs to transmit excess electric power it is selling to third parties to locations outside of its RTO ("Off-system sales").[126]

The evidence shows in this case that on a daily basis, KCPL sells all of the power it generates into the SPP market and purchases from SPP 100% of the electricity it sells to its retail customers. However, based on the Commission's analysis in the two cases cited above, it would not be lawful for KCPL to recover all of its SPP transmission fees through the FAC. In addition, while KCPL's transmission costs are increasing, those costs are known, measurable, and not unpredictable, so the costs are not volatile. The Commission concludes that the appropriate transmission costs to be included in the FAC are 1) costs to transmit electric power it did not generate to its own load (true purchased power); and 2) costs to transmit excess electric power it is selling to third parties to locations outside of SPP (off-system sales).

**5. Should SPP and FERC Administrative fees (SPP Schedule 1-A and 12) be included in the FAC?**

## <u>Findings of Fact</u>

70. SPP Schedule 1-A fees are for SPP expenses associated with administering its Open Access Transmission Tariff. These expenses cover regional scheduling, planning,

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[126] Report and Order, ER-2014-0351, *In the Matter of the Empire Dist. Elec. Co. for Auth. to File Tariffs Increasing Rates for Elec. Serv. Provided to Customers in the Company's Missouri Serv. Area*, ER-2014-0351, 2015 WL 4036220 (June 24, 2015)

and market-monitoring services provided to facilitate the transportation of energy on the transmission system.[127]

71. SPP Schedule 12 fees are an assessment charged by FERC related to KCPL's membership in SPP.[128]

72. Schedule 1-A and 12 fees are administrative in nature and not directly linked to fuel and purchased power costs. These fees support the operation of SPP and are not needed for KCPL to buy and sell energy to meet the needs of its customers.[129]

73. RTO administrative fees, such as Schedule 1-A and 12 fees, are not included in the FACs of other regulated utilities in Missouri.[130]

74. Schedule 1-A and 12 fees are variable, but not volatile in nature.[131]

## **Conclusions of Law and Decision**

KCPL has requested that SPP Schedule 1-A and 12 fees be included in its FAC. The Commission finds that these fees are administrative in nature and not directly linked to fuel and purchased power costs. These fees support the operation of SPP and are not needed for KCPL to buy and sell energy to meet the needs of its customers. These fees are neither fuel and purchased power expenses nor transportation expenses incurred to deliver fuel or purchased power. The Commission concludes that including such fees would be unlawful under Section 386.266.1, RSMo, and, therefore, Schedule 1-A and 12 fees should not be included in the FAC. These fees are appropriate for recovery in base rates.

[127] Ex. 107, Carlson Rebuttal, p. 10.
[128] Ex. 106, Bresette Surrebuttal, p. 6.
[129] Ex. 208, Eaves Rebuttal, p. 9-10.
[130] *Id.*
[131] *Id.*

6. **Should all realized gains and losses from KCPL's hedging and/or cross hedging practices be included in the FAC?**

**Findings of Fact**

75. KCPL has a hedging program to manage the price risk of coal and natural gas. The coal price hedging program involves a strategy of laddering into a portfolio of forward contracts for coal. Laddering refers to purchasing multiple products with different maturity dates. The natural gas hedging program involves the purchase of futures contracts to lock in a future price.[132]

76. KCPL's hedging programs for both of these fuels has helped to avoid much of the volatility in the coal market, as well as exposure to natural gas market price risk.[133]

77. An example of cross-hedging is the use of natural gas futures contracts to hedge electricity prices, since there is not a good market for electricity hedging instruments and the price of each have a strong relationship and move in tandem.[134]

78. Cross-hedges are the best means for hedging power purchases or sales.[135]

79. KCPL has used cross-hedging to achieve a balance in its hedging programs to reduce risk and volatility but does not do so at this time.[136]

**Conclusions of Law and Decision**

KCPL has requested that its realized gains and losses from its hedging programs be included in the FAC. Hedging programs help to avoid volatility in the coal market and limit exposure to natural gas market price risk. Staff does not object to hedging, but opposes cross-hedging power transactions with natural gas because KCPL does not currently utilize cross-hedges. KCPL is persuasive that having the option of using both hedging and cross-

[132] Ex. 103, Blunk Direct, p. 24-32.
[133] *Id.* at p. 25, 31.
[134] Transcript, Vol. 18, p. 1600.
[135] Ex. 104, Blunk Rebuttal, p. 34.
[136] Transcript, Vol. 18. P. 1601-2.

hedging would be valuable to reduce risk and volatility. The Commission concludes that all realized gains and losses from KCPL's hedging and/or cross-hedging practices should be included in the FAC.

**7. Should SO2 amortizations, bio fuels, propane, accessorial charges, broker commissions, fees and margins, be included in the FAC?**

**Findings of Fact**

80. Accessorial charges are a necessary part of transporting coal by rail, including switching and the release and pick-up of locomotive power. This type of charge is included in railroad tariffs.[137]

81. KCPL does not have unique account numbers or resource codes for these costs, so excluding them would increase the administrative and audit burden of the company.[138]

82. $SO_2$ amortizations are collected in FERC account 509.[139]

**Conclusions of Law and Decision**

KCPL has requested that charges for $SO_2$ amortizations, bio fuels, propane, accessorial charges, broker commissions, fees, and margins should be included in the FAC. Staff objects that these terms are not adequately defined, which KCPL has agreed to do. Including an appropriate description of these terms would enable KCPL to operate and Staff to audit the FAC correctly. Since accessorial charges are included in railroad tariffs and $SO_2$ amortizations are collected in FERC account 509, the Commission finds that $SO_2$ amortizations, bio fuels, propane, accessorial charges, broker commissions, fees, and margins should be included in the FAC, but should also be specifically defined within the FAC tariff.

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137 Ex. 104, Blunk Rebuttal, p. 34.
138 *Id.*
139 Ex. 135, Rush Rebuttal, p. 26, responding to Ex. 309, Mantle Direct, p. 30.

**8. Should the FAC include costs and revenues that KCPL is not currently incurring or receiving other than insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC?**

## Findings of Fact

83. Allowing new costs and revenues to flow through an FAC would be a modification to the FAC that the Commission approved.[140]

84. Including a cost or revenue in the FAC that KCPL does not currently incur or record clouds the transparency of the FAC and unnecessarily complicates it.[141]

85. Insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC are revenues typically related to an unexpected incident or accident. If these types of revenues do occur, it is likely that at some point in time, prior to the receipt of the recovery or settlement, there were increased costs or reduced revenues due to that circumstance that have been included in the fuel adjustment rates paid by customers.[142]

## Conclusions of Law and Decision

KCPL argues that the FAC should include all costs and revenues relating to net fuel and purchased power costs, whether or not they are currently being incurred. However, allowing a new cost or revenue to flow through an FAC is a modification to that FAC, which under Section 386.266, RSMo, only the Commission has the authority to modify. It is the Commission that should make the determination as to what costs or revenues should flow through the FAC, not the electric utility. An exception to this would be insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC because such revenue increases are likely the result of circumstances that already

[140] Ex. 309, Mantle Direct, p. 33.
[141] *Id.* at p. 34.
[142] *Id.*

caused additional costs or reduced revenues in the FAC. The Commission concludes that the FAC should not include costs and revenues that KCPL is not currently incurring or receiving, other than insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC.

**9. Does the FAC need to have exclusionary language added to insure that NERC and FERC penalties are not included?**

**Findings of Fact**

86. Staff proposed a change to KCPL's exemplar tariff sheet for an FAC to include a statement that all penalties related to NERC and FERC compliance standards shall be excluded.[143]

87. The FERC Uniform System of Accounts ("USoA") provides guidance that such charges should be recorded in account 557, which is not includible in the FAC, so there could be no recovery of such penalties even if the language proposed by Staff were not included.[144]

**Conclusions of Law and Decision**

Staff and OPC take the position that it would be preferable to include language to exclude NERC and FERC penalties from the FAC to make that completely clear. The Commission concludes that it is not necessary to include this language because the FERC USoA specifically provides that these penalties are not to be included. The proposed language should not be included in the FAC.

[143] Ex. 135, Rush Rebuttal, p. 18-19.
[144] *Id.*

**10. Should the phrase "miscellaneous SPP IM charges, including but not limited to," be included in KCPL's FAC tariff?**

## Findings of Fact

88. KCPL has proposed including in the FAC the phrase "miscellaneous SPP IM charges, including but not limited to," to account for any changes to SPP IM market charge types directed by SPP. The inclusion of the word "miscellaneous" referring to charges is vague.[145]

89. The Commission takes administrative notice of the FAC tariff for Union Electric Company d/b/a Ameren Missouri, which tariff sheets are titled MO. P.S.C. Schedule No. 6, Original Sheet No. 70.1through Original Sheet No. 73.11 and filed with the Commission.

## Conclusions of Law and Decision

The Commission finds that the language proposed by KCPL, which includes the phrase "miscellaneous SPP IM charges, including but not limited to," in the FAC tariff, is too vague and open-ended. The Commission concludes that the FAC tariff for KCPL should include language regarding changes in the SPP IM market charge types substantially similar to the FAC tariff language on that subject found in the FAC tariff for Ameren Missouri in MO. P.S.C. Schedule No. 6, Original Sheet No. 70.1through Original Sheet No. 73.11.

**11. How should OSSR be defined?**

## Findings of Fact

90. KCPL has proposed a definition of revenues from off-system sales ("OSSR"), as follows:

[145] Ex. 209, Eaves Surrebuttal, p. 9.

> The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales. This includes charges and credits related to the SPP Integrated Marketplace including, energy, make whole and out of merit payments and distributions, Over collected losses payments and distributions, TCR and ARR settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non- performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including, but not limited to, uplift charges or credits. It does not include sales for resale – private utilities or sales for resale – municipalities.[146]

91. Staff has proposed a different definition of OSSR, as follows:

> OSSR = Revenues from Off-System Sales:
> The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales. This includes charges and credits related to the SPP Integrated Marketplace including, energy, ancillary services, revenue sufficiency and neutrality payments and distributions, Over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non- performance and distribution payments and SPP uplift revenues or credits. Off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year shall be excluded from OSSR component.[147]

92. Staff's definition of OSSR struck "make whole and out of merit payments and distributions", but added ancillary services, revenue sufficiency, and neutrality.[148]

93. Staff's terminology more accurately describes the type of revenue that should be included in an FAC.[149]

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[146] Ex. 134, Rush Direct, Schedule TMR-4.
[147] Ex. 202, Staff Rate Design & Class Cost of Service Report and erratum, Schedule DEE-1-3.
[148] Ex. 135, Rush Rebuttal, p. 20.
[149] Ex. 209, Eaves Surrebuttal, p. 10.

## Conclusions of Law and Decision

The Commission finds that Staff's definition of OSSR more accurately and specifically describes the type of revenue that should be included in an FAC. The Commission concludes that KCPL's FAC tariff should include Staff's definition of OSSR.

**12. How should the "J" component be defined, i.e., how should "Net System Input" be defined for KCPL's operations?**

## Findings of Fact

94. The "J" component refers to the definition of KCPL's jurisdictional allocation calculation. KCPL proposes that the "J" component be defined as: J = Missouri Retail Energy Ration = Missouri Retail kWh Sales/Total Retail kWh Sales (KS and MO) + Sales for Resale (Account 447.100 – Municipals).[150]

95. Staff proposes that the "J" component be defined as: Missouri Retail Energy Ration = Missouri Retail kWh sales/ Total Net System Input (NSI), where NSI is defined as [Retail Sales (KS+MO) + Sales for Resale + Border Customers + Firm Wholesale + Losses].[151]

96. KCPL's Kansas customers are mostly residential and Missouri customers include more commercial and industrial customers. Typically, a service area composed of residential customers will experience higher line loss percentage than that of a system with a mixture of residential, commercial and industrial customers, such as the Missouri service territory.[152]

## Conclusion of Law and Decision

KCPL's recommendation would be appropriate if line losses are proportional to kWh sales, but line losses between Missouri and Kansas are not proportional based on the

[150] Ex. 135, Rush Rebuttal, p. 20.
[151] *Id.*; Ex. 209, Eaves Surrebuttal, p. 10-11.
[152] Ex. 209, Eaves Surrebuttal, p. 10-11.

current customer mix (residential v. commercial/ industrial). The Commission concludes that Staff's proposed definition of the "J" component is more appropriate and should be included in KCPL's FAC tariff.

**13. Should the rate schedules implementing the FAC have an amount for the Base Factor when the Commission initially approves them, or not until after the end of the first FAC accumulation period?**

## Findings of Fact

97. Both KCPL and Staff agree that an FAC Base Factor must be set in this case and that the Base Factor must be stated in the FAC tariff.[153]

98. Staff recommends that the Base Factor be included both in the body of the FAC tariff and on the "formula" sheet.[154]

99. The actual calculation of the Base Factor will need to be modified to reflect the Commission's final decision in this case.[155]

## Conclusion of Law and Decision

The Commission concludes that the Base Factor, as modified to reflect the Commission's decision in this case, shall be included both in the body of the FAC tariff and on the "formula" sheet.

**14. How many different voltage levels of service should be recognized for purposes of applying loss factors?**

## Findings of Fact

100. KCPL provided to Staff a loss study dated October 29, 2014, which contains system loss calculations and determinations based on data collected during calendar year 2013.[156]

[153] Ex. 209, Eaves Surrebuttal, p. 11; Transcript, Vol. 18, p. 1630-31.
[154] Ex. 202, Staff Rate Design & Class Cost of Service Report and erratum, Schedule DEE-1-6.
[155] Ex. 209, Eaves Surrebuttal, p. 11.
[156] Ex. 200, Staff Report-Revenue Requirement Cost of Service, p. 200.

101. Staff used the information in this loss study in developing its recommended two primary and secondary voltage level adjustment factors.[157]

102. Midwest Energy Consumers Group proposes that KCPL's FAC include four voltage levels, primary, secondary, substation, and transmission.[158]

103. KCPL's loss study does not contain applicable data for losses at the substation level, which is one of the voltage level distinctions recommended by MECG, so that recommendation is not based on the data in the loss study.[159]

## **Conclusion of Law and Decision**

Commission Rule 4 CSR 240-20.090(9) requires an electric utility that desires to implement a rate adjustment mechanism, such as an FAC, to complete a jurisdictional system loss study of the corresponding energy losses experienced in its delivery of electricity. This study must be conducted within 24 months prior to the general rate case in which it requests its rate adjustment mechanism. KCPL's line loss study, required by this Commission rule, does not contain applicable data for losses experienced at the substation level, so recognition of more than two voltage levels is not currently supported by a necessary study. The Commission concludes that for this rate case two different voltage levels of service should be recognized for purposes of applying loss factors.

KCPL is directed to include in its line loss study for its next general rate case the information necessary to allow the parties to consider and evaluate if any additional voltage level adjustment factors should be incorporated into the design of the FAC tariff in KCPL's next rate case.

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[157] *Id.* at p. 200-201.
[158] Ex. 554, Brubaker Direct, p. 7-9.
[159] Ex. 204, Bax Rebuttal, p. 2-3 and Schedule ABJ-1.

**15. What are the appropriate recovery periods and corresponding accumulation periods for the FAC?**

**Findings of Fact**

104. KCPL has proposed recovery periods of October through September and April through March with the corresponding accumulation periods of January through June and July through December. [160] KCPL has indicated that neither Staff nor OPC have any objections to this proposal.

**Conclusion of Law and Decision**

The parties that expressed a position on this issue have agreed that recovery periods of October through September and April through March with the corresponding accumulation periods of January through June and July through December should be included in the FAC. The Commission agrees that these recovery periods and accumulation periods are reasonable and should be included in the FAC.

**16. Should FAC costs and revenues be allocated in the accumulation period's actual net energy cost in a manner consistent with the allocation methodology utilized to set permanent rates in this case?**

**Findings of Fact**

105. KCPL, Staff and OPC agree that FAC costs and revenues should be allocated consistently with the allocation methodology used to set permanent rates.[161]

**Conclusion of Law and Decision**

All parties have agreed that costs and revenues should be allocated consistently with the allocation methodology used to set permanent rates in this case. The Commission concludes that FAC costs and revenues should be allocated in the accumulation period's

[160] Ex. 135, Rush Rebuttal, p. 27.
[161] KCPL initial brief at p. 58; Staff initial brief at p. 58; OPC initial brief at p. 41-42.

actual net energy cost in a manner consistent with the allocation methodology used to set permanent rates in this case.

**17. If the Commission authorizes KCPL to have a fuel adjustment clause, what FAC-related reporting requirements should it order KCPL to comply with?**

## Findings of Fact

106. Staff has proposed that the following information be provided due to the accelerated Staff review process necessary with FAC adjustment filings:

- As part of the information KCPL submits when it files a tariff modification to change its Fuel and Purchased Power Adjustment rate, include KCPL's calculation of the interest included in the proposed rate;
- Maintain at KCPL's corporate headquarters or at some other mutually-agreed-upon place and make available within a mutually-agreed-upon time for review, a copy of each and every coal and coal transportation, natural gas, fuel oil and nuclear fuel contract KCPL has that is in or was in effect for the previous four years;
- Within 30 days of the effective date of each and every coal and coal transportation, natural gas, fuel oil and nuclear fuel contract KCPL enters into, provide both notice to the Staff of the contract and opportunity to review the contract at KCPL's corporate headquarters or at some other mutually-agreed-upon place;
- Provide a copy of each and every KCPL hedging policy that is in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain;
- Within 30 days of any change in a KCPL hedging policy, provide a copy of the changed hedging policy for Staff to retain;
- Provide a copy of KCPL's internal policy for participating in the Southwest Power Pool's Integrated Market;
- Maintain at KCPL's corporate headquarters or at some other mutually-agreed-upon place and make available within a mutually-agreed-upon time for review, a copy of each and every bilateral energy or demand sales/purchase contract;
- If KCPL revises any internal policy for participating in the Southwest Power Pool, within 30 days of that revision, provide a copy of the revised policy with the revisions identified for Staff to retain; and
- The monthly as-burned fuel report supplied by KCPL required by 4 CSR 240-3.190(1)(B) shall explicitly designate fixed and variable components of the average cost per unit burned including commodity, transportation, emission, tax, fuel blend, and any additional fixed or variable costs

associated with the average cost per unit reported (Staff is willing to work with KCPL on the electronic format of this report).[162]

107. KCPL has agreed to provide this information to Staff.[163]

## Conclusion of Law and Decision

Since KCPL does not object to providing the reporting requirements recommended by Staff and listed above, the Commission determines that KCPL shall comply with those reporting requirements.

**18. If the Commission authorizes KCPL to have an FAC, should KCPL be allowed to add cost and revenue types to its FAC between rate cases?**

## Findings of Fact

108. Allowing new cost and revenues types to flow through an FAC would be a modification to the FAC that the Commission approved.[164]

109. Staff has proposed the following FAC tariff language that would permit changes to cost and revenue types:

> Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component FC, E, PP, TC, OSSR or R. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through the Rider FAC are to be recorded in the account.[165]

## Conclusion of Law and Decision

KCPL should not be able to add cost and revenue types to its FAC between rate cases unless the FAC tariff provides for those changes. The Commission concludes that

[162] Ex. 202, Staff Rate Design & Class Cost of Service Report, p. 42-43.
[163] Ex. 135, Rush Rebuttal, p. 17; Transcript, Vol. 18, p. 1700-01.
[164] Ex. 309, Mantle Direct, p. 33.
[165] Ex. 202, Staff Rate Design & Class Cost of Service Report, p. 37 and erratum, Schedule DEE-1.

the tariff provision proposed by Staff above is reasonable and should be included in KCPL's FAC tariff.

**19. If the Commission authorizes KCPL to have a FAC, should KCPL be required to clearly differentiate itself from GMO on customer bills?**

**Findings of Fact**

110. When KCPL and KCP&L Greater Missouri Operations Company ("GMO") were brought under GPE, that company decided to use a single brand, KCPL, for both. At this time, GMO bills only indicate the KCPL brand name.[166]

111. The customer's rate code is present on the bill and would serve to direct the customer to the correct tariffs for each individual company. Customer service employees are available to help customers identify the applicable tariff sheets.[167]

112. Changing the bill language and presentation would not be a trivial undertaking, as space on the bill is limited and can impact various systemic billing processes.[168]

113. There is no evidence in the evidentiary record that demonstrates customer confusion regarding which company provides service.

**Conclusion of Law and Decision**

The evidence shows that although bills for GMO customers do not have that company name on them, there is other information on the bill that would direct a customer to the correct tariff for that company. In addition, customer service employees are available to provide that information, and changing the bills would cause hardship to KCPL. Since there is no evidence of customer confusion, the Commission concludes that KCPL should not be required to clearly differentiate itself from GMO on customer bills.

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[166] Transcript, Vol. 18, p. 1632-33.
[167] Ex. 135, Rush Rebuttal, p. 64.
[168] *Id.*

## C. Transmission fee expense

**Findings of Fact**

114. In Missouri, rates are usually established based upon a historical test year where the company's expenses and the rate base necessary to produce the revenue requirement are synchronized. The deferral of costs from a prior period results in costs associated with the production of revenues in one period being charged against the revenues in a different period, which violates the "matching principle" required by Generally Accepted Accounting Principles (GAAP) and the Uniform System of Accounts approved by the Commission. The matching principle is a fundamental concept of accrual basis accounting, which provides that in measuring net income for an accounting period, the costs incurred in that period should be matched against the revenue generated in the same period. Such matching creates consistency in income statements and balance sheets by preventing distortions of financial statements which present an unfair representation of the financial position of the business. One type of deferral accounting, a "tracker", has the effect of either increasing or decreasing a utility's earnings for a prior period by increasing or decreasing revenues in future periods, which violates the matching principle.[169]

115. A tracker is a rate mechanism under which the amount of a particular cost of service item actually incurred by a utility is tracked and compared to the amount of that item currently included in a utility's rate levels. Any over-recovery or under-recovery of the item in rates compared to the actual expenditures made by a utility is then booked to a regulatory asset or liability account and would be eligible to be included in the utility's rates in its next general rate proceeding through an amortization to expense.[170]

[169] Ex. 312, Robertson Surrebuttal, p. 5-6.
[170] Ex. 235, Oligschlaeger Rebuttal, p. 3.

116. The broad use of trackers should be limited because they violate the matching principle, tend to unreasonably skew ratemaking results, and dull the incentives a utility has to operate efficiently and productively under the rate regulation approach employed in Missouri.[171]

117. KCPL requested a tracker for transmission fees it incurs to send and receive power ("transmission") through the territory of RTOs such as the Southwest Power Pool ("SPP").[172]

118. KCPL's transmission costs have increased over the past several years, but administrative fees charged by SPP are projected to decrease in the future.[173]

119. KCPL's transmission costs are normal, ordinary and recurring operating costs, and not extraordinary.[174]

120. KCPL's correct annualized levels of transmission expense and revenue to recognize in its revenue requirement on a Missouri jurisdictional basis are the highly confidential amounts stated in Ex. 256 HC, Lyons True-Up Rebuttal, p. 14, lines 13-14. These amounts do not include any transmission costs charged to KCPL by reason of Independence Power & Light becoming a member of SPP.

121. In surrebuttal testimony, KCPL requested for the first time that for SPP transmission fees not included in an FAC or afforded tracker treatment, $5 million of annual estimated Missouri jurisdiction SPP transmission fees expense should be added to the revenue requirement above the base amount of Missouri jurisdiction SPP transmission fees. If the forecast amount recognized in revenue requirement exceeds actual SPP

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[171] Ex. 235, Oligschlaeger Rebuttal, p. 7.
[172] Ex. 135, Rush Rebuttal, p. 11
[173] Ex. 223, Lyons Surrebuttal, p. 6
[174] Ex. 223, Lyons Surrebuttal, p. 9.

transmission fee expense during the period rates are in effect, such amounts should be credited to customers in a subsequent rate case.[175]

## **Conclusions of Law and Decision**

The Commission has the statutory authority to prescribe methods for electrical corporations to keep their accounts, records and books.[176] The Commission has set forth such proper methods in Commission Rule 4 CSR 240-20.030, which requires every electrical corporation to keep all accounts in conformity with the Uniform System of Accounts ("USoA") as prescribed by FERC and published at 18 CFR Part 101 (2013). In the USoA, Accounts 182.3 and 254, other regulatory assets and liabilities, describe accounts for recording an item outside the year of occurrence ("deferral") for determination in a later action.[177] The USoA allows deferral for "extraordinary items", which are defined as:

> Those items related to the effects of events and transactions which have occurred during the current period and which are of unusual nature and infrequent occurrence shall be considered extraordinary items. Accordingly, they will be events and transactions of significant effect which are abnormal and significantly different from the ordinary and typical activities of the company, and which would not reasonably be expected to recur in the foreseeable future.[178]

[175] Ex. 136, Rush Surrebuttal, p. 9.
[176] Section 393.140(4), RSMo.
[177] 18 C.F.R. § Pt. 101, Definition 31. Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable:

A. that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or

B. in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required.

[178] 18 C.F.R. § Pt. 101, General Instruction No. 7; See also, Report and Order, ER-2012-0174, *In the Matter of Kansas City Power & Light Company's Request for Auth. to Implement A Gen. Rate Increase for Elec. Serv. & in the Matter of KCP&L Greater Missouri Operations Company's Request for Auth. to Implement A Gen. Rate Increase for Elec. Serv.*, 2013 WL 299322 (Jan. 9, 2013); Report and Order, *In the Matter of the Application of S. Union Co. for the Issuance of an Accounting Auth. Order Relating to Its Natural Gas Operations & for A Contingent Waiver of the Notice Requirement of 4 CSR 240-4.020(2)*, GU-2011-0392, 2012 WL 363727 (Jan. 25, 2012).

KCPL has requested that the Commission approve the use of a particular deferral accounting method, a tracker. This type of deferral accounting to defer costs which may be incurred in the future is similar to an accounting authority order that defers expenses incurred as a result of a past event, in that neither constitute ratemaking. Missouri courts have stated that the granting of an accounting authority order is not ratemaking and creates no expectation of recovery.[179] For example, in a recent rate case, the Commission refused to allow recovery of amounts deferred under a previous accounting authority order.[180] Like an accounting authority order, a tracker simply defers a cost for determination in a future rate case where the Commission may determine whether that cost should be recovered in rates after considering all relevant factors.[181]

KCPL also requested a transmission tracker in its most recent rate case, ER-2012-0174, under a very similar fact situation. That Commission denied that requested tracker, finding that KCPL had failed to demonstrate that the projected cost increases were extraordinary:

> "Rare" does not describe cost increases in the utility business generally. Specifically, Applicants' evidence shows the following as to transmission. Transmission is an ordinary and typical, not an abnormal and significantly different, part of Applicants' activities. Also, Applicants showed that paying more for transmission than in the previous year is a foreseeably recurring event, not an unusual and infrequent event. Thus, "items related to the effects of" transmission cost increases are not rare and, therefore, are not extraordinary.[182]

[179] *State ex rel. Missouri Gas Energy v. Public Serv. Com'n*, 210 S.W.3d 330, 336 (Mo. App. W.D. 2006); *Missouri Gas Energy v. Public Serv. Com'n*, 978 S.W.2d 434, 438 (Mo. App. W.D. 1998). See also, Commission Rule 4 CSR 240-20.030(4), which states, in part, that "[i]n prescribing this system of accounts, the commission does not commit itself to the approval or acceptance of any item set out in any account for the purpose of fixing rates or in determining other matters before the commission."
[180] Report and Order, ER-2014-0258, *In the Matter of Union Elec. Co., d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Elec. Serv.*, 320 P.U.R.4th 330 (Apr. 29, 2015).
[181] Commission Rule 4 CSR 240-20.030(5) does allow the Commission to waive or grant a variance from the provisions of the USoA for good cause shown, but KCPL did not request such a waiver or variance.
[182] Report and Order, ER-2012-0174, *In the Matter of Kansas City Power & Light Company's Request for Auth. to Implement A Gen. Rate Increase for Elec. Serv. & in the Matter of KCP&L Greater Missouri*

The evidence presented in this case showed that KCPL's transmission costs, while having increased in recent years, are normal, ordinary and recurring operation costs. These recurring costs are not abnormal or significantly different from the ordinary and typical activities of the company, so they are not extraordinary and, therefore, not subject to deferral under the USoA. The Commission concludes that KCPL has not met its burden of proof to demonstrate that projected transmission cost increases are extraordinary, so its request for a transmission tracker will be denied.

KCPL's correct annualized levels of transmission expense and revenue to recognize in its revenue requirement on a Missouri jurisdictional basis are the amounts stated in Ex. 256 HC, Lyons True-Up Rebuttal, p. 14, lines 13-14. These amounts do not include any transmission costs charged to KCPL by reason of Independence Power & Light becoming a member of SPP. KCPL has also requested that the Commission add to this amount an additional amount of $5 million, which it claims is an estimate of its increased transmission costs, subject to refund in a future rate case. Since this request was first submitted in surrebuttal testimony, it violates Commission Rule 4 CSR 240-2.130(7)(A), which requires that "[d]irect testimony shall include all testimony and exhibits asserting and explaining that party's entire case-in-chief." By submitting the request for the first time in surrebuttal, KCPL has prevented other parties from having a sufficient opportunity to conduct discovery or provide testimony on that matter. The Commission also finds that KCPL failed to adequately explain how it arrived at its estimate and how the Commission has the legal authority to grant such relief. For all these reasons, the Commission concludes that KCPL's request for an additional $5 million added to the approved base amount of revenue requirement should be denied.

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*Operations Company's Request for Auth. to Implement A Gen. Rate Increase for Elec. Serv.,* 2013 WL 299322 (Jan. 9, 2013).

### D. Property tax expense

**Findings of Fact**

122. KCPL requests that the Commission authorize a tracker mechanism for its expenses related to property taxes determined by Missouri state assessors. Those expenses would be deferred for consideration by the Commission to include in rates in KCPL's next rate case.[183]

123. A property tax tracker, as with other types of trackers, would create an inconsistent matching over time of investments, revenues and expenses.[184]

124. KCPL's property tax expenses have been increasing for the last five years, and may continue to increase in the future.[185]

125. Property taxes are normal operating costs that will continue to occur every year, and an annualized level of such expenses to include in rates can be reasonably calculated. KCPL's property taxes are not rare or unusual.[186]

126. KCPL's correct level of property tax expense to recognize in its revenue requirement on a total company basis is $91,616,599.[187]

127. In surrebuttal testimony, KCPL requested for the first time that for property tax expenses not afforded tracker treatment, $5.6 million of annual estimated Missouri jurisdiction property tax expense should be added to the revenue requirement above the base amount of Missouri jurisdiction property taxes. If the forecast amount recognized in revenue requirement exceeds actual property tax expenses during the period rates are in effect, such amounts should be credited to customers in a subsequent rate case.[188]

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[183] Ex. 134, Rush Direct, p. 28-29.
[184] Ex. 222, Lyons Rebuttal, p. 8.
[185] Ex. 124, Klote Direct, p. 75.
[186] Ex. 223, Lyons Surrebuttal, p. 23-24.
[187] Ex. 259, Revised True-Up Accounting Schedules, Income Statement Detail, p. 7.
[188] Ex. 136, Rush Surrebuttal, p. 16-17.

## Conclusions of Law and Decision

KCPL has requested that the Commission approval the same type of deferral mechanism for property tax expenses that it requested for transmission fee expenses. For that reason, the Commission incorporates herein the analysis contained in the conclusions of law and decision section from the transmission fee expense issue discussed above. The Commission concludes that KCPL has not met its burden of proof to demonstrate that projected property tax increases are extraordinary, so its request for a property tax tracker will be denied.

KCPL's correct level of property tax expense to recognize in its revenue requirement on a total company basis is $91,616,599. KCPL has also requested that the Commission add to this amount an additional amount of $5.6 million, which it claims is an estimate of its increased property tax costs, subject to refund in a future rate case. Since this request was first submitted in surrebuttal testimony, it violates Commission Rule 4 CSR 240-2.130(7)(A), which requires that "[d]irect testimony shall include all testimony and exhibits asserting and explaining that party's entire case-in-chief". By submitting the request for the first time in surrebuttal, KCPL has prevented other parties from having a sufficient opportunity to conduct discovery or provide testimony on that matter. The Commission also finds that KCPL failed to adequately explain how it arrived at its estimate and how the Commission has the legal authority to grant such relief. For all these reasons, the Commission concludes that the KCPL's request for an additional $5.6 million added to the approved base amount of revenue requirement should be denied.

## E. CIP/cyber-security expense

**Findings of Fact**

128. In 2007, the FERC designated the North American Regulatory Commission ("NERC") as the electric reliability organization under the Federal Power Act and subsequently approved NERC's reliability standards, which include the Critical Infrastructure Protection ("CIP") standards. CIP addresses the security of cyber assets essential to the reliable operation of the electric grid and is continuously evolving due to the fluid nature of security threats to critical infrastructure. CIP has recently been updated with Version 5, which includes new standards. KCPL is subject to these CIP standards.[189]

129. KCPL is requesting that the Commission authorize a tracker for the costs related to compliance with CIP and other cyber-security efforts. Those expenses would be deferred for consideration by the Commission to include in rates in KCPL's next rate case.[190]

130. A cyber-security tracker, as with other types of trackers, would create an inconsistent matching over time of investments, revenues and expenses.[191]

131. KCPL's CIP/cyber-security costs are projected to increase as a result of the addition of new employees and capital additions, primarily in 2015. Thereafter, those costs will decrease for the next two years.[192]

132. Compliance with CIP and cyber-security standards will be an ongoing cost for KCPL for the foreseeable future.[193]

[189] Ex. 118, Ives Direct, p. 27-28.
[190] Ex. 134, Rush Direct, p. 34.
[191] Ex. 222, Lyons Rebuttal, p. 28.
[192] Ex. 222, Lyons Rebuttal, p. 27.
[193] Transcript, Vol. 18, p. 1855.

133. KCPL's correct level of CIP/cyber-security expense to recognize in its revenue requirement on a Missouri jurisdictional basis are the highly confidential amounts stated in Ex. 256 HC, Lyons True-Up Rebuttal, p. 16, lines 1-2.

134. In surrebuttal testimony, KCPL requested for the first time that for CIP/cyber-security costs not afforded tracker treatment, $3.5 million of annual estimated Missouri jurisdiction CIP/cyber-security expense should be added to the revenue requirement above the base amount of Missouri jurisdiction CIP/cyber-security expense. If the forecast amount recognized in revenue requirement exceeds actual CIP/cyber-security expense during the period rates are in effect, such amounts should be credited to customers in a subsequent rate case.[194]

**Conclusions of Law and Decision**

KCPL has requested that the Commission approval the same type of deferral mechanism for CIP/cyber-security expenses that it requested for transmission fee expenses. For that reason, the Commission incorporates herein the analysis contained in the conclusions of law and decision section from the transmission fee expense issue discussed above. The Commission concludes that KCPL has not met its burden of proof to demonstrate that projected CIP/cyber-security increases are extraordinary, so its request for a tracker will be denied.

KCPL's correct annualized levels of transmission expense and revenue to recognize in its revenue requirement on a Missouri jurisdictional basis are the amounts stated in Ex. 256 HC, Lyons True-Up Rebuttal, p. 16, lines 1-2. KCPL has also requested that the Commission add to this amount an additional amount of $3.5 million, which it claims is an estimate of its increased CIP/cyber-security costs, subject to refund in a future rate case.

[194] Ex. 136, Rush Surrebuttal, p. 15-16.

Since this request was first submitted in surrebuttal testimony, it violates Commission Rule 4 CSR 240-2.130(7)(A), which requires that "[d]irect testimony shall include all testimony and exhibits asserting and explaining that party's entire case-in-chief". By submitting the request for the first time in surrebuttal, KCPL has prevented other parties from having a sufficient opportunity to conduct discovery or provide testimony on that matter. The Commission also finds that KCPL failed to adequately explain how it arrived at its estimate and how the Commission has the legal authority to grant such relief. For all these reasons, the Commission concludes that KCPL's request for an additional $3.5 million added to the approved base amount of revenue requirement should be denied.

### F. La Cygne environmental retrofit project

**Findings of Fact**

135. The La Cygne generating station is comprised of two coal-fired units, Unit 1 and Unit 2. KCPL owns 50% of La Cygne, and Kansas Gas and Electric Company, a wholly-owned subsidiary of Westar Energy, Inc., owns the other 50% share. Pursuant to the ownership agreement, KCPL is responsible for operating both La Cygne units.[195]

136. KCPL installed emission control equipment to reduce emissions from La Cygne by June 1, 2015, in order to comply with the Regional Haze Agreement that KCPL entered with the Kansas Department of Health and Environment. The emission control equipment is also required for compliance with the Mercury and Air Toxics Rule, the Cross-State Air Pollution Rule, and the National Ambient Air Quality Standards.[196]

137. The emissions control equipment that was installed at La Cygne included limestone-based, wet scrubber flue gas desulfurization systems, fabric filters, mercury

[195] Ex. 102, Bell Direct, p. 7.
[196] Ex. 127, Ling Direct, p. 2-3.

control systems on both Units 1 and 2, and low $NO_x$ burners, over-fired air, and selective catalytic reduction system on Unit 2.[197]

138. KCPL successfully achieved the in-service criteria for La Cygne. As of March 24, 2015, Unit 2 was in-service, and as of April 30, 2015, Unit 1 was in-service.[198]

139. The projected cost of the entire retrofit project was $1.23 billion. While the final project costs are not yet determined, there is an indication that the project will be completed at some level below the estimated cost. Commission's Staff conducted a construction audit and prudence review of the project, and concluded that no adjustments should be proposed regarding the costs KCPL is requesting to be included in rates in this case. Staff determined that the prudently incurred costs to include in KCPL's Missouri rate base for the La Cygne project were $292,620,121.[199]

140. Before making the decision to proceed with the La Cygne environmental retrofit project, in 2010 KCPL conducted a multi-faceted analysis of a series of alternative long-term resource plans to assess the risk associated with various critical factors, such as natural gas prices, retail customer load growth, and carbon dioxide costs. The end result of this process resulted in an expected 25-year net present value of revenue requirement ("NPVRR") that evaluates the risks associated with uncertain factors in the electric utility industry.[200]

141. The results of this analysis completed in early 2011 demonstrated that the most cost-effective solution was the retrofitting of La Cygne Units 1 and 2.[201] KCPL's decision to retrofit La Cygne was supported by its determination that retiring the La Cygne

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[197] Ex. 102, Bell Direct, p. 9.
[198] Ex. 162, Bell True-Up Direct, p. 1-2.
[199] Ex. 252, Hyneman True-Up Direct, p. 5-21.
[200] Ex. 109, Crawford Direct, p. 17, 20.
[201] Ex. 109, Crawford Direct, p. 24-25; Transcript, Vol. 12, p. 792-93.

units and replacing them with combined-cycle natural gas generation would have resulted in a significant reliance on the relatively more volatile natural gas market.[202]

142. KCPL submitted its analysis of whether to retire or retrofit La Cygne to the Kansas Corporation Commission on February 23, 2011, as part of a petition for predetermination, which sought authorization to recover expenditures on the La Cygne retrofits.[203] The Kansas commission granted KCPL's petition on August 19, 2011.[204]

143. Sierra Club's witness Rachel Wilson alleges that KCPL was imprudent in 1) failing to consider missing elements in its calculations that would have raised the costs to retrofit La Cygne, and 2) deciding to continue with the retrofit project in 2011 and 2012. She argues that while natural gas prices were declining during this period of time, KCPL should have re-evaluated its analysis using 2011 and 2012 forecasts from the Energy Information Administration's Annual Energy Outlook ("AEO"). Wilson alleges that using this AEO forecast would have revealed that retirement of La Cygne units would have been the more economic choice.[205]

144. KCPL did not fail to consider a reasonable level of cost-effective energy efficiency or a full range of options for addressing regulations such as non-gas supply options. The net benefits in KCPL's original analysis significantly exceeded other alternative plans considered. KCPL did not consider the conversion from a wet to a dry bottom ash system for Unit 2, but the projected costs would not have meaningfully changed the results.[206]

[202] Ex. 109, Crawford Direct, p. 22-24; Ex 110, Crawford Rebuttal, p. 2.
[203] Ex. 402, Wilson Direct, p. 6.
[204] *Id.* at p. 27.
[205] Ex. 402, Wilson Direct, p. 3-5.
[206] Ex. 110, Crawford Rebuttal, p. 3-5.

145. In KCPL's original analysis, it utilized several long-term forecasts regarding gas prices, which produces better results over time than using a single forecast.[207] KCPL did not use the single AEO forecast alone because that forecast does not take into account future regulations that can produce upward pressure on gas prices.[208]

146. KCPL re-evaluated whether it was appropriate to retrofit the La Cygne units on four occasions, once each in 2012, 2013, 2014 and 2015, as part of KCPL's integrated resource planning ("IRP") process. The 2012 IRP planning work started in the summer of 2011, included the 2012 AEO forecast, and assumed that no project costs had been committed.[209]

147. Witness Burton Crawford testified credibly that the results of each re-evaluation of the La Cygne analysis during the IRP processes demonstrated that continuing with the retrofit project resulted in lower overall costs than resource plans that included retiring those units.[210]

## Conclusions of Law and Decision

In rate cases, there is initially a presumption that a utility's expenditures incurred in providing utility service, which are one component of its revenue requirement, are prudent.[211] This presumption can be rebutted upon a showing of serious doubt as to the prudence of the expenditure, at which point the utility must dispel this doubt and prove the questioned expenditure is prudent.[212] The Commission has interpreted this process as follows:

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[207] *Id.* at p. 6.
[208] *Id.* at p.9-10.
[209] *Id.* at p. 7; Transcript, Vol. 12, p. 783-84.
[210] *Id;* Transcript, Vol. 12, p. 777.
[211] *State ex rel. Public Counsel v. Public Service Comm'n*, 274 S.W.3d 569, 586 (Mo. App. 2009).
[212] *Id*.; *State ex rel. Associated Natural Gas Company v. Public Service Commission of the State of Missouri,* 954 S.W.2d 520, 528 (Mo.App.1997); *In the Matter of Union Electric Company*, 27 Mo.P.S.C. (N.S.) 183, 193

> In the context of a rate case, the parties challenging the conduct, decision, transaction, or expenditures of a utility have the initial burden of showing inefficiency or improvidence, thereby defeating the presumption of prudence accorded the utility. The utility then has the burden of showing that the challenged items were indeed prudent. Prudence is measured by the standard of reasonable care requiring due diligence, based on the circumstances that existed at the time the challenged item occurred, including what the utility's management knew or should have known. In making this analysis, the Commission is mindful that "[t]he company has a lawful right to manage its own affairs and conduct its business in any way it may choose, provided that in so doing it does not injuriously affect the public.[213]

Testimony on behalf of Sierra Club from Ms. Wilson raised a serious doubt about KCPL's decision to proceed with the La Cygne retrofit project following authorization of the project by the Kansas Corporation Commission. Natural gas prices did fall shortly after KCPL completed its original analysis showing that the retrofit project was a lower-cost option than retirement of the units, and that original analysis did not take into account an AEO forecast showing those lower gas prices. Ms. Wilson alleges that KCPL waited too long to re-evaluate its original decision, and if it had done so it would have found that retirement was actually the lower-cost option after considering the lower gas prices.

KCPL's witnesses testified credibly, however, that the 2012 re-evaluation process was started just a few months after the release of the 2012 AEO forecast, that they included that forecast, in addition to several other more reliable forecasts, in their planning process, and that the result of the 2012 IRP process yielded the same result as the original KCPL analysis that was approved in Kansas. When the retrofit project was re-evaluated each year in 2012-2015, those studies showed that the retrofit project resulted in lower overall costs than resource plans that included retiring those units. In addition, the evidence

(1985) (*quoting Anaheim, Riverside, etc. v. Federal Energy Regulatory Commission*, 669 F.2d 779, (D.C. Cir. 1981)).

[213] *State ex rel. City of St. Joseph v. Public Service Commission*, 30 S.W.2d 8, 14 (Mo. banc 1930); In the Matter of Missouri-American Water Company's Tariff Sheets, *Report and Order*, Case No. WR-2000-281 (August 31, 2000), 9 Mo. P.S.C. 3d 254.

shows that KCPL did not fail to consider missing elements in its calculations that would have raised the costs to retrofit La Cygne.

The Commission concludes that KCPL has met its burden of proof to demonstrate that, based on the circumstances that existed at the time, KCPL was prudent in choosing to proceed with the La Cygne environmental retrofit project. The correct and prudently incurred costs to include in KCPL's Missouri rate base for the La Cygne project are $292,620,121.

## G. Rate case expense

### Findings of Fact

148. Rate case expense can be defined as all incremental costs incurred by a utility directly related to an application to change its general rate levels.[214]

149. KCPL's total rate case expense as of August 12, 2015, is $1,024,304.[215]

150. Rate case expense can benefit both utility shareholders and customers, though often in different ways. A utility and its shareholders directly benefit from this expense because generally these costs are incurred in order to increase a utility's revenues and, ultimately, its profitability. Customers benefit generally from being served by financially healthy utilities, which is bolstered in part by the ability of a utility to periodically seek increased rates to recover increasing expenses and earn a return on investments in their systems.[216]

151. The rate case process can be adversarial in nature, with the utility and ratepayers on opposing sides.[217]

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[214] Ex. 243, p. 1.
[215] Ex. 169 and 216. OPC's rate case expense amount in Ex. 319 differed from that of both KCPL and Staff, and so is found to be less credible.
[216] Ex. 243, p. 11.
[217] Transcript, Vol. 13, p. 1022.

152. KCPL engaged several outside experts and consultants in this case. Witness Spanos performed the depreciation study required by Commission rules. Mr. Hevert performed a cost of capital/capital structure analysis using industry-wide data. Witness Rogers did a highly-specialized study to determine the cost of dismantling non-nuclear generating units. Mr. Overcast testified on the topic of regulatory mechanisms. These types of testimonies and studies are generally performed by outside experts in rate cases in Missouri.[218]

153. Staff and OPC propose that the expenses of KCPL witness Overcast be disallowed as duplicative of testimony given by other witnesses.[219]

154. KCPL retained the services of witness Overcast to respond to other parties opposed to KCPL's requests for a fuel adjustment clause and trackers. Mr. Overcast was hired to provide a nationwide view of how other jurisdictions have approached such alternative regulatory mechanisms.[220]

155. KCPL was represented in this case by both in-house and external legal counsel. KCPL used two in-house attorneys and employed two outside attorneys. The two outside attorneys have represented KCPL in numerous rate cases and other Commission proceedings in the past to supplement the in-house legal team.[221]

156. OPC witness Addo proposed adjustments to rate case expenses, including reducing the hourly rates of KCPL outside attorneys to $200/hour, based on the rates one attorney charged Ameren Missouri and the results of a 2013 survey of hourly rates by the Missouri Bar.[222]

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[218] Ex. 120, Ives Rebuttal, p. 25.
[219] Ex. 226, Majors Surrebuttal, p. 62-63; Ex. 308, Addo Surrebuttal, p. 27-28.
[220] Transcript, Vol. 13, p. 970-71.
[221] Ex. 120, Ives Rebuttal, p. 26.
[222] Ex. 308, Addo Surrebuttal, p. 26-30.

157. Mr. Addo did not compare the background and experience of the KCPL attorneys with that of the Ameren Missouri attorney, and he did not calculate the number of hours or examine the tasks that Ameren Missouri's counsel performed on a prior rate case.[223]

158. In Missouri, almost all utilities hire witnesses to sponsor their rate of return/return on equity positions in rate cases and often hire consultants to handle other issues, as well.[224]

159. In a rate case, a utility chooses how many and what type of consultants it will engage, what issues to pursue, and what legal strategies it will employ, and therefore, the extent of rate case expense is largely at KCPL's discretion.[225]

160. The expenses in this case are driven primarily by issues raised by KCPL, which has complete control over the content and methodologies proposed in its rate cases. For example, KCPL has requested several trackers, two of which have never been requested before in Missouri and two of which were first presented in rebuttal testimony[226], and has requested recovery in rates of the expenses from the Clean Charge Network.

161. KCPL has requested that all costs and expenses associated with legal representation, consultants, and expert witnesses be included in its increased revenue requirement.[227]

162. All consumer groups were represented by hired counsel in this case, and some also engaged expert witnesses. While KCPL is able to recoup the costs of its legal counsel and expenses through utility service rates, OPC, the entity representing

[223] Transcript, Vol. 13, p. 1068-72.
[224] Ex. 243, p. 1-2.
[225] Transcript, Vol. 13, p. 1062; Ex. 226, Majors Surrebuttal, p. 57-58.
[226] Ex. 226, Majors Surrebuttal, p. 60-61.
[227] Ex. 169HC; Ex. 261HC.

ratepayers, operates within a tight annual budget, and interveners pay their own legal expenses.[228]

163. Prudency reviews, by their nature, are not a strong incentive to control costs. The utility holds all the information a challenging party needs to prove imprudence, and it is not likely a challenging party could identify all instances of imprudence, even when engaged in a conscientious prudence review.[229]

164. Awarding a utility all of its incurred rate case expenses could provide that utility with a significant financial advantage over other participants in the rate case process, who may be constrained by budgetary and other financial restrictions. Such a practice does not encourage reasonable levels of cost containment in the utility's rate case expense decisions.[230]

165. An incentive for a utility to limit its rate case expense is to tie a utility's percentage recovery of rate case expense to the percentage of its rate increase request that the Commission finds just and reasonable. Use of this approach would directly tie a utility's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in a rate case.[231]

166. KCPL previously filed rate cases in 2006, 2007, 2009, 2010, and 2012.[232] In recent rate cases, KCPL has incurred rate case expenses substantially higher than historical levels and higher than other utilities in Missouri.[233]

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[228] Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 132-33.
[229] Transcript, Vol. 18, p. 1745-46; Transcript, Vol. 16, p. 1520-21.
[230] Ex. 243, p. 11-12.
[231] *Id.* at p. 14; Ex. 236, Oligschlaeger Surrebuttal, p. 9-11; Transcript, Vol. 13, p. 1056-58.
[232] Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 3-4.
[233] Transcript, Vol. 13, p. 1063; Ex. 243, p. 6-8.

167. Prudence is not the only consideration in determining what costs should be included in rates; the benefit to customers must also be considered when deciding what costs are reasonable for customer rates.[234]

168. KCPL has pursued issues in this case that benefit only the shareholders, such as La Cygne construction accounting and some elements of the rate of return recommendation.[235] Utility expenses that are highly discretionary and do not benefit customers, such as charitable donations, political lobbying expenses, and incentive compensation tied to earnings per share, are typically allocated entirely to shareholders.[236]

169. Staff and OPC recommend that the Commission require shareholders and ratepayers to share the rate case expense costs equally.[237] Staff also proposes, as an alternative to equal sharing of expenses, that KCPL receive rate recovery of rate case expenses in proportion to the amount of rate relief it is granted compared to the amount of its original rate increase request.[238]

**Conclusion of Law and Decision**

In a rate case, the Commission has broad discretion to determine which expenses a utility may recover from ratepayers. The Missouri Supreme Court has stated that the Commission's statutory power and authority to set rates "necessarily includes the power and authority to determine what items are properly includable in a utility's operating expenses and to determine and decide what treatment should be accorded such expense

[234] Transcript, Vol. 13, p. 1050.
[235] Transcript, Vol. 13, p. 1033-34.
[236] Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 133-34; Ex. 226, Majors Surrebuttal, p. 57-58.
[237] Ex. 226, Majors Surrebuttal, p. 55; Ex. 307, Addo Rebuttal, p. 46.
[238] Ex. 236, Oligschlaeger Surrebuttal, p. 10-11.

items."[239] The Commission's authority extends to allocating an expense between certain classes or groups of ratepayers[240] and to requiring company shareholders to bear expenses the Commission finds to be unreasonable or unnecessary.[241]

As stated above, there is initially a presumption that a utility's expenditures incurred in providing utility service, which are one component of its revenue requirement, are prudent.[242] This presumption can be rebutted upon a showing of serious doubt as to the prudence of the expenditure, at which point the utility must dispel this doubt and prove the questioned expenditure is prudent.[243]

Staff and OPC allege that the expenses of witness Overcast should be disallowed because his testimony was duplicative and those expenses were imprudent. Similarly, OPC and MECG argue that the fees of KCPL's outside attorneys were imprudent and should be reduced to $200/hour or disallowed entirely. These expenses for experts, consultants, and attorneys do not lend themselves to review for prudence. Unlike industry standards for pipe size or transmission line capacity, there is no accessible appropriate standard for determining whether one consultant's analysis was truly unnecessary or if one attorney's expertise is worth more than another's. The evidence does not reveal a bright line solution to this problem, and the Commission will not disallow these or any other rate case expenses in this case.

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[239] *State ex rel. City of W. Plains v. Pub. Serv. Comm'n*, 310 S.W.2d 925, 928 (Mo. 1958). See also, *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d 153, 166 (Mo. App. 2013).
[240] *State ex rel. City of W. Plains v. Pub. Serv. Comm'n*, 310 S.W.2d at 934.
[241] *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d at 164-165.
[242] *State ex rel. Public Counsel v. Public Service Comm'n*, 274 S.W.3d 569, 586 (Mo. App. 2009).
[243] *Id*.; *State ex rel. Associated Natural Gas Company v. Public Service Commission of the State of Missouri,* 954 S.W.2d 520, 528 (Mo.App.1997); *In the Matter of Union Electric Company*, 27 Mo.P.S.C. (N.S.) 183, 193 (1985) (*quoting Anaheim, Riverside, etc. v. Federal Energy Regulatory Commission*, 669 F.2d 779, (D.C. Cir. 1981)).

Instead, the Commission will consider whether it is reasonable that KCPL shareholders cover a portion of KCPL's rate case expense. In one sense, rate case expense is like other common operational expenses that a utility must incur to provide utility services to customers. Since customers benefit from having just and reasonable rates, it is appropriate for customers to bear some portion of the utility's cost of prosecuting a rate case.

However, rate case expense is also different from most other types of utility operational expenses, in that 1) the rate case process is adversarial in nature, with the utility on one side and its customers on the other; 2) rate case expense produces some direct benefits to shareholders that are not shared with customers, such as seeking a higher return on equity; 3) requiring all rate case expense to be paid by ratepayers provides the utility with an inequitable financial advantage over other case participants; and 4) full reimbursement of all rate case expense does nothing to encourage reasonable levels of cost containment.

The Commission has the legal authority to apportion rate case expense between ratepayers and shareholders. Under Missouri law, the Commission must set just and reasonable rates[244], and rates that include all of the utility's rate case expense, for the reasons set forth above, may not be just or reasonable.[245] Moreover, this Commission has already found rate case expense sharing to be just and reasonable in at least one prior case. In a 1986 decision, *In the Matter of Arkansas Power and Light Company*, the Commission "adopted Public Counsel's proposed disallowance of one-half of rate case

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[244] Section 393.130.1, RSMo, "…All charges made or demanded by any…electrical corporation … shall be just and reasonable and not more than allowed by law or by order or decision of the commission…"
[245] There are rate cases where the utility does not have the means to absorb a portion of rate case expense and requiring it to do so would ultimately harm customers. In such circumstances, it would appear just and reasonable that rates include the entire amount of rate case expense.

expense."[246] It is also important to note that there are a number of other cases where the Commission acknowledged it has this authority.[247]

KCPL argues that it would be unlawful for the Commission to adopt a new policy related to the recovery of rate case expense without conducting a rulemaking proceeding under Chapter 536, RSMo. The Commission agrees that it cannot prospectively change its statement of general applicability that implements, interprets or prescribes law or policy, or that describes the organization, procedure, or practice requirements before this agency.[248] Agencies cannot engage in this type of rulemaking by an adjudicated order.[249] However, the Commission is not announcing a general change in policy regarding rate case expense for all utilities in this Report and Order. Rather, the Commission is setting just and reasonable rates under the particular facts of this case, so the Commission is not engaging in improper rulemaking.

The evidence shows that the expenses in this case are driven primarily by issues raised by KCPL, which has complete control over the content and methodologies proposed when it files its rate cases. In this case, KCPL has requested three new trackers, two of which have never been requested before in Missouri. KCPL has also requested recovery in rates of the expenses from the Clean Charge Network, which is a type of expense that has never been raised in a rate case before this Commission. Each of these issues are unique to KCPL, and while KCPL always has the opportunity to pursue new and unique issues in a

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[246] Report and Order, File No. ER-85-265, 28 Mo. P.S.C. (N.S.) 435, 447 (1986),
[247] See, *In the Matter of Kansas City Power & Light Company,* Report and Order, File Nos. EO-85-185 and EO-85-224, 28 Mo. P.S.C. (N.S.) 229, 263 (1986), and *in the Matter of Missouri Gas Energy,* Report and Order, File No. GR-2009-0355, 19 Mo. P.S.C. 3d 245, 303 (2010).
[248] Section 536.010(6) defines a rule as "each agency statement of general applicability that implements, interprets, or prescribes law or policy." In other words, a rule is "[a]n agency statement of policy or interpretation of law of future effect which acts on unnamed and unspecified persons or facts." *Missourians for Separation of Church and State v. Robertson,* 592 S.W.2d 825, 841 (Mo.App.1979). *HTH Companies, Inc. v. Missouri Dept. of Labor and Indus. Relations*, 157 S.W.3d 224, 228 -229 (Mo. App. 2004); *Greenbriar Hills Country Club v. Director of Revenue*, 47 S.W.3d 346, 357 (Mo. banc 2001).
[249] Greenbriar Hills Country Club v. Director of Revenue, 47 S.W.3d 346, 357 (Mo. banc 2001).

rate case, the decision to do so is entirely with KCPL's power. In addition, KCPL has pursued some issues that only directly benefit shareholders, such as the La Cygne accounting authority and, of course, a higher ROE. In recent rate cases, KCPL has incurred rate case expenses substantially higher than historical levels and higher than other utilities in Missouri.

The Commission finds that in order to set just and reasonable rates under the facts in this case, the Commission will require KCPL shareholders to cover a portion of KCPL's rate case expense. One method to encourage KCPL to limit its rate case expenditures would be to link KCPL's percentage recovery of rate case expense to the percentage of its rate increase request the Commission finds just and reasonable.[250] The Commission determines that this approach would directly link KCPL's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in this rate case.[251]

The Commission concludes that KCPL should receive rate recovery of its rate case expenses in proportion to the amount of revenue requirement it is granted as a result of this Report and Order, compared to the amount of its revenue requirement rate increase originally requested. This amount should be normalized over three years. The Commission also finds that it is appropriate to require a full allocation to ratepayers of the expenses for KCPL's depreciation study, recovered over five years, because this study is required under Commission rules to be conducted every five years.

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[250] This method can be expressed as: (Revenue Requirement Approved / Original Revenue Requirement Requested) X 100 = allowable percentage of rate case expense.

[251] 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 also 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.

## H. Management audit

**Findings of Fact**

170. KCPL's Administrative & General ("A&G") costs from 2011 through 2013 were higher than three other utilities operating in this region. While the reasons for this are unknown, it may be due to a structural problem.[252]

171. Staff's analysis of KCPL's A&G expenses, which examined the peer group utilities that KCPL used to determine executive compensation, credibly demonstrated that KCPL has some of the highest A&G expenses of its national peers and Missouri utilities. Of the group examined, KCPL has the highest A&G costs per customer, per dollar of revenue, and compared to its operations and maintenance expense, and the third highest A&G expense per megawatt hour of electricity sold. [253]

172. A management audit focused on identifying and achieving efficiencies and cost reductions should benefit both KCPL's customers and shareholders.[254]

**Conclusions of Law and Decision**

MECG and MIEC witness Kollen has recommended that the Commission direct KCPL to undergo a management audit by an independent auditor to identify cost savings and efficiencies. The evidence showed that KCPL's A&G expenses are significantly higher than its peers, but that the cause for this discrepancy is unknown. The Commission finds that it would benefit both customers and shareholders to find efficiencies and reduce costs, so a management audit is a reasonable mechanism to accomplish this result. However, rather than charge the costs of such an audit to KCPL's customers or shareholders, such an audit could be performed by the Commission's Staff. The Commission will initiate a

[252] Ex. 500, Kollen Direct, p. 8-15.
[253] Ex. 226, Majors Surrebuttal, p. 40-54.
[254] Ex. 501, Kollen Surrebuttal, p. 12.

separate case after this case is concluded that directs the Commission's Staff[255] to audit KCPL's A&G expenses.

## I. Clean Charge Network

### Findings of Fact

173. On January 26, 2015, KCPL publicly announced that it had launched a joint initiative ("Clean Charge Network") with KCP&L Greater Operations Company to install and operate more than 1,000 electric vehicle charging stations throughout the greater Kansas City region. The charging stations would be capable of supporting more than 10,000 electric vehicles and upon completion would be the largest such utility-owned installation in the United States.[256]

174. During a two-year pilot period, the Clean Charge Network would offer free charging on every station to all electric vehicle drivers. Any electricity costs for charging station usage would be paid by partnering organizations during the pilot period.[257]

175. KCPL has initiated the Clean Charge Network to promote environmental sustainability, reduce carbon emissions, and help the Kansas City region attain EPA regional ozone standards.[258]

176. KCPL has requested that the charging stations placed in service in its Missouri service territory as of May 31, 2015, be included in rate base as a part of the revenue requirement for this case.[259] As of that date, KCPL has invested $732,559 in its Clean Charge Network in Missouri, but plans to invest a total of $7-8 million.[260]

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[255] The Commission's Staff includes a unit that specializes in management services and that has conducted management audits of varying scope in the past at the Commission's discretion.
[256] Ex. 119, Ives Supplemental Direct, p. 1-2.
[257] *Id.* at p. 2.
[258] *Id.* at p. 3.
[259] *Id.* at p. 5.
[260] Transcript, Vol. 11, p. 567, 600.

177. KCPL developed the Clean Charge Network project without soliciting input from any of the parties to this case, including those parties representing customers who would bear the costs of the project if the Commission includes those costs in KCPL's revenue requirement.[261]

178. KCPL has not established any criteria by which it proposes to measure the success of the Clean Charge Network, and has not conducted studies concerning the five areas of alleged public benefit – beneficial electrification, environmental benefits, economic development, customer programs, and cost and efficiency benefits.[262]

179. Important program details relating to ratepayer subsidies, program goals, income distribution, public participation, tariffs, program design, scope of the investment, risk shifting, cost-benefit analysis, participating organizations, host sites, free electricity offerings, anti-competitive subsidies, and proper performance-based measures to determine effectiveness are all missing from KCPL's proposal and would be best addressed in a separate working case.[263]

180. A KCPL witness agreed that a working case would be a good place to address long-term policy issues relating to the Clean Charge Network, including potential impacts on both customers and the company.[264]

**<u>Conclusions of Law and Decision</u>**

KCPL's proposed Clean Charge Network is an important first step in creating an infrastructure to serve the increasing number of customers who choose to purchase electric vehicles, and the Commission commends KCPL for its efforts to anticipate this future demand and for its commitment to environmental sustainability. However, this issue was

[261] *Id.* at p. 626-27.
[262] *Id.* at p. 577-83.
[263] Ex. 304, Dismukes Rebuttal, p. 11-39.
[264] Transcript, Vol. 11, p. 577.

raised for the first time more than three months after KCPL first filed this case and without seeking input from this Commission or other parties to the case. The proposal currently lacks important information that is critical to designing and implementing a program unlike any other existing in the state. While the Commission believes that it would be beneficial to move forward with the Clean Charge Network, it is premature to require KCPL's customers to bear the costs of the program. The Commission concludes that KCPL has failed to meet its burden of proof to demonstrate that the charging stations placed in service in its Missouri service territory as of May 31, 2015, should be included in rate base as a part of the revenue requirement for this case, so that request will be denied. The Commission will establish a working case in order to address the legal and long-term policy issues relating to the Clean Charge Network.

### J. Income tax issues

**<u>CWIP-related ADIT</u>**

**<u>Findings of Fact</u>**

181. Accumulated deferred income taxes ("ADIT") are assets or liabilities that represent the cumulative amounts of additional income taxes that are estimated to become receivable or payable in future periods. Future income taxes are impacted by tax returns filed today because of differences between book accounting and income tax accounting regarding the timing of revenue or expense recognition.[265]

182. Specific provisions within GAAP require recognition of income tax impacts from these book/tax timing differences, by recording ADIT assets or liabilities. ADIT assets generally occur when revenue taxation occurs prior to book recognition of the revenues or when the tax deductibility for expenses is subsequent to the book recognition of the

[265] Ex. 502, Brosch Direct-Revenue Requirement, p. 46.

expense. ADIT liabilities, on the other hand, represent delayed taxation of revenues or advance deduction of expenses, in relation to the timing of the same transactions on the books. ADIT balances exist to recognize that certain tax expenses are determinable today, but actually become payable in the future whenever book/tax timing differences ultimately reverse.[266]

183. From a ratemaking perspective, a utility's persistently large credit ADIT balances caused by the deferred payment of recorded tax expenses represent a significant source of capital to the utility. ADIT balances represent a form of zero-cost capital to the utility created by the income tax savings permitted under tax laws and regulations that are not immediately "flowed through" to ratepayers and would benefit only shareholders unless properly recognized as a rate base reduction. ADIT balances are normally included in rate base as reductions by regulators, so as to limit the utility to only a return on the net amount of investor-supplied capital to support rate base assets.[267]

184. KCPL records ADIT that is associated with Construction Work in Progress ("CWIP") reflected on its books and records. This ADIT represents a free source of capital funds available for use by the utility before the construction project is completed and included in plant-in-service. CWIP is excluded from the rate base on which KCPL earns a return in the ratemaking process. Although CWIP is not included in rate base, KCPL is allowed to earn an Allowance for Funds Used During Construction ("AFUDC") before the property under construction is added to rate base. AFUDC is accrued during the construction of the asset and included in rate base when the plant is placed into service. The amount of AFUDC is included in depreciation and rate base over the life of the plant. For the calculation of AFUDC, there is no consideration for ADIT as a reduction to the base

[266] *Id.* at p. 47.
[267] *Id.* at p. 48.

on which it is calculated; the AFUDC is calculated on the "gross" amount, with no consideration of ADIT.[268]

185. Because ADIT is not considered in the calculation of AFUDC, the benefit must be accounted for by an offset to rate base for ADIT associated with CWIP balances.[269]

186. KCPL ratepayers provide fully-normalized income taxes in the cost of service regardless of the actual amount paid to the IRS. Even if KCPL is not realizing all the benefits of accelerated depreciation due to a net operating loss position, it does not invalidate the fact that ratepayers are providing several million dollars in cash income taxes.[270]

## Conclusions of Law and Decision

KCPL excluded the ADIT liability related to CWIP since the capital expenditures have not been included in rate base. KCPL argues that since CWIP cannot be included in rates in Missouri, KCPL's shareholders, not its customers, are paying the costs associated with plant under construction. KCPL states that it is unfair to include the ADIT offset to rate base when the CWIP itself may not be included.

The Commission considered this issue recently in another rate case. In reaching the conclusion that it is appropriate to reduce rate base for CWIP-related ADIT balances, that Commission stated that:

> CWIP related ADIT balances must be accounted for in rate base because AFUDC is applied to Ameren Missouri's gross investment in CWIP, with no recognition given to the CWIP-related ADIT amounts that serve to reduce the company's actual net capital requirements for CWIP… In other words, failure to recognize the CWIP-related ADIT balance in the company's rate base will overstate the companies AFUDC costs and future rate base, essentially

[268] Ex. 200, Staff Report-Revenue Requirement Cost of Service, p. 178.
[269] Ex. 226, Majors Surrebuttal, p. 64.
[270] Ex. 226, Majors Surrebuttal, p. 64-65.

allowing the company to earn AFUDC and a return on capital supplied by ratepayers.[271]

KCPL asserts that its situation is different than that of the utility at issue in File No. ER-2012-0166 because KCPL has a net operating loss and, as a consequence, KCPL has more deductions than it has revenues during the applicable period, so it has not and will not receive a cash tax benefit. However, KCPL ratepayers provide fully-normalized income taxes in cost of service regardless of whether KCPL pays those taxes concurrently to the IRS. Even if KCPL is not realizing all the benefits of accelerated depreciation due to a net operating loss position, it does not invalidate the fact that ratepayers are providing several million dollars in cash income taxes. The Commission concludes that the amount of ADIT related to CWIP should be an additional reduction to KCPL's rate base.

**1KC Place lease ADIT**

**Findings of Fact**

187. KCPL occupies leased office space in downtown Kansas City in a building known as 1 KC Place and has received certain lease abatement benefits in connection with its lease agreement. On its books, KCPL has recorded a significant liability balance to recognize the delayed obligation to make additional lease payments. In connection with this liability balance, a large and offsetting deferred tax asset was recorded to recognize that accrued but unpaid future lease costs are not currently deductible for income tax purposes. KCPL proposes to include in rate base the debit ADIT item to increase rate base, but not the corresponding accrued lease liability balance that would reduce rate base if recognized.[272]

[271] Report and Order, *In the Matter of Union Elec. Co., d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Elec. Serv.*, ER-2012-0166, 2012 WL 6643105 (Dec. 12, 2012).
[272] Ex. 502, Brosch Direct-Revenue Requirement, p. 55.

188. The accrued liability for the deferred rent payments on the 1KC Place lease has not been included in rate base, but this accrued liability is being amortized as a reduction to rent expense.[273]

189. This reduced rent expense is included in the cash voucher line within the expense lead day calculations of KCP&L's lead lag study. Although there has not been a separate lead lag computation on the 1KC Lease directly, the reduction in rent expense is included in the overall cash working capital computations and in the rent expense included in cost of service.[274]

## **Conclusions of Law and Decision**

A proposed adjustment concerns the ADIT asset related to the 1KC Place lease. This ADIT increases rate base, unlike the ADIT related to CWIP. Because the deduction for the 1KC Place lease has not been taken on a tax return, but has been taken for financial and regulatory purposes, the ADIT asset represents tax benefits that the ratepayers have received in computing income tax expense but that KCPL has not received on its tax returns.

KCPL has not included the accrued liability for the deferred rent payments on the 1KC Place lease in rate base. This exclusion is appropriate because the accrued liability is being amortized monthly as a reduction to rent expense in cost of service. This reduced rent expense is also included in KCPL's lead lag computation of cash working capital. The Commission concludes that the impact of this liability has been included in the case, and the ADIT asset related to this liability should be included in rate base, so no adjustment should be made.

[273] Ex. 112, Hardesty Rebuttal, p. 6.
[274] *Id.* at p. 6-7.

## Employee compensation ADIT

### Findings of Fact

190. Certain elements of employee compensation are paid much later than they are earned, requiring the Company to recognize an accrued liability for such deferred compensation and bonus pay that is owed to its employees.[275]

191. The accrued liability for the employee compensation and bonus pay has not been included in rate base.[276]

192. This accrued liability is for two different items. One item is the ADIT asset for the deferred compensation, where certain executives have elected to defer the payout of a portion of their salary and incentive compensation to a future period. The second item is the ADIT asset for the incentive compensation (bonus pay) that is accrued during the year, but is not paid out in cash until March 15 of the following year. For both of these items, the salary and incentive compensation is included in cost of service expense and in the total payroll or cash voucher line on the lead day calculations of KCP&L's lead lag study. Although there has not been a separate lead lag computation on these liabilities directly, the salary and incentive compensation is included in the overall cash working capital computations and in the payroll expense included in cost of service.[277]

### Conclusions of Law and Decision

The proposed adjustment to exclude the ADIT asset related to employee compensation and bonus pay from rate base would also decrease the revenue requirement. The proposed adjustment, which is similar to the proposal for the 1KC Place lease, is based on an argument that the liability for the accrued employee compensation

[275] Ex. 502, Brosch Direct-Revenue Requirement, p. 56.
[276] Ex. 112, Hardesty Rebuttal, p. 7.
[277] *Id.* at p. 6-7.

and bonus pay is not in rate base so the ADIT asset related to this tax timing difference should also be excluded. However, both deferred compensation and bonus pay are included in the overall cash working capital computations, and the payroll expense is included in cost of service. Therefore, since the impact of this liability has been included in this case, the Commission concludes that the ADIT asset related to this liability should be included in rate base and no adjustment should be made.

**Net operating tax losses**

**Findings of Fact**

193. KCPL files its taxes as part of a consolidated group, consisting of GPE and its affiliated companies. Consolidated filing benefits the entire group, but it is the nature of a consolidated filing that any given member may be better off in some years and worse off in other years as a result of consolidated filing.[278]

194. A net operating loss ("NOL") is created when, in any year, a taxpayer reports more deductions than it has taxable income. Under the generally applicable tax rules, an NOL can be carried back two years or forward 20 years. In the year in which it is carried to, an NOL is treated like an additional deduction, reducing the taxable income otherwise produced in that year. When an NOL must be carried forward, a portion of the deductions claimed by the taxpayer in the year that the NOL is created will not offset taxable income and not reduce the taxpayer's tax liability – thus, no cost-free capital was received for the amount of NOL that did not reduce the tax liability.[279]

195. In KCPL's rate case application, it reflected the impact of its NOL carryforward for tax purposes as an ADIT asset (a deferred tax asset) of approximately $37.8 million.

[278] Ex. 112, Hardesty Rebuttal, p. 9, 16.
[279] *Id.* at p. 11-12.

This had the effect of increasing rate base by that amount (by decreasing the overall ADIT balance which reduces rate base).[280]

196. KCPL reduces its rate base by its net ADIT liability balance (sum of deferred tax assets and deferred tax liabilities) as a result of timing differences between deductions for tax purposes and financial statement purposes. The net deferred tax liability is used to reduce rate base because it represents a source of cost-free capital (a reduction in the amount of cash paid for tax purposes) that KCPL has received as a consequence of claiming certain tax deductions. In a year that KCPL generates a net operating loss for tax purposes that is carried forward, the NOL carryforward reduces the amount of cost-free capital it received. Therefore, KCPL has reflected in its rate base computation the actual impact its NOL has had on the amount of cost-free capital it received using the method prescribed under the Internal Revenue Service regulations to allocate losses to companies within a consolidated group.[281]

197. KCPL computes the amount of NOLs allocated to each subsidiary based on when and how the NOLs are used by the consolidated group in accordance with the Tax Allocation Agreement Among Great Plains Energy Incorporated and Affiliates ("Tax Allocation Agreement"). The Tax Allocation Agreement was put in place to ensure that each subsidiary received benefit for all tax attributes when used by the consolidated group and to ensure that all subsidiaries paid any tax liabilities it incurred or got benefit for any tax credits or NOLs it generated, but only when incurred or used by the consolidated group. This method most accurately represents the economics and the cash flow that actually occurs when a consolidated return is filed.[282]

[280] *Id.* at p.8.
[281] *Id.* at p. 8-9.
[282] *Id.* at p. 16.

198. In its calculations, KCPL has used the actual amount of cost-free capital it actually received; it has used the amounts reflected on its financial records. These amounts reflect the actual cash that KCPL has received in connection with the claiming of its tax deductions.[283]

199. MECG proposes to reduce the NOL carryforward ADIT asset by computing the NOL amounts on a KCPL "stand-alone" basis instead of using the amounts computed under the Tax Allocation Agreement. This proposed adjustment would involve imputing an additional amount of cost-free capital equal to the additional amount that would have been received as of the end of the true-up period had KCPL filed in this stand-alone basis. This approach would produce more cost-free capital than KCPL actually received, thereby reducing the amount of deferred tax asset included in rate base.[284]

**Conclusions of Law and Decision**

MECG has proposed an adjustment that would reduce KCPL's rate base amount as a result of reducing the NOL carryforward ADIT asset by computing the NOL amounts on a KCPL "stand-alone" basis instead of using the amounts computed under the Tax Allocation Agreement. MECG suggests that the Commission's affiliate transaction rule may be used to justify a change in the way the NOL deferred tax assets are computed for KCPL. Commission Rule 4 CSR 240-20.015(2) states:

> (2) Standards.
> (A) A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if –

[283] *Id.* at p. 14
[284] *Id.*

1. It compensates an affiliated entity for good or services above the lesser of –

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or

2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of –

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation.

Section 4 CSR 240-20.015(1)(B) defines affiliate transaction as:

> B. Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, …

The Commission has ruled on this issue in a recent case with a very similar fact situation. In that case, the Commission stated that "[t]he Commission's affiliate transaction rules do not apply in this situation because there is no transaction involved. The affiliate transaction rules are intended to control transfers of goods or services between regulated utilities and their affiliates… where there is no transaction, the restrictions of the rule have no meaning."[285] The Commission finds that the affiliate transaction rule does not apply to this situation.

In that prior case, where Ameren Missouri used the consolidated NOL as allocated to the utility under a tax allocation agreement between the subsidiaries of a consolidated group, the Commission stated that:

> Ameren Missouri proposes to use the NOLC [net operating loss carryforward] it has actually accumulated rather than a hypothetical NOLC proposed by MIEC and supported by Staff, MIEC advocates a policy that arrangements between affiliates should always be interpreted in a manner that benefits ratepayers, even if that results in a detriment to the utility. There is no basis in law or fact for such a policy. The Commission must balance the interests of ratepayers and shareholders to set just and reasonable rates. Ameren Missouri's position is fair and will be adopted.

[285] Report and Order, ER-2014-0258, *In the Matter of Union Elec. Co., d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Elec. Serv.*, 320 P.U.R.4th 330 (Apr. 29, 2015).

MECG attempts to distinguish the prior case by alleging that the Tax Allocation Agreement to which KCPL is obligated does not benefit KCPL or its ratepayers. Even if no benefits have accrued to KCPL in the recent past, that does not mean that KCPL and its ratepayers will not benefit in the future. There is no evidence in the record showing that KCPL has attempted to manipulate its tax obligations to take advantage of ratepayers, and the Commission will not question management decisions made by the company with regard to its tax filings under such a tax allocation agreement. The Commission concludes the proposed adjustment to the computation of ADIT assets related to net operating losses should be rejected.

## K. Class cost of service, rate design, and tariff rules

1. **Class cost of service-production plant- What methodology should the Commission use to allocate fixed production plant costs among customer classes?**
2. **Rate design**
   a. **What methodology is most reasonable for allocating net cost of service among the customer classes in this case?**
   b. **How should any revenue increase be allocated among rate schedules?**
   c. **What, if any, interclass shift in revenue responsibilities should the Commission make?**

### Findings of Fact

200. A class cost of service study is a method by which utility costs and revenues are reconciled across different customer classes. In general, utilities incur three categories of costs: 1) customer-related costs, which are costs associated with connecting customers to the distribution system, metering usage and other customer support functions; 2) energy-related costs, which are costs that tend to change with the amount of electricity sold; and 3) demand-related costs, which are costs associated with meeting maximum electricity demands.[286]

[286] Ex. 303, Dismukes Direct, p. 4-6.

201. KCPL has invested almost $8.7 billion in its various production, transmission and distribution facilities. Of this, over 63 percent is associated with KCPL's investment in its various methods of generating electricity. [287]

202. Separate class cost of service studies were provided by KCPL, Staff, OPC, MECG/MIEC, and the U.S. Department of Energy.[288]

203. The Commission benefits from the presentation of alternative class cost of service studies, but those study results should only be used as a guide.[289]

204. On June 16, 2015, some of the parties filed a *Non-Unanimous Stipulation and Agreement on Certain Issues* ("Rate Design Agreement"), which addressed issues relating to class cost of service, rate design, and tariffs. That Rate Design Agreement stated, in part, that:

> **Class Cost of Service, Production Plant:** The Signatories agree that the Commission should allocate any increase to revenue requirement resulting from this case as an equal percentage increase to all the classes. Given that an equal percent revenue allocation is consistent with some party recommendations contained on the record, the Signatories do not believe that the Commission needs to make specific findings as to the appropriate methodology for allocating production plant costs among the customer classes.
>
> **Rate Design:** The Signatories agree that the appropriate methodology, in this case, for most reasonably allocating net cost of service among the customer classes, for allocating revenue increase among rate schedules, and for interclass shifts in revenue responsibilities, should be an equal percentage increase to all customer classes.

The Rate Design Agreement is attached hereto as Attachment A and incorporated herein. KCPL objected to the Rate Design Agreement.

[287] Ex. 201, Staff Accounting Schedules, Schedule 2, p. 6-7.
[288] Ex. 135, Rush Rebuttal, p. 45.
[289] Ex. 220, S. Kliethermes Surrebuttal, p. 1.

## Conclusions of Law and Decision

Based on the evidence in this case, the Commission finds that acceptance of the provisions of the Rate Design Agreement on these issues is a fair and reasonable resolution of these issues, since an equal percent revenue allocation is consistent with some party recommendations. The Commission adopts the provisions of the Rate Design Agreement stated above.

**3. Residential customer charge- At what level should the Commission set KCPL's residential customer charge?**

## Findings of Fact

205. The residential customer charge is designed to include those costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, a portion of costs associated with meter investment, and the service line.[290]

206. KCPL proposes to increase the customer charge for the residential class from $9.00 to $25.00, an increase of approximately 178 percent for those customers.[291]

207. KCPL's residential customer-related costs are $11.88 per month, which is based on the results of Staff's class cost of service study.[292]

208. KCPL requests that the Commission include as part of the customer charge additional costs for local facility equipment, which are costs for the secondary distribution system and line transformers.[293]

[290] Ex. 202, Staff Rate Design and Class Cost of Service Report, p. 34.
[291] Ex. 303, Dismukes Direct, p. 14.
[292] Ex. 247, Affidavit of R. Kliethermes to correct testimony.
[293] Ex. 135, Rush Rebuttal, p. 20-22.

209. KCPL's proposal to include local facility equipment costs in the residential customer charge is inconsistent with its own class cost of service study. That study defines local facility equipment as demand-related, and those types of costs are typically recovered through a demand charge for those customers that are demand-metered. However, residential customers are not demand-metered, so their demand-related costs are usually recovered through energy charges, not monthly customer charges.[294]

210. The signatory parties to the Rate Design Agreement recommended that the Commission decline to increase the current customer charge of $9.00 per month.

**Conclusions of Law and Decision**

Customer-related costs are generally recovered through the customer charge, which serves to prevent higher usage customers from subsidizing lower usage customers, sends all customers more accurate energy pricing signals, and provides more stable and predictable funding for utilities' fixed costs. Other costs are recovered through volumetric rates that vary with the amount of electricity used. Staff's class cost of service study determined that the costs related to residential customers are $11.88 per month. While KCPL requests that additional costs related to local facility equipment be included in the customer charge, the Commission finds that inclusion of those additional costs would be inappropriate because that request is inconsistent with KCPL's own class cost of service study.

Determining an appropriate customer charge is a question of rate design, not a question of the company's revenue requirement. Any increase in the company's customer charge should be accompanied by a decrease in volumetric rates so that, in theory, the company recovers the same amount of revenue. The Commission considers that an

[294] Ex. 305, Dismukes Surrebuttal, p. 8, See also, Ex. 218, R. Kliethermes Surrebuttal, p. 2-4.

important goal of rate design is to recover costs from those who cause the costs to be incurred. Therefore, the Commission concludes that the appropriate residential customer charge is $11.88 per month, based on Staff's cost of service study.

**4. Residential energy charge- At what level should the Commission set KCPL's residential energy charges?**

## Findings of Fact

211. In KCPL's rate design proposal for the residential class, the company has made a number of adjustments, particularly to the winter rate block structures. In KCPL's last rate case, off-peak winter rate schedules were providing less than their cost of service. The Commission ordered that certain rates blocks within the class should be increased by an additional five percent.[295]

212. In this case, KCPL is proposing to decrease some of the very rates that the Commission previously ordered to increase. Because a class cost of service study shows that the off-peak winter rate schedules are providing a higher return than the on-peak summer rate schedules, decreasing the rates at this time may have unintended results.[296]

213. In the Rate Design Agreement, the signatory parties agreed that, "[w]ith regard to the residential energy charge, the Signatories agree that after accounting for the continuation of the existing customer charges, the residential energy charges will be increased by the same percentages to achieve required revenues."

## Conclusions of Law and Decision

The Commission finds that KCPL's proposed adjustments regarding the residential energy charges are inappropriate due to possible unintended results. The Commission finds that acceptance of the provisions of the Rate Design Agreement on this issue is a fair

[295] Ex. 303, Dismukes Direct, p. 40.
[296] *Id.* at p. 41.

and reasonable resolution of the issue. Since the Commission has decided to increase the residential customer charge, that provision will need to be modified slightly. The Commission concludes that after accounting for the increase in the existing customer charges, the residential energy charges will be increased by the same percentages to achieve required revenues.

5. **Time of day – should the time of day rate be frozen from the addition of future customers (KCPL proposal) or should KCPL be required to file modified time of day tariff provisions in its next rate case?**
6. **Special rates-two-part time-of-use- Should the two-part time of use rate be eliminated from the addition of future customers (KCPL proposal) or should KCPL file a modified two-part time of use tariff provisions in its next rate case?**
7. **Real time pricing tariffs – should the real time pricing rate be frozen from the addition of future customers or should KCPL file modified real time pricing tariff provisions in its next rate case?**

## Findings of Fact

214. KCPL proposes to freeze availability of the residential time-of-use rate because it only has 38 customers and does not perform as it should.[297] KCPL also proposes to freeze two special rates, the two-part time-of-use and real time pricing tariffs, because they are not used or no longer functional.[298]

215. KCPL opposes imposing a new time-of-use rate because it is beginning two projects that will fundamentally impact a time-of-use design, the AMI metering roll-out and the implementation of a new billing system. KCPL cannot commit to a schedule for a new time-of-use tariff because it needs more information about these new system projects and possible impacts to integrated resource planning and MEEIA programs.[299]

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[297] Ex. 134, Rush Direct, p. 66.
[298] *Id.* at p. 59.
[299] Ex. 135, Rush Rebuttal, p. 61.

216. The Division of Energy proposes that two-part time-of-use and real time pricing tariffs remain available and that KCPL be required to submit revised tariffs and supporting documentation in its next rate case.[300]

217. In the Rate Design Agreement, the signatory parties agreed that:

> Regarding time of day rates, the Signatories agree that current residential and other special two-part time-of-day or real time pricing tariffs remain available, and the Signatories would request that the Commission order Kansas City Power & Light Company to complete a study regarding these issues within 2 years in which no party is obligated to support the findings of that study or any proposed tariff design as a result of that study.

**Conclusions of Law and Decision**

KCPL has requested that the Commission freeze the residential time-of-use rates, two-part time-of-use, and real time pricing tariffs in this proceeding and not require KCPL to file new tariffs in its next rate case. The Commission agrees that these rates should be frozen from the addition of future customers for the present time. However, it is clear that all of these rates need to be redesigned, and at least the time-of-use tariff is far too important in meeting the goals of MEEIA and providing customer choices for energy efficiency and bill savings to redesign at an unknown time in the future. The Commission concludes that KCPL should complete a study regarding all of these issues within two years of the effective date of this order.

**8. Should the ResB rate structure be changed to make it consistent with ResA and ResC rate structures?**

**Findings of Fact**

218. The residential class has three main sub-class rate classifications – general use (ResA), one meter general use and space heat (ResB), and two meter rate with general use on one meter and a separate meter for space heating (ResC).[301]

[300] Ex. Hyman Rebuttal, p. 32.

219. Staff has recommended a rate structure change to ResB to make it consistent with ResA and ResC rate structures, to which KCPL agrees.[302]

220. In the Rate Design Agreement, the signatory parties stated that "[t]he Signatories agree to allow modification to the structure of the ResB rate to add an intermediate block rate which will be set equal to the first block rate to make it consistent with the ResA and ResC rate structures."

**Conclusions of Law and Decision**

Based on the evidence in this case, the Commission finds that acceptance of the provisions of the Rate Design Agreement on this issue is a fair and reasonable resolution of the issue. The Commission adopts the provisions of the Rate Design Agreement stated above.

9. **Commercial and industrial –**
   a. **SG, MG, LP and LGS energy charges – at what level should the Commission set KCPL's SG, MG, LP and LGS energy charges?**
   b. **SG, MG, LP and LGS separate meter space heating energy charges and the first energy block rate for the winter rates – at what level should these energy charges be set?**
   c. **Should the Commission adopt MIEC/MECG's rate design proposal for the LGS and LP rate classes, or some a variant of it?**

**Findings of Fact**

221. KCPL's Large General Service ("LGS") and Large Power Service ("LP") tariffs consist of a series of charges differentiated by voltage level. There are separate charges for service at secondary voltage, service at primary voltage, service at substation voltage, and service at transmission voltage. The rates charged at the higher voltage levels are

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[301] Ex. 202, Staff Rate Design and Class Cost of Service Report, p. 3.
[302] *Id.*

lower than the rates charged at the lower voltage levels in order to recognize differences in cost of service.[303]

222. In KCPL's LGS and LP rate schedules, the specific energy charges to be applied to a particular customer's usage decrease as the customer's load factor increases. Energy usage is charged in a sequential manner, so that energy is first billed at the initial 180 hour energy block; any usage in excess of this is billed at the second 180 hour energy block; and any remaining usage is billed at the tail block rate. In order to receive the benefit of the lower energy charges in the second energy block and the tail block, customers must first fill the preceding blocks and pay for energy at the associated higher energy rate.[304]

223. These tariffs collect revenue through, among others, a demand and energy charge, but KCPL is currently collecting a large portion of its fixed costs through LGS and LP energy charges, rather than just collecting its variable costs.[305]

224. In the Rate Design Agreement, the signatory parties agreed as follows:

> Except as provided in the following paragraph, as rate design relates to Commercial and Industrial classes the Signatories agree with the following as it relates to section B(e)(1)-(3) and section (B)(f)(1) and (3) in the *Issues List*: the following rate components of each class be increased across-the-board for each class on an equal percentage basis after:
> • Increasing the first winter energy block rate of the frozen All-Electric Service rate schedules for the SGS, MGS, and LGS rate classes increasing by an additional 5%;
> • Changing the winter second and third SGS all electric block rates to match the winter second and third general service SGS block rates.
>
> As explained in the pre-filed Direct Cost of Service and Rate Design testimony of Maurice Brubaker, at pages 32-33, the general service LGS and LP second block energy rates shall receive 75% of the applicable class percentage increases and there shall be no increase to the tail blocks of the general service LGS and LP energy rates. Any remaining increase in revenue requirement for these classes shall be collected through an equal percentage increase in the customer, demand and first energy blocks.

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303 Ex. 554, Brubaker Direct-Rate Design, p. 28.
304 *Id.* at p. 29.
305 *Id.* at p. 30-31.

## Conclusions of Law and Decision

Based on the evidence in this case, the Commission finds that acceptance of the provisions of the Rate Design Agreement on these issues is a fair and reasonable resolution of the issues. The Commission adopts the provisions of the Rate Design Agreement stated in paragraph 225 above.

### 10. Special interruptible – should the special interruptible rate be frozen from the addition of future customers?

## Findings of Fact

225. KCPL has proposed to freeze or eliminate the special interruptible rate.[306]

226. In the Rate Design Agreement, the signatory parties state that "[t]he Signatories do not oppose Kansas City Power & Light Company's request to eliminate the special interruptible rate."

## Conclusions of Law and Decision

Based on the evidence in this case, the Commission finds that acceptance of the provisions of the Rate Design Agreement on this issue is a fair and reasonable resolution of the issue. The Commission adopts the provisions of the Rate Design Agreement stated above, and the special interruptible rate is eliminated.

### 11. Tariff rules and regulations- Should the return check charge be applied to payment forms beyond checks (electronic payments)?

## Findings of Fact

227. KCPL has a large number of customers who no longer use paper checks for payment, but instead use electronic payment methods.[307]

228. KCPL has proposed to revise its tariff to extend the return payment charge to all forms of payment received by the company in the event of insufficient funds.[308]

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[306] Ex. 134, Rush Direct, p. 59.
[307] Ex. 135, Rush Rebuttal, p. 63.

229. Staff supports KCPL's proposal[309], and no other party has provided testimony or evidence on this issue.

**<u>Conclusions of Law and Decision</u>**

KCPL's request to extend the return payment charge to all forms of payment received by the company in the event of insufficient funds is reasonable. The Commission concludes that KCPL's tariff should be revised such that the return check charge shall be applied to payment forms beyond checks.

**12. Tariff rules and regulations- Should the collection charge be increased to reflect the cost of this service?**

**<u>Findings of Fact</u>**

230. KCPL has proposed to revise its tariff to increase the collection charge from $25 to $30 for in-field payments to reflect the cost of the service and to make the charge consistent with the current GMO collection charge.[310]

231. Staff supports KCPL's proposal[311], and no other party has provided testimony or evidence on this issue.

**<u>Conclusions of Law and Decision</u>**

KCPL requests to increase the collection charge for in-field payments. KCPL argues that this increase is to reflect the cost of the service and to make the charge consistent with the current GMO collection charge. The Commission concludes that KCPL has not adequately explained the need for this increased charge, and so has failed to meet its burden of proof to demonstrate that the increase is necessary. The Commission denies the request to increase the collection charge, and it will remain at $25.00.

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[308] *Id.*
[309] Ex. 233, Murray Surrebuttal, p. 2.
[310] Ex. 135, Rush Rebuttal, p. 63.
[311] Ex. 233, Murray Surrebuttal, p. 2.

### 13. Economic development rider/urban core development rider – Should the Commission approve the Division of Energy's proposal to link MEEIA participation to receipt of EDR and UCD incentives?

**Findings of Fact**

232. KCPL's economic development rider ("EDR") is designed to encourage industrial and commercial business development in Missouri and retain existing load where possible. The urban core development rider ("UCD") has the purpose of encouraging industrial and commercial business development within a specific section of KCPL's service territory.[312] Only four KCPL customers participate in the EDR rider.[313]

233. Division of Energy proposes that KCPL's EDR and UCD riders be changed to require that customers participate in applicable MEEIA programs to be eligible for taking service under the special EDR and UCD rates.[314] The Division of Energy altered its proposal to make it easier for customers to opt-out of MEEIA programs and still receive the special EDR and UCD rates.[315]

234. The EDR was re-designed in October 2013 to make the rider more functional for customers.[316]

235. The Division of Energy's proposal would be nearly impossible to administer because the proposal requires participation in all cost-effective energy efficiency programs.[317]

**Conclusions of Law and Decision**

The Division of Energy recommends that the Commission require KCPL to link MEEIA participation with the receipt of EDR and UCD incentives. The MEEIA statute,

312 Ex. 354, Lohraff Direct, p. 8-9.
313 Ex. 555, Brubaker Rebuttal, p. 23.
314 *Id.* at p. 4.
315 Ex. 355, Lohraff Surrebuttal, p. 5.
316 Ex. 136, Rush Surrebuttal, p. 30.
317 Ex. 135, Rush Rebuttal, p. 65.

Section 393.1075.7, RSMo, allows certain large users of electricity to opt out of participation in MEEIA programs, and the Division of Energy has amended its proposal to make it easier for such customers to opt-out and still receive EDR and UCD rates. However, the evidence showed that this proposal would be difficult for KCPL to administer. The EDR and UCD programs do not have high participation at this time, and adding further restrictions to this recently re-designed program would be counter-productive. In a recent Ameren Missouri rate case, File No. ER-2014-0258, this Commission rejected a very similar proposal and instead decided to establish a collaborative to examine this issue more closely. The Commission concludes that this proposal should be rejected, as well.

**14. Should KCPL be required to establish a working group to review its Standby Service Tariff to ensure that rates are cost-based and reflect best practices?**

**Findings of Fact**

236. Properly designed standby rates can facilitate efficiency gains, energy independence and demand-side management opportunities associated with combined heat and power ("CHP") technologies. Standby rates are a key factor in determining the cost-effectiveness of such CHP projects.[318]

237. KCPL has a standby rate tariff, which went into effect in 1997 and was revised in 2013.[319]

238. Standby rate tariffs for The Empire District Electric Company and Ameren Missouri are currently under review by stakeholders.[320]

239. In the Rate Design Agreement, the signatory parties agreed that "a working group should be formed to review KCP&L's Standby Service Tariff for the purposes of 1) ensuring that the design of standby rates and the terms and conditions of service are

[318] Ex. 354, Lohraff Direct, p. 12.
[319] *Id.*
[320] *Id.*

consistent with best practices and 2) to develop recommendations on cost-based rate levels. Signatories request that the Commission order KCP&L to file a new Standby Service Tariff in its next general rate case."

**Conclusions of Law and Decision**

While the standby rate is important for CHP projects, there has been no adequate showing that the existing KCPL tariff is deficient. The Commission finds it is not mandatory that KCPL to file a new standby rate tariff in its next general rate case. The Commission will not adopt the provision above in the Rate Design Agreement. However, since the standby rate tariffs of other electric utilities are currently under review, the Commission concludes that KCPL should complete a study regarding this issue within two years of the effective date of this order.

## L. Revenues

**Findings of Fact**

240. In Section K, subsection 9 above, the Commission adopted provisions of the Rate Design Agreement regarding rate design for the LGS and LP classes for commercial and industrial customers. This provision recovers the bulk of the LGS and LP class revenue increase from this case through the second block energy rates for those classes, but has no increase for the third block energy rates.

241. This provision creates the potential for some customers to benefit from switching to a different and more advantageous rate schedule.[321]

242. KCPL should have the opportunity to earn its revenue requirement when customers are switching rates schedules due to rate design shifts.[322]

[321] Ex. 238, Scheperle Rebuttal, p. 14; Transcript, Vol. 10, p. 447-48.
[322] *Id.*

243. Staff estimated that an adjustment of no more than $250,000 should be made for possible LGS customers switching rates.[323]

244. KCPL estimated that the company could lose revenues of approximately $590,000 due to rate switching from the rate design provision in the Rate Design Agreement. KCPL's estimate is more credible than the Staff estimate because KCPL looked at all commercial and industrial customers who may switch rates, while Staff only looked at the Large Power Class.[324]

245. On August 3, 2015, Staff and KCPL filed a *Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, and Rate Switcher Revenue Adjustments* ("True-Up Agreement"), which attempted to 1) resolve all issues relating to weather normalization, rate revenues, and the resulting class billing determinants used in developing rates for all rate classes, and 2) assign a revenue shortfall of $500,000 for rate switchers in the LGS and LP rate classes in order to account for any of those customers migrating to a different rate schedule to receive more advantageous pricing as a result of the Rate Design Agreement. Since OPC objected to the True-Up Agreement, it is a joint position statement, but Staff and KCPL urge the Commission to adopt its terms. OPC only objected to the provision relating to rate switching. The True-up Agreement is attached hereto as Attachment B and incorporated herein by reference.

**Conclusions of Law and Decision**

KCPL's estimate was that it would lose revenues of approximately $590,000 if certain customers switched to a rate with more advantageous pricing. The True-Up Agreement proposed an adjustment of $500,000 to account for rate switching customers which is a more reasonable estimate, as not all customers would be likely to switch rates at

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[323] Ex. 253, R. Kliethermes True-Up Direct, p. 5.
[324] Ex. 167, Rush True-Up Rebuttal, p. 2-3.

the same time. Based on the evidence in this case, the Commission finds that acceptance of all the provisions of the True-Up Agreement on the issues contained therein is a fair and reasonable resolution of those issues. The Commission adopts the provisions of the True-Up Agreement in their entirety as stated in Attachment A to this Report and Order.

## M. Low income weatherization

### Findings of Fact

246. The Commission has authorized KCPL to participate in a program to weatherize homes of low-income residents called the Income Eligible Weatherization Program ("Program"). KCPL operates the Program independently of a similar federal weatherization program and provides funding to community action agencies that deliver such services within KCPL's service territory.[325]

247. In Missouri, only KCPL and GMO operate their weatherization programs under the Missouri Energy Efficiency Investment Act ("MEEIA"). Other regulated electric utilities fund their weatherization services through customer contributions in base rates. Base rate recovery is preferable to recovery through MEEIA because regulated electric utilities offer MEEIA on a voluntary basis, and there is no guarantee that weatherization programs will be offered if a utility does not participate in MEEIA.[326]

248. Ninety-nine percent of MEEIA weatherization funds go to single-family homes. Funding the Program through KCPL's base rates would allow Program funds to be made available to multi-family homes.[327]

[325] Ex. 350, Buchanan Direct, p. 9.
[326] *Id.* at p. 10-11.
[327] Transcript, Vol. 20, p. 1970-71.

249. Before collecting Program funds through MEEIA, KCPL collected Program funds through base rates. KCPL presently has a surplus of Program funds previously collected through base rates.[328]

**Conclusions of Law and Decision**

Since the Program is an important service that benefits low-income residents, the Commission considers continuity of the Program to be a valuable goal. To avoid any continuity problems in the future, the Commission finds that collecting Program funds through base rates to be preferable. This will also provide for consistency across the state, as most other regulated electric utilities collect weatherization funds through base rates. The Commission concludes that KCPL should resume recovery of low-income weatherization program costs in base rates following the conclusion of KCPL's MEEIA Cycle 1 and cease recovery of these costs in future MEEIA applications. With regard to any surplus Program funds recovered previously through base rates, the unexpended low-income weatherization program funds collected through KCPL's base rates should be used to offset any expenditures relating to the Program.

## N. Economic Relief Pilot Program

**Findings of Fact**

250. KCPL originally established the Economic Relief Pilot Program ("ERPP") to deliver energy affordability benefits to KCPL's qualifying low-income customers. The ERPP currently provides up to $50 in bill credit for up to 1,000 participants. One half of the funding for the ERPP comes from shareholders and the other half from ratepayers. Between

[328] Ex. 200, Staff Report-Revenue Requirement Cost of Service, p. 138-39.

January 2013 and September 2014, the average number of monthly participants was approximately 949, and 20,355 customer bills received an ERPP credit.[329]

251. In this case, KCPL proposes to double the amount of ERPP funding to $630,000 for shareholders and $630,000 for ratepayers. KCPL is also proposing to raise the current limit of participants to 1,500 and increase the available monthly bill credit to $65.[330]

252. Currently any unused ERPP funds are to be used to offset demand-side management programs. KCPL recently received approval to offer its demand-side management programs under MEEIA, so KCPL proposes to direct any future unused ERPP funds to its Dollar-Aide program, which helps families pay heating, cooling and water bills during difficult financial times.[331] Staff recommends that any unspent funds be made available for future ERPP expenditures.[332]

253. The current ERPP tariff makes the program available to customers with an annual household income no greater than 185 percent of the Federal Poverty Level. Due to the Federal Poverty Level increasing in 2009, Staff recommends that KCPL change the eligibility requirement to 200 percent of the Federal Poverty Level.[333]

254. KCPL does not oppose Staff's recommendations to expand the eligibility requirements and make unspent ERPP funds available for future ERPP expenditures.[334]

**Conclusions of Law and Decision**

The ERPP is an important and valuable program to assist low-income customers with bill affordability. KCPL should be commended for establishing this program and

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329 Ex. 134, Rush Direct, p. 42-43.
330 *Id.*
331 *Id.* at p. 44.
332 Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 138.
333 Ex. 200, Staff Report- Revenue Requirement Cost of Service, p. 137.
334 Ex. 135, Rush Rebuttal, p. 6.

recommending that it be expanded. The Commission concludes that the ERPP should be expanded as proposed by KCPL by doubling the funding, increasing the number of participants, and increasing the available bill credit. The eligibility requirements should be changed to 200 percent of the Federal Poverty Level, and any unspent ERPP funds should be made available for future ERPP expenditures to ensure these funds are used as they were intended and not for some other purpose.

### O. True-up issues

**Findings of Fact**

255. KCPL has proposed two adjustments to its revenue requirement for events that occur outside of the true-up period in this case: 1) KCPL has proposed to remove two capacity agreements that expire on September 30, 2015; and 2) KCPL has included the potential cost increases for transmission expenses from Independence Power & Light's membership in SPP.[335]

256. In this case, the true-up period ended on May 31, 2015. A true-up is used to include the impacts of known and measurable material events that occur after the update period and that are much closer to when rates are going to be in effect to be reflected in the determination of rates.[336] The term "known and measurable" relates to items or events affecting a utility's cost of service that must have been realized (known) and must be calculable with a high degree of accuracy (measurable).[337]

257. On April 13, 2015, SPP filed with the FERC, on behalf of the City of Independence, Missouri, revisions to its Open Access Transmission Tariff to implement the annual transmission revenue requirement for Independence Power & Light ("IPL") to be

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[335] Ex. 251, Featherstone True-Up Rebuttal, p. 3.
[336] *Id.* at p. 5, 7.
[337] Ex. 256, Lyons True-Up Rebuttal, p. 11.

included in KCPL's transmission pricing zone. On June 12, 2015, FERC approved those tariff revisions, subject to refund, with an effective date of June 1, 2015.[338]

258. FERC has not yet determined if SPP's tariff will result in just and reasonable rates, which further decision is subject to additional hearing and settlement procedures.[339]

259. KCPL has protested the FERC decision and continues to argue in the ongoing FERC proceeding that it should not be required to pay any increased net transmission expenses resulting from IPL's membership in SPP. KCPL intends to challenge the assignment of IPL's costs to KCPL up to and including a final non-reviewable FERC order.[340]

260. KCPL has made estimates of the impact of this FERC decision on its transmission revenues and expenses, but KCPL has not received an invoice from SPP with specific costs related to the addition of IPL in KCPL's SPP pricing zone and does not expect to receive such an invoice until at least September 2015.[341]

261. KCPL has two capacity sales agreements with the Kansas Municipal Energy Agency ("KMEA") that will expire on September 30, 2015. By these agreements, KCPL agreed to provide energy service to KMEA on a firm capacity basis.[342]

262. The net impact on KCPL's cost of service from these two contracts is $1.453 million (total company basis).[343]

## **Conclusions of Law and Decision**

KCPL has proposed that the Commission should include in its revenue requirement costs incurred from IPL's membership in SPP and exclude revenues from KCPL's

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[338] *Id.* at p. 6.
[339] *Id.*
[340] Ex. 164, Ives True-Up Rebuttal, p. 8, 10.
[341] Ex. 256, Lyons True-Up Rebuttal, p.7; Transcript, Vol. 21, p. 2030-31.
[342] Ex. 251, Featherstone True-Up Rebuttal, p. 12.
[343] Ex. 163, Crawford True-Up Rebuttal, p. 7.

agreements with the KMEA. For such true-up adjustments, those costs and revenues must be known and measurable. The IPL costs imposed on KCPL are not yet known and measurable because KCPL is continuing to fight those costs in FERC's ongoing proceedings, and FERC has not yet provided KCPL with an invoice that specifies any cost increases. The revenues that KCPL will lose at the expiration of the KMEA contracts on September 30, 2015, are known and measurable because as of May 31, 2015 it was known that the contracts will expire on September 30, and the amount of revenues lost is measurable with accuracy. The Commission concludes that any increased costs KCPL may incur related to IPL's membership in SPP should be excluded from the revenue requirement and that the revenues from the expiration of the KMEA contracts should also be excluded.

**Decision Summary**

In making this decision as described above, the Commission has considered the positions and arguments of all of the parties. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the material was not dispositive of this decision.

Additionally, KCPL provides safe and adequate service, and the Commission concludes, based upon its independent review of the whole record, that the rates approved as a result of this order support the provision of safe and adequate service. The revenue increase approved by the Commission is no more than what is sufficient to keep KCPL's utility plants in proper repair for effective public service and provide to KCPL's investors an opportunity to earn a reasonable return upon funds invested.

By statute, orders of the Commission become effective in thirty days, unless the Commission establishes a different effective date.[344] In order that this case can proceed expeditiously, the Commission will make this order effective on September 15, 2015.

**THE COMMISSION ORDERS THAT:**

1. The Motion to Strike Pleadings, Reject Tariff Sheets, and Strike Testimony filed by Missouri Industrial Energy Consumers and the Office of the Public Counsel on June 10, 2015, is denied.

2. The tariff sheets submitted on October 30, 2014, by Kansas City Power & Company, assigned Tariff Nos. YE-2015-0194 and YE-2015-0195, are rejected.

3. Kansas City Power & Light Company is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order. Kansas City Power & Light Company shall file its compliance tariff sheets no later than September 8, 2015.

4. Kansas City Power & Light Company shall file the information required by Section 393.275.1, RSMo 2000, and Commission Rule 4 CSR 240-10.060 no later than September 8, 2015.

5. The Staff of the Missouri Public Service Commission shall file its recommendation concerning approval of Kansas City Power & Light Company's compliance tariff sheets no later than September 14, 2015.

6. Any other party wishing to respond or comment regarding Kansas City Power & Light Company's compliance tariff sheets shall file the response or comment no later than September 14, 2015.

[344] Section 386.490.3, RSMo.

7. The *Non-Unanimous Stipulation and Agreement on Certain Issues* filed by some of the parties on June 16, 2015, is attached hereto as Attachment A and incorporated herein by reference.

8. Staff and Kansas City Power & Light Company's *Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, and Rate Switcher Revenue Adjustments* filed on August 3, 2015, is attached hereto as Attachment B and incorporated herein by reference.

9. This Report and Order shall become effective on September 15, 2015, except that Ordered Paragraphs 3, 4, 5 and 6 shall become effective upon issuance.

**BY THE COMMISSION**

Morris L Woodruff

Morris L. Woodruff
Secretary

Hall, Chm., Stoll, Kenney, and
Rupp, CC., concur and certify
compliance with the provisions of
Section 536.080, RSMo.
Coleman, C., abstains.

Dated at Jefferson City, Missouri,
on this 2nd day of September, 2015

# BEFORE THE PUBLIC SERVICE COMMISSION
# OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area | ) ) ) ) ) | **File No. ER-2019-0374**<br>Tariff No. YE-2020-0029 |

# REPORT AND ORDER

**Issue Date:** July 1, 2020

**Effective Date:** July 11, 2020

ACC-D-3

# BEFORE THE PUBLIC SERVICE COMMISSION
# OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area | ) ) ) ) ) | **File No. ER-2019-0374** Tariff No. YE-2020-0029 |

## REPORT AND ORDER

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**SENIOR REGULATORY LAW JUDGE:** John T. Clark

# REPORT AND ORDER

## I. Procedural History

**Tariff Filings, Notice, and Intervention**

On August 14, 2019, The Empire District Electric Company (Empire) filed tariff sheets designed to implement a general rate increase for utility service. The submitted tariff (Tracking No. YE-2020-0029) would have increased Empire's annual electric revenues by approximately $26.5 million dollars (approximately 4.93 percent)[1]. The tariff had an effective date of September 13, 2019. In order to allow sufficient time to study the effect of the tariff sheets and to determine if the rates established by those sheets are just, reasonable, and in the public interest, the tariff sheets were suspended until July 11, 2020. The Commission directed notice of the filings and set an intervention deadline. The Commission granted intervention requests from the following entities: the Missouri Department of Natural Resources - Division of Energy (DE), Midwest Energy Consumers Group (MECG), Natural Resources Defense Council (NRDC), Sierra Club, Renew Missouri Advocates (Renew Missouri), National Housing Trust (NHT), The Empire District Electric SERP Retirees (EDESR), The Empire District Retired Members & Spouses Association (EDRA), and the International Brotherhood of Electrical Workers Local Unions No. 1464, and 1474 (IBEW).

The Commission adopted a test year encompassing the twelve months ending on March 31, 2019, updated through September 30, 2019, with a true-up period to include known and measurable information through January 31, 2020. On December 9, 2019, The Office of the Public Counsel (OPC) filed *Public Counsel's Motion to Modify Test Year*

[1] Ex. 4P, Richard Corrected Direct, Schedule SDR-9.

*to Include Isolated Adjustments Related to Retirement of Asbury*. OPC requested the Commission modify the ordered test year to include isolated adjustments for the retirement of the Asbury coal-fired power plant. OPC asked to include isolated adjustments to account for Empire moving Asbury's retirement from no later than June 2020, to no later than March 2020. The Commission denied OPC's request. March is outside the true-up cutoff period and the Commission determined that Asbury's retirement is best addressed in Empire's next rate case. Instead, the Commission ordered the parties to submit items for potential inclusion in an Accounting Authority Order (AAO) to capture the financial impacts of that retirement for consideration in Empire's next rate case.

**Local Public Hearings**

The Commission conducted local public hearings in Bolivar, Joplin, and Branson, Missouri.[2]

**Global Stipulation and Agreement**

On April 15, 2020, Empire, the Commission's Staff (Staff), MECG, EDESR, EDRA, NRDC, NHT, and Renew Missouri submitted their *Global Stipulation and Agreement* (Agreement). On April 16, 2020, OPC objected to the Agreement. Pursuant to Commission rule, the Agreement became the joint position statement of the signatory parties. However, no party is bound by the Agreement and all the issues addressed in the Agreement remain for determination after hearing.[3]

**Evidentiary Hearing**

On October 17, 2019, the Commission scheduled an evidentiary hearing for April 14-17, and 20-22, 2020. On March 13, 2020, Missouri Governor, Mike Parson, declared

[2] Transcript, Vols 3, 4, 6-8.
[3] Commission Rule 20 CSR 4240-2.115(2)(D).

a state of emergency because of the -COVID-19 viral pandemic. On March 23, 2020, the Governor closed Missouri state buildings to all but essential employees. The Commission responded to the closure by preparing to conduct the evidentiary hearing electronically by videoconference.

On April 3, 2020, Staff submitted on behalf of the parties a *Progress Report and Request for Extension of Filing Dates*. In that pleading the parties agreed to waive cross examination of all witnesses and asked the Commission to cancel the evidentiary hearing and decide all issues on the record. The Commission suspended the hearing to allow for submission of the case on the record, and altered the procedural schedule to accommodate new filing dates and the Commission's questions for the parties.

**Case Submission**

The Commission admitted the testimony of 58 witnesses, received 321 exhibits into evidence, and took official notice of certain matters. Briefs were filed according to the modified procedural schedule. The final reply briefs were filed on May 18, 2020, and the case was deemed submitted for the Commission's decision on that date.[4]

## II. General Matters

**MECG Motion to Strike, and Empire's Objections to Evidence**

MECG filed its *Motion to Strike Portions of OPC Surrebuttal Testimony* on April 12, 2020, asking the Commission to strike portions of OPC surrebuttal testimony on the basis that the testimony was not responsive to matters raised in rebuttal testimony. The Commission denies MECG's motion to strike testimony.

[4] "The record of a case shall stand submitted for consideration by the commission after the recording of all evidence or, if applicable, after the filing of briefs or the presentation of oral argument." Commission Rule 20 CSR 4240-2.150(1).

On May 6, 2020, Empire filed its *Objections to Offers of Evidence*, objecting to specific testimony offered by OPC witnesses relating to the retirement of the Asbury power plant. The Commission has previously determined that the test year in this case would not be modified to include isolated adjustments related to the retirement of Asbury, and that isolated true-up adjustments for Asbury's retirement would not be included in this general rate proceeding.[5] However, that determination does not make all testimony related to Asbury's retirement irrelevant to every issue before the Commission in this case. Because the testimony in question contains evidence relevant to pending issues, Empire's objections to specific OPC testimony are overruled and that testimony is admitted into the record.

**General Findings of Fact**

The Commission finds that any given witness's qualifications and overall credibility are not dispositive as to each portion of that witness's testimony. The Commission gives each item or portion of a witness's testimony individual weight based upon the detail, depth, knowledge, expertise, and credibility demonstrated with regard to that specific testimony. Consequently, the Commission will make additional specific weight and credibility decisions throughout this order as to specific items of testimony as are necessary.[6] Any finding of fact reflecting that the Commission has made a determination between conflicting evidence is indicative that the Commission attributed greater weight

[5] File No. ER-2019-0374, Order Denying Motion for Reconsideration, issued February 19, 2020.
[6] Witness credibility is solely a matter for the fact-finder, "which is free to believe none, part, or all of the testimony". *State ex rel. Public Counsel v. Missouri Public Service Comm'n*, 289 S.W.3d 240, 247 (Mo. App. 2009).

to that evidence and found the source of that evidence more credible and more persuasive than that of the conflicting evidence. [7]

1. Empire is engaged in the business of the manufacture, transmission, and distribution of electricity. Empire provides electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma. Empire's service area includes approximately 10,000 square miles in southwest Missouri and the adjacent corners of the three surrounding states, Kansas, Oklahoma, and Arkansas. Empire is regulated by the utility regulatory commissions in all four states and by the Federal Energy Regulatory Commission (FERC). [8]

2. OPC is a party to this case pursuant to Section 386.710(2), RSMo[9], and by Commission Rule 20 CSR 4240-2.010(10).

3. Staff is a party to this case pursuant to Commission Rule 20 CSR 4240-2.010(10).

4. Empire provides electric generation, transmission, and distribution services to approximately 173,000 retail electric customers in portions of Arkansas, Kansas, Missouri, and Oklahoma. Empire provides electric service to approximately 155,000 customers in Missouri.[10]

5. Empire merged with Liberty Utilities on January 3, 2017. Empire and Liberty Utilities are subsidiaries of Liberty Utilities, Co (LUCo). LUCo is wholly owned by

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[7] An administrative agency, as fact finder, also receives deference when choosing between conflicting evidence. *State ex rel. Missouri Office of Public Counsel v. Public Service Comm'n of State*, 293 S.W.3d 63, 80 (Mo. App. 2009)

[8] Ex. 1, Baker Direct, page 3.

[9] Unless otherwise stated, all statutory citations are to the Revised Statutes of Missouri, as codified in the year 2016 and subsequently revised or supplemented.

[10] Ex. 1, Baker Direct, page 3.

Algonquin Power & Utilities Company (APUC). Liberty Utilities provides gas, water and sewer service in Missouri and other jurisdictions.[11]

6. To determine the appropriate level of utility rates, the Commission must calculate a revenue requirement for Empire. The revenue requirement is the incremental increase or decrease in revenues based on measurement of the utility's current total cost of service compared to its current revenue levels under existing rates the utility needs to provide safe and reliable service, as measured using Empire's existing rates and cost of service.[12]

7. To determine the appropriate revenue requirement for an investor owned utility, the first step is to calculate the cost of service (COS) for that utility[13]. The COS for a regulated utility can be defined by the following formula:[14]

Cost of Service = Cost of Providing Utility Service

or

COS = O + (V-D)R where,

COS = Cost of Service

O = Operating Costs (Fuel, Payroll, Maintenance, etc.), Depreciation and Taxes

V = Gross Valuation of Property Required for Providing Service (including plant and additions or subtractions of other rate base items)

D = Accumulated Depreciation Representing Recovery of Gross Depreciable Plant Investment

[11] Ex. 101, Staff Direct Report, page 3.
[12] Ex. 100, Bolin Direct, page 4.
[13] Ex. 100, Bolin Direct, pages 3-4.
[14] Ex. 100, Bolin Direct, pages 3-4

V – D = Rate Base (Gross Property Investment less Accumulated Depreciation = Net Property Investment)

(V – D)R = Return Allowed on Rate Base

Once the cost of service is determined, a cost of capital analysis is done to determine the appropriate rate of return for the utility.[15]

8. The test year for this case is the twelve months ending March 31, 2019, updated through September 30, 2019.[16]

9. The Commission also selected a true-up period ending January 31, 2020, to account for any significant changes in Empire's cost of service that occurred after the end of the test year period but prior to the tariff operation of law date.[17]

10. A normalization adjustment is an adjustment made to reflect normal, on-going operations of the utility. Revenues or costs that were incurred in the test year that are determined to be atypical or abnormal will get specific rate treatment and generally require some type of adjustment to reflect normal or typical operations. The normalization process removes abnormal or unusual events from the cost of service calculations and replaces those events with normal levels of revenues or costs.[18]

11. An annualization adjustment is made to a cost or revenue shown on the utility's books to reflect a full year's impact of that cost or revenue.[19]

12. The calculated cost of service is then compared to net income available from existing rates to determine the revenue requirement, which is to determine the

[15] Ex. 100, Bolin Direct, page 6.
[16] Ex. 100, Bolin Direct, page 5: and File No. ER-2019-0374, Order Setting Procedural Schedule and Other Procedural Requirements, October 17, 2019.
[17] Ex. 100, Bolin Direct, page 6
[18] Ex. 101, Staff Direct Cost of Service Report, page 2.
[19] Ex. 101, Staff Direct Cost of Service Report, page 2.

incremental change in Empire's rate revenues required to cover its operating costs and provide a fair return on investment used in providing utility service.[20]

**General Conclusions of Law**

A. Empire is an "electrical corporation" and a "public utility" as defined in Sections 386.020(15) and 386.020(43), RSMo, respectively, and as such is subject to the personal jurisdiction, supervision, control and regulation of the Commission under Chapters 386 and 393 of the Missouri Revised Statutes.

B. The Commission's subject matter jurisdiction over Empire's rate increase request is established under Section 393.150, RSMo.

C. Sections 393.130 and 393.140, RSMo, mandate that the Commission ensure that all utilities are providing safe and adequate service and that all rates set by the Commission are just and reasonable.

D. Section 393.150.2, RSMo, makes clear that at any hearing involving a requested rate increase the burden of proof to show the proposed increase is just and reasonable rests on the corporation seeking the rate increase. As the party requesting the rate increase, Empire bears the burden of proving that its proposed rate increase is just and reasonable. In order to carry its burden of proof, Empire must meet the preponderance of the evidence standard.[21] In order to meet this standard, Empire must

[20] Ex. 100, Bolin Direct, page 4.
[21] *Bonney v. Environmental Engineering, Inc.*, 224 S.W.3d 109, 120 (Mo. App. 2007); *State ex rel. Amrine v. Roper*, 102 S.W.3d 541, 548 (Mo. banc 2003); *Rodriguez v. Suzuki Motor Corp.*, 936 S.W.2d 104, 110 (Mo. banc 1996), citing to, *Addington v. Texas*, 441 U.S. 418, 423, 99 S.Ct. 1804, 1808, 60 L.Ed.2d 323, 329 (1979).

convince the Commission it is "more likely than not" that Empire's proposed rate increase is just and reasonable.[22]

E. In determining whether the rates proposed by Empire are just and reasonable, the Commission must balance the interests of the investor and the consumer.[23] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[24]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[25]

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[22] *Holt v. Director of Revenue, State of Mo.*, 3 S.W.3d 427, 430 (Mo. App. 1999); *McNear v. Rhoades*, 992 S.W.2d 877, 885 (Mo. App. 1999); *Rodriguez v. Suzuki Motor Corp.*, 936 S.W.2d 104, 109 -111 (Mo. banc 1996); *Wollen v. DePaul Health Center*, 828 S.W.2d 681, 685 (Mo. banc 1992).
[23] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).
[24] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).
[25] *Bluefield,* at 692-93.

The Supreme Court has further indicated:

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

F. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[27]

Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[28]

G. The test year is a central component in the ratemaking process. Rates are usually established based upon a historical test year which focuses on four factors: (1) the rate of return the utility has an opportunity to earn; (2) the rate base upon which a

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[26] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).
[27] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).
[28] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

return may be earned; (3) the depreciation costs of plant and equipment; and (4) allowable operating expenses.[29]

H. A test year is used as the starting point for determining the basis for adjustments that are necessary to reflect annual revenues and operating costs in calculating any shortfall or excess of earnings by the utility. Adjustments, such as annualization and normalization adjustments, are made to the test year results when the unadjusted results do not fairly represent the utility's most current annual level of existing revenue and operating costs.[30]

I. A historical test year is used because the past expenses of a utility can be used as a basis for determining what rate is reasonable to be charged in the future.[31]

J. The use of a true-up audit and hearing in ratemaking is a compromise between the use of a historical test year and the use of a projected or future test year.[32] It involves adjustment of the historical test year figures for known and measurable subsequent or future changes.[33] However, the true-up is generally limited to only those accounts necessarily affected by some significant known and measurable change, such as a new labor contract, a new tax rate, or the completion of a new capital asset. The true-up is a device employed to reduce regulatory lag, which is "the lapse of time between a change in revenue requirement and the reflection of that change in rates."[34]

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[29] *State ex rel. Union Electric Company v. Public Service Comm'n*, 765 S.W.2d 618, 622 (Mo. App. 1988).
[30] Ex. 100, Bolin Direct, page 5.
[31] *See State ex rel. Utility Consumers' Council of Missouri, Inc. v. Public Service Comm'n*, 585 S.W.2d 41, 59 (Mo. banc 1979).
[32] *St. ex rel. Missouri Public Service Comm'n v. Fraas,* 627 S.W.2d 882, 887-888 (Mo. App. 1981).
[33] *St. ex rel. Missouri Public Service Comm'n v. Fraas,* 627 S.W.2d 882, 888 (Mo. App. 1981). .
[34] *In the Matter of St. Louis County Water Company*, File No. WR-96-263 (*Report & Order*, issued December 31, 1996), at p. 8; 5 Mo. P.S.C. 3d 341, 346.

## III. Disputed Issues

### 1) Rate of Return—Return on Equity, Capital Structure, and Cost of Debt

#### Findings of Fact

13. The rate of return (ROR) is the overall cost of capital; that is, the cost of debt and the Commission-selected return on equity (ROE) weighted by the capital structure.[35]

14. An authorized ROE is a Commission-determined return granted to monopoly industries, allowing them the opportunity to earn fair and reasonable compensation for their investments.[36]

15. Cost of equity (COE) is a market-determined minimum return investors are willing to accept for their investment in a company, compared to returns on other available investments.[37]

16. COE is not directly observable; it must be estimated based upon both quantitative and qualitative information.[38]

17. A utility's COE is implied by the price investors are willing to pay for a share of stock.[39]

18. COE and ROE are not equivalent, a COE is determined by what investors are willing to pay for a share of stock, while Commission authorized ROEs have been consistently higher than COEs.[40]

[35] Ex. 101, Staff Direct Report, page 3.
[36] Ex. 101, Staff Direct Report, page 2.
[37] Ex. 101, Staff Direct Report, page 6.
[38] Ex. 10, Hevert Direct, page 15.
[39] Ex. 210, Murray Direct, page, 2
[40] Ex. 210, Murray Direct, page 2.

19. Three financial analysts offered recommendations regarding an appropriate ROE. Robert B. Hevert testified on behalf of Empire. Hevert is a Partner and Rates, Regulation & Planning Practice Leader at ScottMadden Management Consultants . Prior to that Hevert was Managing Partner of Sussex Economic Advisors, LLC. He holds a Bachelor of Science degree in Finance from the University of Delaware and a Master of Business Administration with a concentration in finance from the University of Massachusetts. He also holds the Chartered Financial Analyst designation.[41] Hevert recommends a ROE of 9.95 percent with a range of 9.80 percent to 10.60 percent.[42]

20. Peter Chari is employed as a Utilities Regulatory Auditor for the Financial Analysis Department of the Staff. He holds a Bachelor of Arts in Economics and a Master of Business Administration in Finance from North Central College. He was awarded the professional designation of Certified Rate of Return Analyst by the Society of Utility and Regulatory Financial Analysts.[43] Staff witness Chari recommends a ROE of 9.25 percent with a range of 9.05 percent to 9.80 percent.[44]

21. David Murray is employed as a Utility Regulatory Manager for OPC. Prior to employment with the OPC, Murray was the Utility Regulatory Manager of the Financial Analysis Department for Staff from 2009 through June 30, 2019. Murray started work at the Commission as a Financial Analyst in June 2000. Prior to that, he was employed by the Missouri Department of Insurance in a regulatory position. He holds a Bachelor of Science degree in Business Administration with an emphasis in Finance and Banking, and Real Estate from the University of Missouri-Columbia and a Master's degree in

[41] Ex. 36, Hevert Direct, Attachment A.
[42] Ex. 36, Hevert Direct, page 2.
[43] Ex. 101, Staff Direct Report, Appendix 1.
[44] Ex. 101, Staff Direct Report, pages 18-19.

Business Administration from Lincoln University. In April 2007, he was awarded the professional designation of Certified Rate of Return Analyst by the Society of Utility and Regulatory Financial Analysts. He also holds the Chartered Financial Analyst designation.[45] Murray recommends a ROE of 9.25 percent with a range of 8.50 percent to 9.25 percent.[46]

22. Common methods to determine a COE and an authorized ROE are the Discounted Cash Flow Models (DCF), Capital Asset Pricing Models (CAPM), risk premium models, and comparative earnings analyses.[47]

23. Each methodology has certain inherent disadvantages that may lead to unreasonable estimates. DCF's main disadvantage revolves around estimation of growth rate, and CAPM's main issue of concern is estimation of market risk premiums ("MRP").[48]

24. The constant growth DCF model assumes that an investor buys a stock for an expected total return rate, which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate). The Constant Growth DCF model expresses the COE as the discount rate that sets the current price equal to expected cash flows.[49]

25. The Bond Yield Plus Risk Premium approach assumes that investors require a risk premium over the cost of debt as compensation for assuming the greater risk of common equity investment. The model is expressed as a bond yield plus equity risk premium.[50]

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[45] Ex. 210, Murray Direct, Schedule DM-D-1.
[46] Ex. 210, Murray Direct, page 2.
[47] Ex. 108, Chari Rebuttal, page 2.
[48] Ex. 108, Chari Rebuttal, page 2.
[49] Ex. 36, Hevert Direct, page 47.
[50] Ex. 36, Hevert Direct, Glossary, page ii.

26. FERC determined that risk premium models (like the Bond Yield Plus Risk Premium) are less reliable that DCF and CAPM models.[51]

27. The CAPM is based on capital market theory that the total risk of a company consists of market (systematic) risk and business-specific (unsystematic) risk. Investors are only compensated for systematic risk because investors can avoid unsystematic risk by diversifying their portfolios. Systematic risks are unanticipated events in the economy, such as economic growth, changes in interest rates, demographic changes, etc., that affect almost all assets to some degree. The required risk premium for incurring the market risk as it relates to the investment is determined by adjusting the market risk premium by the beta of the stock or portfolio. The adjusted risk premium is then added to a risk-free rate to determine the COE.[52]

28. Empire's witness Hevert used a Constant Growth DCF, a CAPM and Empirical CAPM (ECAPM), a Bond Yield Plus Risk Premium, and an Expected Earnings Analysis to determine Empire's recommended ROE.[53]

29. Staff's witness Chari used Constant Growth DCF and CAPM models for COE estimation and recommended ROE.[54]

30. OPC's witness Murray used a multi-stage DCF method, a CAPM model, and he performed simple and logical reasonableness checks of his COE estimates.[55]

31. All three financial analysts used DCF and CAPM models.

[51] Ex. 108, Chari Rebuttal, page 2.
[52] Ex. 210, Murray Direct, page 37-38.
[53] Ex. 36, Hevert Direct, page 4.
[54] Ex. 108, Chari Rebuttal, page 4.
[55] Ex. 210, Murray Direct, page 19.

32. Gross Domestic Product (GDP) is the value of all finished goods and services produced within a country during a given period of time.[56]

33. Utility growth rates are generally consistent with the GDP growth rate.[57]

34. It is unlikely that utilities will grow at a higher rate than the overall economy, because it runs counter to basic economic principles that companies will grow at a rate consistent with the long-term growth rate of the overall economy over the long-term.[58]

35. The long-term nominal GDP growth rate estimate is 4.1 percent (unadjusted for inflation).[59] A higher estimate of nominal GDP growth of 4.4 percent would also be reasonable.[60]

36. The projected long-term nominal GDP growth rate is a reasonable restriction for determining growth rates used to estimate the COE for a regulated electric utility.[61]

37. Hevert's constant growth DCF model assumes that his electric proxy group's dividends will grow perpetually at an average of 5.80 percent, a growth rate that is about 170 basis points higher than the estimated long-term growth rate for the general economy.[62]

38. The constant growth DCF model also assumes dividend payments. Staff found 84 companies that do not pay dividends within the S&P 500 company list that Hevert used. This inflated Hevert's MRPs, which resulted in an inflated COE.[63]

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[56] Ex. 36, Hevert Direct, Glossary, page ii.
[57] Ex. 101, Staff Direct Report, page 7.
[58] Ex. 108, Chari Rebuttal, page 7.
[59] Ex. 108, Chari Rebuttal, page 7.
[60] Ex. 101, Staff Direct Report, page 16.
[61] Ex. 101, Staff Direct Report, page 16.
[62] Ex. 108, Chari Rebuttal, page 7.
[63] Ex. 108, Chari Rebuttal, pages 9-10.

39. Hevert's recommended ROE of 9.95 percent is 56 basis points higher than the national average of authorized ROE.[64] The Commission finds this ROE would be excessive because his constant growth DCF results are based on unsustainable long-term growth rates, and both his DCF and CAPM include inflated MRPs.[65]

40. Staff notes that if Hevert had calculated MRPs correctly his CAPM COE estimates would range from 6.02 percent to 7.60 percent, not 8.66 percent to 9.76 percent, and his ECAPM COE estimates would range from 6.88 percent to 8.50 percent, not 10.19 percent to 11.05 percent.[66] In addition, ECAPM is not known as a generally accepted method used by investors to estimate the COE to apply to expected cash flows/dividends from utility stocks.[67]

41. The projected long-term nominal GDP growth rate is a reasonable restriction for determining growth rates used to estimate the COE for a regulated electric utility.[68]

42. Staff's witness Chari used a more reasonable constant growth rate of 4.20 percent to 5.00 percent to determine a COE estimate of between 7.34 percent to 8.14 percent.[69]

43. Staff determined that an authorized ROE of 9.25 percent would be appropriate[70]

44. OPC's COE estimate is between 5.35 percent to 6.75 percent.[71]

[64] Ex. 108, Chari Rebuttal, pages 6-7.
[65] Ex. 108, Chari Rebuttal, pages 8-10.
[66] Ex. 108, Chari Rebuttal, page 9-10.
[67] Ex. 211, Murray Rebuttal, page 11.
[68] Ex. 101, Staff Direct Report, page 16.
[69] Ex. 101, Staff Direct Report, page 16.
[70] Ex. 108, Chari Rebuttal, page 19.
[71] Ex. 210, Murray Direct, pages 39-40.

45. OPC's witness Murray used a growth rate range of 2.85 percent to 3 percent,[72] which is also less than the nominal GDP growth rate.

46. Both Staff and OPC's financial analysts agree that a 9.25 percent authorized ROE is reasonable. [73] The Commission finds this ROE to be reasonable and based upon realistic economic growth.

47. The Commission has used the "zone of reasonableness standard" for setting an authorized ROE. The point from which the zone of reasonableness extends is a recent industry average of authorized ROE.[74]

48. The 2019 national average of authorized ROE is 9.39 percent.[75]

49. Capital structure represents how a company's assets are financed. Capital structure typically consists of common equity, long-term debt, and short-term debt.[76]

50. Empire recommends the Commission adopt its true-up capital structure, which consists of 53.07 percent common equity and 46.93 long-term debt.[77]

51. Staff recommends the Commission use Empire's capital structure, which consists of 52.43 percent common equity and 47.57 percent long-term debt.[78]

52. OPC recommends the Commission use LUCo's adjusted capital structure consisting of 46 percent common equity and 54 percent long-term debt.[79]

53. In File No. EM-2016-0213 the Commission evaluated a joint application requesting approval of an agreement and plan of merger in which Liberty Sub Corp would

[72] Ex. 212, Murray Surrebuttal/True-Up Direct, page 25.
[73] Ex. 101, Staff Direct Report, page 18; Ex, 210, Murray Direct, page 42; and Ex. 213, Murray Supplemental Surrebuttal, page 3.
[74] Ex. 210, Murray Direct, page 17.
[75] Ex. 108, Chari Rebuttal, pages 6-7.
[76] Ex. 210, Murray Direct, page 5.
[77] Ex. 7, Richard True-up direct, page 21.
[78] Ex. 149, Staff's Recommended Allowed Rate of Return as of September 30, 2019, replacing table 1 of Staff's Direct Report.
[79] Ex. 212, Murray Surrebuttal/True-Up Direct, page 35.

merge with and into Empire and under which Liberty Utilities (Central) Co. would acquire all the common stock of Empire.

54. An unopposed Stipulation and Agreement was submitted In File No. EM-2016-0213 on August 23, 2016 (Merger Stipulation).

55. The Commission's *Order Approving Stipulations and Agreements and Authorizing Merger Transaction* issued on September 7, 2016, in File No. EM-2016-0213 approved the Merger Stipulation finding that under its terms, including the reasonable conditions imposed on the merger transactions contained therein, the merger transaction at issue was not detrimental to the public and should be approved. Condition 5 of the Merger Stipulation states that "If Empire's per books capital structure is different from that of the entity or entities in which Empire relies for its financing needs, Empire shall be required to provide evidence in subsequent rate cases as to why Empire's per book capital structure is the most economical for purposes of determining a fair and reasonable allowed rate of return for purposes of determining Empire's revenue requirement."[80]

56. Staff and OPC relied on the conditions contained in the Merger Stipulation in File No. EM-2016-0213 to protect Empire and its customers from detriments that could occur due to Empire's financing needs being consolidated with the rest of APUC's regulated utilities.[81]

57. Empire creates consolidated financial statements that include all of its operations, including its gas distribution subsidiary, Empire Gas. Empire also creates

[80] Ex. 108, Chari Rebuttal, pages 13-14.
[81] Ex. 212, Murray Surrebuttal and True-up Direct, page 35.

deconsolidated financial statements in which it breaks out Empire Gas' distribution operations from Empire's electric, water and non-regulated operations.[82]

58. Initially both Empire's and Staff's per book capital balances for Empire were based upon Empire's deconsolidated financial statements.[83] As of September 30, 2019, based upon its per books balance sheet LUCo had 53.00 percent common equity and 47.00 percent long-term debt, and based upon its deconsolidated financial statements Empire had 52.90 percent common equity and 47.10 percent long-term debt.[84] Staff's witness, Mr. Chari, subsequently acknowledged that he had inadvertently utilized Empire's deconsolidated capital structure in his analysis, and he clarified that Empire's consolidated capital structure was actually 52.49 percent common equity and 47.51 percent long-term debt.[85]

59. Based upon LUCo's per books balance sheet and Empire's financial statements Staff determined that Empire had the more economical structure based on the equity ratio. Staff witness Chari testified that the higher the equity ratio, the less economical the capital structure is because equity costs more than the other portions of the capital structure.[86]

60. LUCo's per books balance sheet does not include off balance sheet debt supported by LUCo's assets.[87]

61. Before APUC acquired Empire, Empire financed and operated itself and all its affiliates as one entity, that is Empire did not finance and operate Empire Gas as a

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[82] Ex. 211, Murray Rebuttal, page 7.
[83] Ex. 211, Murray Rebuttal, page 7.
[84] Ex. 108, Chari Rebuttal, page 14.
[85] Ex. 109 Chari Surrebuttal, pages 2 and 12.
[86] Ex. 108, Chari Rebuttal, page 14.
[87] Ex. 211, Murray Surrebuttal/True-Up Direct, pages 11-12.

stand-alone entity; therefore, the financial community assessed Empire's risk on a consolidated level, including that of Empire Gas.[88] Thus, Empire's consolidated financial statements should be used to calculate Empire's capital structure.[89]

62. When Empire was a stand-alone company, it had its own financing functions and direct access to capital markets for short and long-term debt. Empire now relies on LUCo for all of its financing functions, which includes access to short-term debt and long-term debt.[90]

63. LUCo has a $500 million credit facility for its short-term debt. LUCo relies on APUC's financing subsidiary, Liberty Utilities Finance GP 1 (LUF), for its long-term debt financing needs. LUF issues debt directly to third-parties on behalf of LUCo and intermediate entities between LUCo and APUC. LUCo guarantees all debt issued by LUF, which includes debt that was issued for the sole purpose of buying equity in LUCo.[91]

64. LUCo unconditionally guarantees $395 million in off balance sheet debt ($135 million issued by Liberty American and $260 million issued by LUF)[92], which is not shown in its' per book value. This off balance sheet debt should be considered when determining whether LUCo's or Empire's capital structure is more economical.[93]

65. The rating agencies recognize the $395 million in guarantees as off balance sheet debt and adjust LUCo's debt to include it.[94]

[88] Ex. 211, Murray Surrebuttal/True-Up Direct, pages 11-12.
[89] Ex. 211, Murray Surrebuttal/True-Up Direct, pages 11-12.
[90] Ex, 210, Murray Direct, pages 6 - 7.
[91] Ex, 210, Murray Direct, pages 7, lines 6-11.
[92] Ex. 212, Murray Surrebuttal/True-Up Direct, page 10, lines 6 – 10, 14-16.
[93] Ex. 212, Murray Surrebuttal/True-Up Direct, page 12.
[94] Ex. 212, Murray Surrebuttal/True-Up Direct, page 17.

66. LUCo uses the off balance sheet debt to fund equity infusion in LUCo, which is ultimately used to fund its regulated utilities.[95]

67. Therefore since LUCo used the $395 million debt to record a higher equity balance on LUCo's balance sheet, not only should this debt be added to the debt recorded on LUCo's balance sheet, but it should also be subtracted from LUCo's equity balance.[96]

68. After adjusting for the $395 million in off balance sheet debt, LUCo's common equity ratio is 46 percent,[97] which is a more economical capital structure than Empire's.[98]

69. The Commission has a history of using LUCo's capital structure for LUCo's affiliate companies. The Commission approved LUCo's capital structure for two of Empire's affiliates, Liberty Utilities (Midstates Natural Gas) and Liberty Utilities LLC (Missouri Water), in File Nos. GR-2014-0152 and WR-2018-0170.[99]

70. Empire is recommending a cost of debt of 4.85 percent, based on Empire's recorded cost of debt at January 1, 2020.[100]

71. Staff adjusted its recommended cost of debt to reflect OPC witness Schallenberg's concern about LUCo's $90 million dollar loan to Empire not being in compliance with the Affiliate Transaction Rule as the interest charged to Empire exceeds LUCo's short-term debt rate used to fund the loan. Staff adjusted its embedded cost of debt recommendation from 4.84 percent to 4.57 percent.[101]

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[95] Ex, 210, Murray Direct, pages 10, Line 12.
[96] Ex, 210, Murray Direct, pages 10, Lines 15 - 17.
[97] Ex, 210, Murray Direct, pages 10, line 20.
[98] Ex, 210, Murray Direct, pages 10, line 24.
[99] Ex. 212, Murray Surrebuttal/True-Up Direct, page 20.
[100] Ex. 7, Richard True-up direct, page 21.
[101] Ex. 130, Chari Surrebuttal, pages 13-14.

72. OPC's witness Murray matched the cost of debt to the capital structure that is actively managed for and used to obtain financing, which is LUCo's.[102] This is appropriate because LUCo's cost of debt matches the financial risk embedded in LUCo's adjusted capital structure of 46 percent common equity and 54 percent long-term debt.[103]

73. Empire's debt financing is now being provided by LUCo and LUF, therefore Empire's credit ratings are not a necessary component for it to access capital.[104]

74. OPC's recommended cost of debt is 4.65 percent based on LUCo's consolidated cost of debt.[105] OPC's recommended cost of debt does not include any affiliate notes, hence no adjustments are necessary.[106]

75. The Commission finds use of LUCo's cost of debt appropriate because it best aligns with the financial risk embedded in LUCo's capital structure.[107]

## Conclusions of Law

A. In determining the rate of return, the Commission must consider Empire's capital structure and cost of debt, the Commission must determine the weighted cost of each component of the utility's capital structure. One component at issue in this case is the estimated cost of common equity capital, or the ROE. Estimating the cost of common equity capital is a difficult task, as academic commentators have recognized.[108] Determining a rate of ROE is imprecise and involves balancing a utility's need to compensate investors against its need to keep prices low for consumers.[109]

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[102] Ex. 212, Murray Surrebuttal/True-Up Direct, page 23; and Ex. 299-17, OPC Reply to Testimony Responding to Commission Questions of David Murray, pages 1-3.
[103] Ex. 210, Murray Direct, pages 14.
[104] Ex. 210, Murray Direct, pages 14.
[105] Ex. 211, Murray Rebuttal, page 10.
[106] Ex. 212, Murray Surrebuttal/True-Up Direct, page 23.
[107] Ex. 211, Murray Rebuttal, page 10; and Ex. 211, Murray Surrebuttal/True-Up Direct, page 23.
[108] See Phillips, *The Regulation of Public Utilities*, Public Utilities Reports, Inc., p. 394 (1993).
[109] *State ex rel. Pub. Counsel v. Pub. Serv. Comm'n*, 274 S.W.3d 569, 574 (Mo. Ct. App. 2009).

B. Missouri court decisions recognize that the Commission has flexibility in fixing the rate of return, subject to existing economic conditions.[110] "The cases also recognize that the fixing of rates is a matter largely of prophecy and because of this, commissions in carrying out their functions, necessarily deal in what are called 'zones of reasonableness', the result of which is that they have some latitude in exercising this most difficult function."[111] Moreover, the United States Supreme Court has instructed the judiciary not to interfere when the Commission's rate is within the zone of reasonableness.[112]

**<u>Decision</u>**

Three financial experts offered testimony in this rate case. Empire's witness Hevert's determination of a recommended ROE of 9.95 percent is excessive. His constant growth DCF ROE relied on an unreasonable assumption that utility growth would substantially exceed the long-term growth rate of the United States economy. This assumption is not credible even under periods of normal economic growth. Both his DCF and CAPM calculations utilized inflated MRPs. Further, his reliance on an ECAPM was not reasonable, as ECAPM is not known as a generally accepted method used by investors to estimate the COE to apply to expected cash flows/dividends from utility stocks.

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[110] *State ex rel. Laclede Gas Co. v. Public Service Commission*, 535 S.W.2d 561, 570-571 (Mo. App. 1976).

[111] *State ex rel. Laclede Gas Co. v. Public Service Commission*, 535 S.W.2d 561, 570 -571 (Mo. App. 1976). In fact, for a court to find that the present rate results in confiscation of the company's private property that court would have to make a finding based on evidence that the present rate is outside of the zone of reasonableness, and that its effects would be such that the company would suffer financial disarray. *Id*.

[112] *State ex rel. Public Counsel v. Public Service Commission*, 274 S.W.3d 569, 574 (Mo. App. 2009). *See, In re Permian Basin Area Rate Cases,* 390 U.S. 747, 767, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968) ("courts are without authority to set aside any rate selected by the Commission [that] is within a 'zone of reasonableness' ").

The remaining two financial analysts each independently arrived at a reasonable ROE for Empire of 9.25 percent, though 9.25 percent was at the top of OPC witness Murray's range and closer to the bottom of Staff witness Chari's range. Both analysts used reasonable growth rates and risk premiums in their analysis to determine their respective ROE recommendations. The Commission finds the testimony of Mr. Murray and Mr. Chari more credible than Mr. Hevert's, and their recommended 9.25 percent ROE to be appropriate.

If Empire's capital structure is different than that of the entity or entities it relies on for its financing needs, Condition 5 of the Merger Stipulation approved in File No. EM-2106-0213 requires Empire to provide evidence in its rate cases as to why its per book capital structure is the most economical for purposes of determining a fair and reasonable allowed rate of return. A primary reason the parties included this requirement was to protect Empire and its customers from detriments that could occur due to Empire's financing needs being consolidated with the rest of APUC's regulated utilities.

Although Empire and Staff arrived at similar positions and both found Empire's capital structure to be the most economical for purposes of complying with Condition 5 of the Merger Stipulation, both of their analysis are flawed and not reliable. Their capital structures were similar because they both inappropriately used LUCo's per book balance sheet capital structure that did not reflect LUCo's off balance sheet debt. Staff determined Empire's capital structure was appropriate based on Empire having the appearance of a more economical capital structure as determined by its per book value capital structure when compared to LUCo's.

The Commission finds OPC's witness Murray more persuasive than either Staff's or Empire's witnesses with regard to capital structure. He appropriately utilized Empire's consolidated capital structure and included LUCo's off balance sheet debt in his capital structure calculations. LUCo's adjusted capital structure is appropriate to use for setting rates in this case because it is more economical than Empire's. Further, use of the affiliated utility's capital structure is not the capital structure the Commission has historically used for other Liberty Utilities companies. Based on this analysis and supported by the facts set out above, LUCo's adjusted capital structure of 46 percent common equity and 54 percent long-term debt is the appropriate capital structure to use in setting rates in this case.

Based upon its determination related to capital structure, the Commission further finds that the cost of long-term debt should be based on LUCo's consolidated embedded cost of long-term debt of 4.65 percent, because it best aligns with the financial risk embedded in LUCo's capital structure.

**2) Rate Design, Other Tariff and Data Issues**

a) Should the GP and TEB rate schedules be fully consolidated?
b) Should the CB and SH rate schedules be partially consolidated?
c) Should "grandfathered" multifamily customers taking service through a single meter be given the option of being served on the CB/SH rate schedule?
d) How should Empire's revenue requirement be allocated amongst Empire's customer rate classes (Class revenues responsibilities)?
e) How should the rates for each customer class be designed?
f) How should any revenue requirement increase or decrease be allocated to each rate class?
g) How should production-related costs be allocated to each rate class?
h) How should plant accounts 364, 366 and 368 be classified?
i) How should primary and secondary distribution plant facility costs be allocated to each rate class?
j) How should General plant facility costs be allocated to each rate class?

**<u>Findings of Fact</u>**

76. Empire's current rate structure includes base rates, a FAC (fuel adjustment clause) factor, Energy Efficiency Cost Recovery (EECR) charge, and a tax reform credit.

The base rates include monthly customer charges, energy charges, and demand charges. For some rate classes, the energy charges vary by season.113

77. Costs included in a customer charge are the costs necessary to make electric service available to the customer regardless of the level of electric service utilized. The costs can include monthly meter reading, billing, postage, customer accounting service expenses, as well as distribution.[114]

78. Energy charges are charges based on the amount of energy used by a customer. Unlike a customer charge, the energy charge will fluctuate based on the kilowatt hour (kWh) of usage and the rate per kWh. Blocks are used to identify when a specific rate per kWh will be charged for a certain level of usage. For instance, while one rate may be applied in a block for usage of 0-600 kWhs, a higher or lower rate may apply to the block of usage above 600 kWh.[115]

79. Empire's current rate design is that contained in the compliance tariffs filed on August 15, 2016, as substituted on August 26, 2016, and approved to become effective as of September 14, 2016 in its last rate case, File No. ER-2016-0023. [116]

80. A Class Cost of Service (CCOS) study is an analysis that apportions a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given class represents the costs that class would pay to produce an equal rate of return to other classes.[117]

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[113] Ex. 26, Lyons Direct, page 5.
[114] Ex. 104, Staff Class Cost of Service Report, page 14.
[115] Ex. 104, Staff Class Cost of Service Report, pages 14-15. Ex. 101, Staff Direct Report, page 33.
[116] Order Approving Compliance Tariffs, issued in File No. ER-2016-0023 on September 6, 2016.
[117] Ex. 208, Marke Rebuttal, page 2.

81. Three CCOS studies were prepared by Staff, Empire and MECG.[118] None of these CCOS studies are reliable due to the unavailability of reliable data needed to establish class and system peaks and billing determinants, and due to a large number of estimated bills.[119] For example, Empire's peak data, which is the basis for the vast majority of the costs allocated in a CCOS, did not appear reasonable.[120]

82. In the past Staff employed an in-house method to allocate costs but because of a lack of data Staff was unable to collect the information necessary for its direct filing.[121]

83. Using Staff's method a CCOS study can normally be assumed to be accurate to around 5 percent plus or minus of each studied class's revenue requirement. However, due to data reliability concerns and large percentages of estimated bills, that is not true in this case.[122]

84. Staff recommends that the General Power (GP) and Total Electric Building (TEB) rate schedules be consolidated because there is no apparent cost-related distinction between them.[123]

85. Empire recognizes that there are some benefits to consolidating the GP and TEB rate schedules, which they identified as[124]:

a. Schedules GP and TEB have identical customer charges and rate structures.

b. Schedules GP and TEB have a similar cost of service.

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[118] Ex. 104, Staff Class Cost of Service Report; Ex.26, Direct Testimony of Timothy S. Lyons; Ex. 650, Direct Testimony of Kavita Maini.
[119] Ex. 120, Kliethermes Rebuttal, pages 2-4, and Ex. 121, Lange Rebuttal, page 21.
[120] Ex. 104, Staff Class Cost of Service Report, page 25.
[121] Ex. 104, Staff Class Cost of Service Report, page 26.
[122] Ex. 136, Lange Surrebuttal, page 13.
[123] Ex. 104, Staff Class Cost of Service Report, pages 3 and 18.
[124] Ex. 28, Lyons Rebuttal CCOS, page 14.

c. Consolidating rates and charges simplifies the Company's rate management and customer communication.

86. Empire's primary concern with the consolidation of GP and TEB rate schedules is customer bill impacts and whether some customers may experience significant bill increases as a result of the change due to the consolidation of GP and TEB rate schedules.[125]

87. Staff recommends the Commercial (CB) and Space Heating (SH) rate schedules be partially consolidated except the charge for non-summer usage in excess of 700 kWh per customer per month.[126]

88. Empire recognizes that there are some benefits to consolidating the CB and SH rate schedules, which they identified as[127]:

a. Schedules CB and SH have identical rate structures and customer charges.

b. The cost of service differences between Schedules CB and SH can be recognized by maintaining distinct winter tail block rates.

c. Potential bill impact concerns related to the proposed rate changes can be addressed by maintaining distinct winter tail block rates.

d. Consolidating rates and charges simplifies the Company's rate management and customer communication.

89. Empire's primary concern with the partial consolidation of CB and SH rate schedules is the customer bill impacts and whether some customers may experience

[125] Ex. 28, Lyons Rebuttal CCOS, page 14.
[126] Ex. 121, Lange Rebuttal, page 22.
[127] Ex. 28, Lyons Rebuttal CCOS, pages 13 - 14.

significant bill increases as a result of the change due to the consolidation of CB and SH rate schedules.[128]

90. Commission Rule 20 CSR 4240-20.050.2 requires that multiple-family dwellings (apartments) built after June 1, 1981, be separately metered. Multiple-family buildings built before June 1, 1981, are grandfathered and continue to be metered from one meter (master metered).[129]

91. Staff has proposed that Empire's tariff be modified to allow master metered customers the option of being served on the CB tariff instead of the Residential tariff.[130]

92. Multiple-family buildings built prior to June 1, 1981, that are master metered are served on the residential tariff and their bill calculated by multiplying the customer charge and KWh block by the number of dwelling units.[131] Because the customer charge is multiplied by the number of dwelling units, the bill may contain customer charges for unoccupied dwelling units.

93. After Advanced Metering Infrastructure (AMI) is set up, Empire will be able to collect better customer usage data. Having this data will improve the quality of their load research and revenue data, which will allow them to implement rate schedules with time variant rate structures.[132]

94. Staff's CCOS report showed the Residential class is contributing within 5 percent of its cost of service, however Staff has acknowledged that its CCOS in this case cannot be assumed to be accurate to within 5 percent plus or minus per class.[133]

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[128] Ex. 28, Lyons Rebuttal CCOS, page 13-14.
[129] Commission Rule 20 CSR 4240-20.050.2.
[130] Ex.104, Staff Class Cost of Service Report, page 34.
[131] Ex.104, Staff Class Cost of Service Report, page 34.
[132] Ex. 121, Lange Rebuttal, page 21.
[133] Ex.104, Staff Class Cost of Service Report, page 32; and Ex. 136, Lange Surrebuttal, page 13.



ACC-D-3

95. Allocation consists of assigning rate base and expense items to rate classes based on the factors that reflect their underlying cost of service.[134]

96. In the past Staff employed an in-house method to allocate costs but because of a lack of data Staff was unable to collect the information necessary for its direct filing.[135]

97. Staff proposed various rates for each customer class; some included maintaining the current rates.[136]

98. An overall goal of rate design is to minimize inter-class subsidies. The revenue requirement should generally be allocated among the customer rate classes in a manner that reflects an aggregate movement toward the system ROR. This is accomplished by assigning a larger increase to classes that produce a lower ROR than the system ROR.[137]

99. MECG proposes that any rate decrease for the LP and, GP and SC-P rate classes be reflected by reducing both blocks of the energy charge of each class. All other charges (customer and demand charges) used for the collection of fixed costs would remain at current levels. [138] If a rate increase is ordered, MECG proposes that energy charges should remain at current levels and the demand charges be proportionally increased to correct the over recovery of fixed costs from the energy charges.[139]

100. Empire supports MECG's recommendation to apply any rate increases for the LP rate class to the billing demand and facility charges and to apply any rate

[134] Ex. 26, Lyons Direct, page 10.
[135] Ex. 104, Staff Class Cost of Service Report, page 26.
[136] Ex.104, Staff Class Cost of Service Report, pages 14-23.
[137] Ex. 26, Lyons Direct, page 28.
[138] Ex. 350, Maini Direct, page 36.
[139] Ex. 350, Maini Direct, page 36.

decreases to the energy charges. Empire supports MECG's recommendation to apply any rate decreases to the energy charges.[140]

101. Empire anticipates filing its next rate case in the third quarter of 2020.[141]

102. The appropriate allocation method for production-related costs will vary case-to-case with utility characteristics and data availability.[142]

103. Allocation consists of assigning rate base and expense items to rate classes based on the factors that reflect their underlying cost of service.[143]

104. Customer use of utility-owned equipment is related to the voltage needs of the customer. Before allocating distribution plant costs to customer rate classes, the individual distribution plant accounts are classified between customer and demand related costs. Demand-related costs are divided between primary demand, reflecting customers served at primary voltage, and secondary demand, reflecting customers served at secondary voltage.[144]

105. Distribution plant Accounts 364 through 370 involve both demand-related and customer-related costs. The customer-related component of distribution facilities - the number of poles, transformers, meters, and miles of conductor - are directly related to the number of customers on the utility's system, but the size of each of these items are associated with the level of energy that they deliver over time. The amounts in distribution system accounts need to be allocated between customer-related and demand-related classifications.[145]

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[140] Ex. 28, Lyons Rebuttal CCOS, page 10.
[141] Ex. 1017, Richard Supplemental, page 12.
[142] See Staff's Position Statement, P. 13, filed April 17, 2020.
[143] Ex. 26, Lyons Direct, page 10.
[144] Ex.104, Staff Class Cost of Service Report, page 27-28.
[145] Ex.104, Staff Class Cost of Service Report, page 28.

106. Empire used the Minimum-Size Method to calculate the customer related component of accounts 364, 366, and 368. The Minimum-size Method assumes that a minimum sized distribution system can be built to serve minimum demand requirements of customers. The minimum system costs are allocated to each rate class based on the number of customers. Distribution plant in excess of the minimum system reflect the cost of serving customer peak demands. Peak demand costs are also allocated to each rate class based on customer peak demands.[146]

107. Staff used the Zero-Intercept Cost Minimum method to calculate the customer related component of Accounts 364, 366, and 368. The zero-intercept cost study tries to identify the portion of plant related to a hypothetical no-load state. It relates installed cost to current carrying capacity or demand rating, and creates a curve for various sizes of the equipment involved, using regression techniques, and extends the curve to a no-load intercept. The cost related to the zero-intercept is the customer related component.[147]

108. For the remaining classification of Account 364, Staff relied on Empire's study provided within its workpapers.[148]

109. Staff used Empire's cost of $6.90 per foot to calculate the customer-related portion of plant Account 366. The remaining classification of Account 366 relied upon Empire's study provided within its workpapers.[149]

110. For the remaining classification of Account 368, Staff relied on Empire's study provided within its workpapers.[150]

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[146] Ex. 26, Lyons Direct, pages 17-18.
[147] Ex.104, Staff Class Cost of Service Report, page 28.
[148] Ex.104, Staff Class Cost of Service Report, page 28.
[149] Ex.104, Staff Class Cost of Service Report, page 29.
[150] Ex.104, Staff Class Cost of Service Report, page 29.

111. Staff allocated the costs of the primary distribution facilities based on the sum of each class's coincident peak demands measured at primary voltage for each month of the test period. Staff only allocated distribution primary costs to those customers that used these facilities.[151]

112. Staff allocated the costs of the secondary distribution system, including line transformers, based on the sum of each class's coincident peak demands at secondary voltage.[152]

113. Empire allocates general plant related costs based on the composite allocation of all labor-related production, transmission, distribution, customer accounts, and customer service O&M expenses. Empire states that this allocation methodology is well established in industry literature and is consistent with the Company's prior rate case filing.[153]

114. Staff relies on the Regulatory Assistance Project (RAP), *Electric Cost Allocation for a New Era* to support its analysis of allocations. General plant costs support all of a utility's functions.[154]

115. Staff maintains its class revenue responsibility and rate design variations as a reasonable outcome in this case, regardless of the unavailability of a typically reliable CCOS from any party.[155]

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[151] Ex.104, Staff Class Cost of Service Report, page 29.
[152] Ex.104, Staff Class Cost of Service Report, page 29.
[153] Ex. 26, Lyons Direct, page 27.
[154] Ex. 104, Staff Class Cost of Service Report, Appendix 3, page 42.
[155] Ex. 136, Lange Surrebuttal, page 13.

## Conclusions of Law

C. Empire has the burden of proof to show that its proposed tariffs are just and reasonable, including the reasonableness of its rate design.[156] Just because a company derives a higher rate of return from one class than another does not necessarily render those rates unjust or unreasonable.[157]

D. Commission rule 20 CSR 4240-20.050(2), states that each residential and commercial unit in a multiple-occupancy building, construction of which has begun after June 1, 1981, shall have installed a separate electric meter for each residential or commercial unit.

E. The Public Utility Regulatory Act of 1978, 16 U.S.C. 2601, requires that individual meters be installed in new buildings to encourage the conservation of energy by the occupants of those buildings. This is codified in Missouri law in the Commission's Rule 20 CSR 4240-20.050(2).

F. Empire's current tariff's Residential Service (RG) Schedule states that if the RG schedule is used for service through a single meter to multiple-family dwellings within a single building, each Customer charge and kWh block will be multiplied by the number of dwelling units served in calculating each month's bill. It also provides that service is furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.[158]

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[156] *See, e.g., State ex rel. Monsanto Company v. Public Service Commission,* 716 S.W.2d 791 (Mo. 1986) "Laclede filed the tariffs here in question using the existing rate design. In the suspension order and notice of proceedings dated January 18, 1983, the Commission noted that the Company bore the burden of proof before the Commission and ordered the Company 'to provide evidence and argument sufficient for the Commission to determine . . . the reasonableness of the Company's rate design.'" *Id.* at 795. See also *In re Empire District Electric Company*, 13 Mo P.S.C. 3d 350, Commission File No. ER-2004-0570, Report and Order (March 10, 2005).

[157] *Midwest Gas Users Ass'n v. Kansas SCC,* 595 P.2d 735, 747 (Kan. App. 1979).

[158] PSC Mo. No. 5, Sec. 1, 19th Revised Sheet No 1.

## Decision

There are potential advantages to consolidating the GP and TEB rate schedules and to partially consolidating the CB and SH rate schedules, but at this time the billing impact of those changes is unknown. Staff's assertions that the billing impacts would be mitigated are based upon Staff's revenue requirement and CCOS study. However, Staff has similarly indicated that none of the CCOS studies submitted in this case are reliable for ratemaking. Therefore, the Commission finds that it is not appropriate to consolidate rate schedules at this time based on the questionable accuracy of the CCOS studies. Since Empire has indicated that it will file a rate case in the third quarter of 2020, the Commission will order Empire to submit an impact analysis regarding the alignment of the CB and SH, and GP and TEB rate schedules in its next rate case.

Some apartment buildings built before June 1, 1981, receive service from Empire through a single meter. Those buildings' bills are generated by multiplying the customer charge and kWh blocks by the number of dwelling units in the building. This simulates the charges that would be paid in a building with individual meters for each dwelling unit. Empire's tariff states that service is furnished for the sole use of the customer and will not be resold or redistributed. This means that no portion of the bill can be collected by the building owner/landlord from tenants for utilities, and the property owner/landlord will pay a monthly customer charge on unoccupied dwelling units. There may be advantages to these customers having the option of being billed under the CB tariff. The Commission will order Empire to modify its tariff to permit master-metered customers the option of being served on the CB tariff instead of the Residential tariff.

The quality of the CCOS studies used by the parties in this rate case is such that those studies are not sufficiently accurate for the purpose of significantly altering Empire's current rate design. The large number of estimated bills and the lack of confidence in any CCOS study make it difficult to determine the appropriate rate design revenue requirement allocations. Therefore, the Commission finds that it is not appropriate to make any changes to the revenue requirement allocations at this time. The issue of the appropriate residential customer charge was resolved by the parties and in not an issue in dispute in this proceeding. The current residential customer charge will remain in effect. Based on this analysis, and supported by the facts set out above, the Commission determines that Empire has not met its burden to establish that its proposed changes to rate design are reasonable. Staff's CCOS is not reliable, so there is insufficient evidence to justify changing the current allocations for class revenue responsibilities. The Commission finds that it is appropriate to apply any revenue increase or decrease to the energy charge and not the customer charge. Any increase or decrease should be applied to each energy block in proportion to the revenue generated by that block. Additionally the Commission determines that any decrease for the LP and GP rate classes shall reduce the energy blocks of each class.

Both Staff and Empire described their methods of classifying accounts 364, 366, and 368. Empire appears to want the Commission to endorse a methodology for classifying these accounts and allocating primary and secondary distribution as well as general plant facility costs. The Commission agrees with Staff that no specific allocation method should be ordered or endorsed because the appropriate method will vary from case to case based on the utility's characteristics and available data. However, because of the concerns about the reliability of the data involved, the Commission determines that Empire has not met its burden of proof and will adopt the account classifications and the allocation of primary and secondary plant facility costs as well as general plant facility costs as determined by Staff.

**3) Jurisdictional Allocation Factors**

**Findings of Fact**

116. Jurisdiction allocation factors are used to allocate demand-related and energy-related costs between each of the retail jurisdictions served by Empire; Missouri, Arkansas, Oklahoma, and Kansas, as well as the wholesale jurisdiction in Missouri and Kansas.[159]

117. Generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands, plus required reserves. Accordingly, the contribution of each of Empire's three jurisdictions: Missouri Retail Operations, Non-Missouri Retail Operations, and Wholesale Operations, coincident to the system peak demand, i.e., each jurisdiction's demand at the time of the system peak, is the appropriate basis on which to allocate these facilities. Thus, the term coincident peak refers to the load, generally in kWs or megawatts (MW), in each of the jurisdictions that coincides with Empire's overall system peak recorded for the time period in the corresponding analysis.[160]

118. Demand refers to the rate at which energy is delivered to a system to match the customer's load requirements. Staff utilized a twelve coincident peak methodology to determine demand allocation.[161] Use of a twelve coincident peak method is appropriate

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[159] Ex. 101, Staff Direct Report, pages 32-33.
[160] Ex. 101, Staff Direct Report, page 33.
[161] Ex. 101, Staff Direct Report, page 33.

for an electric utility, such as Empire, that experiences similar system peak demands in both summer and winter months.[162]

119. Staff calculated the demand allocation factor for Missouri at .8393, for non-Missouri at .1065, and for wholesale operations at .0542.[163]

120. Energy allocation includes variable expenses, like fuel, that are allocated to jurisdictions based upon energy consumption. The energy allocation factor is a ratio of normalized annual kWh used by each jurisdiction as compared to Empire's normalized total usage. There are adjustments for anticipated growth, annualization, and non-normal weather. [164]

121. Staff calculated the energy allocation factor for Missouri at .8240, for non-Missouri at .1109, and for wholesale operations at .0651.[165]

122. Empire criticized Staff for annualizing retail energy kWh for Missouri and Arkansas as well as the Wholesale jurisdiction, but not for Kansas and Oklahoma. Staff responded that Non-Missouri Retail Operations is comprised of the sum of the other states in which Empire provides retail electric service other than Missouri, and the energy allocation factors for each jurisdiction is the ratio of the normalized annual kWh usage of a particular jurisdiction to the total normalized Empire kWh usage.[166]

123. Empire appears to have applied multiple methods when determining jurisdictional allocations, but provided no persuasive explanation as to why those allocations are correct.[167]

[162] Ex. 101, Staff Direct Report, page 33.
[163] Ex. 101, Staff Direct Report, page 34.
[164] Ex. 101, Staff Direct Report, page 34.
[165] Ex. 101, Staff Direct Report, page 34.
[166] Ex. 128, Bax Surrebuttal, page 2.
[167] Ex. 57, Jurisdictional Allocators Workpaper.

124. Although now owned by Liberty Utilities, Empire still serves the same states it did prior to the acquisition.

**Conclusions of Law**

No additional Conclusions of Law are required for this issue

**Decision**

The Commission finds that Staff's jurisdictional allocations are the appropriate factors to be used to calculate Empire's cost of service.

**4) WNR and SRLE Adjustment Mechanisms**

**Findings of Fact**

125. Empire proposes to implement a weather normalization rider (WNR) to adjust customer bills to reflect normal weather conditions. For weather periods that are milder than normal, a WNR charge would be applied to the bill. For weather periods that are harsher than normal, a credit would be applied to the bill. Empire asserts this rider would prevent over or under-collection by the Company during abnormal weather conditions.[168] Empire has requested the WNR as a Revenue Stabilization Mechanism (RSM) under Section 386.266.3 RSMo.[169]

126. In the alternative Staff has proposed its Sales Reconciliation to Levelized Expectations (SRLE), a rate mechanism designed to account for weather and conservation for customers served on the Residential, CB, and SH rate schedules. This tariff mechanism is similar to the Volumetric Indifference Reconciliation to Normal (VIRN) approved as part of a stipulation and agreement in Ameren Missouri's last gas rate case (File No. GR-2019-0077). Staff asserts its SRLE reconciles revenues above 400 kWh per

[168] Ex. 4, Richard Corrected Direct, Schedule SDR-9, page 5.
[169] Ex.104, Staff Class Cost of Service Report, page 3.

month per customer by creating a third residential block within Empire's billing system at this break point where usage from 401-600 kWh would be charged at the same rate as the first 400 kWh, but maintains Empire's exposure to changes in revenue below 400kWh per month per customer.[170]

127. Under Empire's proposed WNR, customers would not be able to know what they would be billed for energy prior to using that energy.[171] The WNR would not create a specific rate that is applicable to all customers; it would instead modify a customer's billable usage after that usage had been incurred.[172]

128. Empire's proposed WNR does not explicitly adjust for conservation.[173] Under the proposed WNR, all usage above a base usage would be considered to be weather sensitive usage.[174] Thus, its design would result in a customer who engaged in conservation efforts having to repay the Company for that customer's reductions in usage from year to year, as adjusted for the number of heating and cooling degree days.[175]

129. Staff contends that usage of approximately 400 kWh per customer per month appears unlikely to be impacted by either weather or conservation in the immediate future.[176]

130. Implementation of Staff's SRLE, or any rate stabilization mechanism for Empire, would be further complicated by large customers within the CB and SH class that would be more appropriately served under a different rate schedule.[177]

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[170] Ex.104, Staff Class Cost of Service Report, pages 3-5.
[171] Ex. 123, Stahlman Rebuttal CCOS, page 3.
[172] Ex. 123, Stahlman Rebuttal CCOS, page 3.
[173] Ex. 136, Lange Surrebuttal, page 5.
[174] Ex. 204, Mantle Rebuttal, page 5
[175] Ex. 160, Kliethermes Supplemental, page 2.
[176] Ex.104, Staff Class Cost of Service Report, page 4.
[177] Ex.104, Staff Class Cost of Service Report, page 10.

131. The SRLE would eliminate the throughput disincentive related to any energy efficiency programs implemented by Empire.[178]

132. Empire has earned a fair ROE without a WNR in recent periods.[179]

133. The Commission has previously approved a WNAR (the WNR counterpart for gas utilities, a Weather Normalization Adjustment Rider) for Liberty-Midstates Natural Gas division in Missouri.[180]

134. The weather normalization process for electric utilities is much more complex than for gas utilities, and WNARs for gas utilities are already complex, data intensive, and dependent on billing cycle stability.[181] In addition, Empire's proposed WNR is further complicated because it calls for customer specific rate adjustments, compared to the WNAR approved for Liberty-Midstates Natural Gas which has one rate applied to all customers in a class.[182]

135. Empire's proposed WNR is complicated and would likely confuse its customers.[183] Section 386.266.5 RSMo requires the WNR amount to be separately disclosed on each customer's bill. For customers to understand their bills they would have to understand the concept of heating and cooling degree days, and that "normal" weather used in the WNR charge is different than the normal weather on many websites.

136. Also, customers will be confused if the WNR charge for one month is different from the WNR charge for a different month yet the "difference from normal weather" is identical.[184]

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[178] Ex.104, Staff Class Cost of Service Report, page 12
[179] Ex. 203C, Mantle Direct, pages 4-5 and Ex. 204, Mantle Rebuttal, pages 2-3.
[180] Ex. 123, Stahlman Rebuttal CCOS, page 2.
[181] Ex. 160, Kliethermes Supplemental, page 2.
[182] Ex. 123, Stahlman Rebuttal CCOS, page 2.
[183] Ex. 204, Mantle Rebuttal, pages 4-5.
[184] Ex. 204, Mantle Rebuttal, page 5.

137. In addition to being unnecessarily complex, Empire's proposed WNR would be impossible to implement.[185]

138. Under Empire's proposed WNR if an additional person joined the household increasing household electrical usage, that additional usage would be normalized as if caused by weather.[186]

139. Empire has also not considered many technical aspects of its proposed WNR, including how or whether the WNR would be applied to estimated bills.[187]

140. Empire supports Staff's SRLE with four modifications: (1) adjust for the partial loss of new customer and sales revenues; (2) adjust for customer migration from CB or SH to GP; (3) implement the SRLE on a temporary basis; and (4) implement the SRLE on a calendar basis beginning January 1, 2020.[188]

141. Both Empire and Staff's weather normalization models are likely flawed. As many as 15 percent of Empire's residential customers received an estimated bill in 2018 and as many as 26 percent received an estimated bill in December 2019. Staff used a test period of August 2018 through July 2019 for weather normalization. The large percentage of estimated usage caused errors in both Staff's and the Company's weather normalization models.[189]

142. Additionally, both Staff's and Empire's weather analysis were impacted by a lack of data used to scale the daily weather adjustments to an overall revenue month.[190]

143. Staff's SRLE does not just compensate Empire for the rise and fall of revenue due to weather and conservation. The SRLE attributes any rise and fall of

[185] Ex. 123, Stahlman Rebuttal CCOS, page 2
[186] Ex. 204, Mantle Rebuttal, page 5.
[187] Ex. 204, Mantle Rebuttal, page 5.
[188] Ex. 29, Lyons Surrebuttal and True-Up, pages 5-6.
[189] Ex. 120, Kliethermes Rebuttal, pages 2-4; Ex. 160 Kliethermes Supplemental, pp. 2-3.
[190] Ex. 118, Stahlman Rebuttal, page 2.

revenue to weather or conservation, without considering the cause. The SRLE mechanism assumes a broad interpretation of conservation that includes any energy efficiency measures whether funded by ratepayers or not, as well as any other factor causing changes to the cost of energy sold. This unreasonably broad interpretation of "conservation" would include any customer decisions or actions that reduce or increase energy consumption.[191] For example, if a member of a household moved out causing a reduction in usage, the SRLE would attribute that reduction to conservation. Similarly, increases in residential class usage resulting from the current "stay at home" orders in many locations related to COVID-19 would also be attributed to conservation and eligible for SRLE adjustments.[192]

144. OPC believes that the SRLE is likely unlawful as the Commission has not previously promulgated a rule to implement the SRLE.[193] OPC suggests the Commission promulgate a rule to allow for implementation of a SRLE mechanism.[194]

## Conclusions of Law

G. Section 386.266.3 RSMo provides that any electrical corporation may make an application to the Commission to approve rate schedules authorizing periodic rate adjustments, outside of general rate proceedings, to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both.

[191] Ex. 160, Kliethermes Supplemental, page 4.
[192] Ex. 160, Kliethermes Supplemental, pages 7-8.
[193] Section 386.266.13 RSMo.
[194] EX. 204, Mantle Rebuttal, page 7.

H. Section 386.266.13 RSMo says that the Commission shall have previously promulgated rules to implement the application process for any rate adjustment mechanism under subsections 1 to 3 of this section prior to the commission issuing an order for any such rate adjustment.

**Decision**

Empire's proposed WNR is complex and would likely confuse customers as it is required to be disclosed separately on each customer's bill, is customer specific, and relies on a determination of normal weather that is not readily accessible. Because weather normalization models are data intensive and dependent on billing cycle stability, the large number of estimated bills in this case skews the results of both Staff's and Empire's weather normalization models. Because the weather modeling is inaccurate, there is potential for over or under-recovery, which is what the WNR is meant to avoid.

Further, the proposed WNR appears to be in violation of Section 386.266.3 RSMo, which requires "rate schedules". The WNR would not create a specific rate that is applicable to all customers under Empire's proposed WNR. Customers would not be able to know what they would be billed for energy prior to using that energy, but would instead have their billable usage modified after that usage had been incurred. The Commission finds that Empire's WNR should be rejected.

Staff contends the Commission's approval of a VIRN for Ameren Missouri in its last gas rate case is somehow supportive of approval of a SRLE in this case. However, that VIRN was approved as part of a settlement agreement and was based upon the facts specific to that case and the operations of the natural gas company in question. In this case, the Commission must analyze the SRLE as proposed in this case, based upon the facts presented in this case, and the operations of Empire.

Staff's SRLE proposal suffers from some of the same data problems as the WNR and does not comply with Section 386.266.3 RSMo. The large number of estimated bills and lack of billing data likely caused flaws in Staff's modeling. Additionally, Staff's proposed SRLE does not comply with Section 386.266.3 RSMo, because it would allow for adjustments due to the impact on revenues of increases or decreases in residential and commercial customer usage not exclusively due to variations in either weather, conservation, or both. While Empire's WNR does not directly account for conservation, Staff's proposed SRLE mechanism attributes any rise or fall of revenue to weather or conservation, regardless of the cause. Usage changes due to customers simply using less energy or customers moving in and out of Empire's service territory would be treated as resulting from conservation and weather. Staff's proposed SRLE is rejected.

Empire's proposed modifications to Staff's SRLE would not alleviate the billing data issues or bring it into compliance with Section 386.226.3 RSMo. Empire's proposed modified SRLE is rejected.

OPC argued it would be unlawful for the Commission to authorize a SRLE, either as proposed by Staff or Empire, based upon its interpretation of Section 386.266 RSMo as requiring the Commission to promulgate implementation rules prior to approving such a mechanism. Because the Commission has determined that both proposed WNR and SRLEs should be rejected on other grounds, a decision on this point is not necessary.

**5) FAC**

**Findings of Fact**

145. The Commission first authorized a Fuel Adjustment Clause (FAC) for Empire in its Report and Order in Empire's 2008 rate case (File No. ER-2008-0093) and

it has been continued with modifications in subsequent Empire rate cases.[195] Empire requested the continuation of its FAC pursuant to Section 386.266.1, RSMo.[196] To continue its FAC, Empire is required to file a new general electric rate case every four years.[197]

146. In this rate case, Empire seeks to continue its FAC with an updated base cost of energy. The difference between actually incurred fuel costs and the base fuel costs included in rates in this case will be billed or credited to each customer based on the customer's monthly energy usage.[198] The continuation of the FAC will permit Empire to adjust customers' bills twice each year, on June 1st and December 1st, based on the varying costs of fuel used to generate electricity at Empire's generating units and electric energy Empire purchases on behalf of its customers.[199]

147. Energy expenses represent a significant portion of the overall costs to operate an electric utility. Empire is mostly a price taker and not a price setter regarding variable energy costs.[200]

148. Empire's actual total energy costs continue to be relatively large, volatile, and beyond the control of the Company. [201]

149. Even if fuel analysts use production cost models to help calculate an FAC base factor, there are still many assumptions that have to be made, and it is difficult to model the marketplace due to the complex interactions of many factors including resource

[195] Ex. 101, Staff Direct Report, page 91.
[196] Ex. 4, Richard Corrected Direct, page 29.
[197] Section 386.266.5(3) RSMo.
[198] Ex. 4, Richard Corrected Direct, pages 30-31.
[199] Ex. 4, Richard Corrected Direct, pages 31-32, and Schedule SDR-11.
[200] Ex. 15, Tarter Rebuttal, page 5.
[201] Ex. 101, Staff Direct Report, page 95.

costs, unit outages and market prices. One of the primary reasons for having an FAC is that future FAC eligible costs cannot be predicted with certainty.[202]

150. The existing FAC base factor, that has been in effect since September 14, 2016, is $0.02415 per kWh.[203]

151. Empire initially requested that the FAC base factor be increased three percent to $0.02488 per kWh (inclusive of 100 percent recovery of transmission expenses).[204] Empire updated its requested FAC base factor (inclusive of 100 percent recovery of transmission expenses) to $0.02416 per kWh.[205]

152. Empire incurs Midcontinent Independent System Operator (MISO) transmission costs for 100 MWs of the Plum Point Power Plant in Arkansas. Empire owns a 50 MW share of that plant and has a purchased power contract for the capacity and generation of another 50 MW. Since the purchased power contract is for 50 percent of its total capacity of the Plum Point Power Plant, Empire is currently able to include 50 percent of its MISO costs in its FAC.[206]

153. Staff calculated Empire's percentage of Southwest Power Pool (SPP) transmission service costs at 32.04 percent with some exclusions,[207] which is near the 34 percent currently authorized by the Commission.

154. Empire's current FAC includes 50 percent of MISO non-administrative costs and 34 percent of SPP non-administrative costs. However, no transmission revenues are included in Empire's FAC.[208]

[202] Ex. 1011, Tarter Supplemental, page 8.
[203] Ex. 18, Doll Supplemental Direct, page 4; and Ex. 104, Staff Class Cost of Service, Appendix 2
[204] Ex. 14, Tarter Direct, pages 4-5.
[205] Ex. 18, Doll Supplemental Direct, page 4.
[206] Ex. 204, Mantle Rebuttal, pages 8, 12.
[207] Ex. 104, Staff's Class Cost of Service Report, page 39.
[208] Ex. 17, Doll Direct, page 7, and Schedule AJD-2, pages 4-5.

155. Those percentages were established in File Nos. ER-2014-0258 and ER-2014-035, and in Empire's most recent rate case, File No. ER-2016-0023, those same percentages were maintained.[209]

156. Empire proposes including 100 percent of transmission costs in the FAC base factor calculation. [210] Empire justifies the inclusion of all transmission costs by noting the time it has spent participating in working groups to ensure that customers have access to reliable cost effective energy, and claiming that those efforts have yielded adjusted production cost savings, lower resource adequacy requirements, and the ability to reliably accommodate lower cost generation delivery with increasing efficiency. SPP and MISO have been coordinating on seams efforts but they have completed no projects from that effort.[211]

157. The base factor in Empire's FAC should be set based on the base energy cost included in the revenue requirement set in this case.[212]

158. Empire's FAC tariff involves the accumulation of net energy costs over a six-month period and comparing that cost accumulation to the FAC base factor. Ninety-five percent of this over/under recovery balance is then credited/billed to Empire's customers over a six-month billing period that immediately follows the six-month accumulation period.[213]

159. Staff identified four accumulation periods that were under-recovered and three that were over-recovered.[214]

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[209] Ex. 17, Doll Direct, Schedule AJD-2, page 2.
[210] Ex. 15, Tarter Rebuttal, pages 7-8; and Ex. 17, Doll Direct, page 7.
[211] Ex. 17, Doll Direct, page 7 - 9.
[212] Ex. 101, Staff Direct Report, page 96.
[213] Ex. 4, Richard Corrected Direct, page 31.
[214] Ex. 161, Mastrogiannis Supplemental, page 3.

160. Staff recommends that the Commission continue to include the current percentages of MISO and SPP non-administrative costs, which are reflective of Empire's transmission costs associated with true purchased power and off-system sales, to be recovered in Empire's FAC.[215]

161. Staff recommends the Commission approve the continuation of Empire's FAC[216] using a trued-up base factor (inclusive of only transmission costs and revenues Empire incurs for Purchased Power and Off-System Sales) of $0.02333 per kWh.[217]

162. OPC supports keeping the percent of the transmission costs the same as in Empire's current FAC, but also asks to modify the FAC to include the transmission revenues associated with the applicable transmission costs as well. OPC contends that transmission costs and revenues should match the circumstances impacting the transmission costs and revenues when rates from this case become effective.[218]

163. The Commission has previously only approved appropriate transmission costs in the FAC in Empire's rate cases, along with Evergy Missouri West and Evergy Missouri Metro rate cases, and not transmission revenues.[219]

164. Changing the percentage of transmission costs and revenues Empire includes in its FAC is inconsistent with both prior Commission rulings and with the transmission percentage used by other Missouri investor-owned electric utilities with FACs.[220]

165. Empire's current sharing mechanism is a 95/5 ratio[221].

[215].Ex. Mastrogiannis Surrebuttal/True-up Direct, page 2
[216] Ex. 101, Staff Direct Report, page 92.
[217] Ex. 137, Mastrogiannis Surrebuttal True-Up Direct, page 2.
[218] Ex 203, Mantle Direct, page 16.
[219] Ex. 112, Mastrogiannis Rebuttal, page 4-5.
[220] Ex. 112, Mastrogiannis Rebuttal, page 3.
[221] Ex. 112, Mastrogiannis Rebuttal, page 2.



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166. Staff recommends continuing that sharing mechanism, where customers would be responsible for, or receive the benefit of, 95 percent of any change in fuel and purchased power costs as defined in the FAC tariff from the base amount included in rates. [222]

167. Empire is proposing to continue the current 95/5 sharing mechanism.[223]

168. OPC proposes changing the FAC sharing mechanism to an 85/15 ratio. OPC believes that a change of the sharing mechanism benefits the public interest by placing a greater incentive on Empire to manage its normalized fuel costs. OPC acknowledges that with an 85/15 sharing mechanism Empire would bear an increased risk, but argues Empire has the ability to influence FAC costs and the customers do not.[224]

169. The base fuel factor is only an estimate, and setting the base fuel factor in a rate case requires many assumptions and modeling challenges. Additionally, FAC eligible costs cannot be forecasted with certainty, which is one of the primary reasons for having a FAC in the first place.[225]

170. Over the last 11 years, OPC calculates that Empire has collected 99.9 percent of the FAC costs allocated to Missouri's customers, failing to collect less than $1.5 million of those costs.[226] Empire calculates that over a three-year period it collected about 99.6 percent of the actual FAC costs and had to absorb about $1.3 million of those costs. Over that same period if the sharing mechanism was 85/15 Empire states it would

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[222] Ex. 112, Mastrogiannis Rebuttal, pages 2-3.
[223] Ex. 14, Tarter Direct, page 3.
[224] Ex. 203, Mantle Direct, pages 7 and 12.
[225] Ex. 1011, Tarter Supplemental, page 8.
[226] Ex. 205, Mantle Surrebuttal, page 8.

have collected about 98.9 percent of the actual FAC costs and had to absorb almost $4 million of those costs..[227]

171. OPC argues that 85/15 was the appropriate sharing mechanism based upon Senate Bill 564 (now codified as Section 393.1400 RSMo.), which allows for an 85 percent recovery related to plant in service (PISA) depreciation.[228]

172. OPC states that the Legislature's selection of an 85 percent mechanism for PISA provides a more reasonable alternative to the 95/5 incentive mechanism previously adopted by the Commission for Empire's FAC.[229]

173. OPC also urges the Commission to change Empire's sharing ratio to 85/15 because of Empire's past hedging practices.[230] In File No. EO-2017-0065, a prudence review of Empire's FAC costs, OPC presented evidence that from the time Empire was granted a FAC through the filing of surrebuttal testimony in that case Empire's hedging policy resulted in losses of over $95 million.[231]

174. Hedging losses are a cost that flows through Empire's FAC for recovery from its customers.[232]

175. The Commission did not find Empire's hedging practices or losses were imprudent in File No. EO-2017-0065.[233] That decision was affirmed by the Missouri Court of Appeals in Case No. WD81627.[234]

[227] Ex. 15, Tarter Rebuttal, page 6.
[228] Ex. 203, Mantle Direct, page 13.
[229] Ex. 203, Mantle Direct, page 13.
[230] Ex. 205, Mantle Surrebuttal, page 4.
[231] Ex. 205, Mantle Surrebuttal, page 3.
[232] Ex. 205, Mantle Surrebuttal, page 3.
[233] Ex. 205, Mantle Surrebuttal, page 4-5.
[234] Ex. 17, Doll Direct, page 13.

176. In File No. EO-2017-0065, the Commission considered the value of hedging as analogous to the cost and value of buying earthquake insurance. The Commission stated: “The risk reduction offered by insurance has a value, although that value may not be fully realized until there is an earthquake, just as the value of hedging may not be fully realized until a combination of factors results in a price spike in the natural gas market.”[235]

177. After the prudence review in File No. EO-2017-0065 Empire changed its hedging policies.[236] Empire submitted an updated Energy Risk Management Policy dated December 20, 2019. Section four of the Energy Risk Management Policy regarding Empire’s hedging strategy has been streamlined and some of the advanced procurement methods have been eliminated.[237]

178. OPC speculates that Empire would have reduced hedging losses if it had been required to absorb 15 percent of the hedging losses,[238] but provides no evidentiary support that Empire would not have had the hedging losses with an 85/15 FAC sharing mechanism.

179. The FAC statute requires utilities to undergo prudency reviews every 18 months and refund imprudently incurred costs plus interest.[239]

180. Staff, through its review in this case, and previous reviews in Empire FAC prudence review cases has not found evidence that the current 95/5 sharing mechanism was inadequate and should be changed.[240]

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[235] File No. EO-2017-0065, Amended Report and Order, page 20, issued March 10, 2018.
[236] Ex.205, Mantle Surrebuttal, page 4-5.
[237] Ex. 215, Riley Rebuttal, page 3.
[238] Ex. 205, Mantle Surrebuttal, page 5.
[239] Section 386.266.5(4), RSMo.
[240] Ex. 112, Mastrogiannis Rebuttal, page 3.

181. Changing the FAC sharing percentage is inconsistent with both prior Commission rulings and with the transmission percentage used by other Missouri investor-owned electric utilities with FACs.[241]

182. Empire's current agreement with the Missouri Joint Municipal Electric Utility Commission (MJMEUC) is a 5-year agreement for Empire to sell energy and capacity to the cities of Monett, and Mount Vernon, Missouri.[242]

183. Empire's energy sold to MJMEUC under the agreement will be billed to the cities by MJMEUC resulting in a reduced portion of Empire's total fuel expense assigned and billed to Empire's retail customers. Empire will also sell energy back to the SPP on behalf of MJMEUC.[243]

184. Empire contends, and Staff's concurs, that the language describing the Off-System Sales Revenue (OSSR) portion of Empire's FAC tariff does not allow revenues from the MJMEUC contract, which is a full and partial requirement sales contract, to flow through the FAC, because the OSSR tariff language excludes revenue from full and partial requirement sales to municipalities.[244]

185. Empire was not opposed to modifying the FAC to allow revenue from the MJMEUC contract to flow through the FAC, so long as any such tariff modification is tethered to the establishment of an AAO or some other sort of vehicle that would allow Empire to create a regulatory asset for the difference in jurisdictional allocations as a result of the contract.[245]

[241] Ex. 112, Mastrogiannis Rebuttal, page2-3, and Schedule BM-r1
[242] Ex. 20, Doll Rebuttal, page 7.
[243] Ex. 20, Doll Rebuttal, pages 7-8.
[244] Ex. 137, Mastrogiannis Surrebutal True-Up direct, pages 3-4, and Ex. 20 Doll Rebuttal, pages 7-8.
[245] Ex. 20, Doll Rebuttal, page 8.

186. Staff was opposed to this modification of the AAO. However, Staff recommends that the Commission order Empire to file additional reporting requirements with its FAC monthly reports and Fuel Adjustment Rate filing workpapers. These additional reporting requirements will demonstrate that the energy purchased from Empire related to the MJMEUC contracts will be billed to the cities via MJMEUC and will thereby reduce a portion of the fuel expense that is allocated and billed to Empire's retail customers. This reduced portion of fuel expense will clearly illustrate that the energy purchased for these specific cities via MJMEUC is not flowing through the FAC in order to be collected from all Empire's retail customers.[246]

187. OPC agreed with the FAC language that has been in effect along with Empire's proposed changes in this case regarding revenues from MJMEUC contracts. OPC asks that the Commission require, as a part of Empire's monthly FAC filing, a detailed listing of the costs incurred due to the MJMEUC contract.[247]

188. OPC asked the Commission to prohibit Empire from passing short-term capacity contracts through the FAC by removing from its FAC tariff sheets its ability to recover any costs of capacity, regardless of the length of the contract. [248]

189. Staff has expressed concerns that the timing of the retirement of Asbury, the addition of a new capacity agreement with a customer, and the new generation resources not being available could lead to a SPP resource adequacy shortfall, which could require Empire to enter into potentially expensive short-term capacity contracts.[249]

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[246] Ex. 137, Mastrogiannis Surrebutal True-Up direct, page 4.
[247] Ex. 203, Mantle Direct, page 3.
[248] Ex. 205, Mantle Surrebuttal, page 20.
[249] Ex. 111, Luebbert Rebuttal, page 3.

## Conclusions of Law

I. The Commission may approve rate schedules for an FAC and may include "features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities".[250]

J. Commission Rule 20 CSR 4240-3.161(3) establishes minimum filing requirements for an electric utility that wishes to continue its fuel adjustment clause in a rate case subsequent to the rate case in which the fuel adjustment clause was established. Empire has met those filing requirements.

K. FACs are subject to prudence reviews at least every eighteen-months, requiring a refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate.[251]

L. Utilities with an FAC are required to file a general rate case with a new rates effective date no later than four years after the effective date of the Commission's order implementing the FAC.[252]

M. Only transmission costs associated with prudently incurred fuel and purchased-power costs may be flowed through an FAC between rate cases.[253]

N. Section 393.1400 RSMo, which includes a provision allowing plant in-service accounting, allows 85 percent of the depreciation expense and return to be included for recovery in the electric utility's rate base in its next general rate case.

[250] Section 386.266.1, RSMo.
[251] Section 386.266.5(4), RSMo.
[252] Section 386.266.5(3), RSMo.
[253] Section 386.266.1, RSMo.

O. Under Section 386.266.5, RSMo, the Commission cannot revise Empire's FAC without considering all relevant factors, that may affect the costs or overall rates and charges of the corporation.

## **Decision**

Empire has requested to continue its FAC with an updated base cost of energy, to continue the current 95/5 sharing mechanism, and to modify its current FAC to include 100 percent of transmission costs in the FAC base factor calculation. Because Empire's actual total energy costs continue to be relatively large, volatile, and beyond the control of the Company, the Commission will approve continuation of its FAC.

As to the appropriate sharing mechanism, OPC has proposed changing the FAC incentive ratio for Empire from 95/5 to 85/15. OPC argues that changing the sharing percentages to 85/15 will provide more incentive for Empire to keep net fuel costs as low as possible. Staff and Empire argue that the current sharing mechanism has not been shown to be ineffective and should stay the same. The state legislature gave the Commission the discretion to create the FAC incentives and it is within the Commission's discretion to reevaluate that sharing mechanism. The facts in this case, however, do not show that there is any reason to adjust the sharing mechanism.

The Commission has found on several occasions, and finds here that the 95/5 sharing ratio provides Empire sufficient incentive to operate at optimal efficiency and still provides an opportunity for Empire to earn a fair return on its investment. The evidence in this case also showed that Empire continues to operate efficiently. Staff's witness testified that the 95/5 ratio was an appropriate incentive based on finding no pattern of imprudence during the previous FAC prudence reviews. Additionally, no evidence was presented that Empire acted imprudently or manipulated its FAC to the detriment of ratepayers. OPC's evidence showed changing the sharing mechanism to 85/15 would provide more pressure on Empire, but not that more pressure is needed. Therefore, the Commission determines that based on the facts in this case, the 95/5 sharing mechanism in Empire's FAC provides the appropriate incentive to properly manage its net energy costs.

OPC's claim that the legislature has provided guidance on the appropriate incentive mechanism sharing percentages by including 15 percent of capital investments in the PISA statute is also not persuasive. The legislature's creation of an unrelated sharing mechanism in another utility statute does not imply the legislature intends those percentages to carry over to the FAC.

The Commission's decision in this case should not be taken as stating that there may never be a change to the sharing percentage or that the Commission will always maintain the status quo. However, in this case the evidence does not support a change in the sharing percentage.

Regarding transmission costs, the Commission is not changing the costs that flow through the FAC. The percentage of transmission costs included in the FAC will remain the same as they are now, which is 34 percent for SPP costs, 50 percent for MISO transmission costs, and no allowance for transmission revenues. This is consistent with Missouri law and prior Commission rulings, which allow only transportation costs related to purchased power to flow through the FAC.

The Commission finds that Staff's trued-up base factor calculation of $0.02333 per kWh, which incorporates the appropriate percentages of SPP and MISO non-administrative transmission costs, is the appropriate base factor for Empire's FAC.

The Commission disagrees with OPC's contention that revenue from the MJMEUC contract should flow through Empire's FAC. Empire's current FAC tariff language does not allow revenues from its MJMEUC contract to flow through its FAC. The Commission further finds that the FAC tariff should not be revised to allow revenue from MJMEUC contracts to flow through the FAC.

OPC alternately recommended that Empire be required, as a part of its monthly FAC filing, to provide a detailed listing of the costs incurred due to the MJMEUC contract. The Commission finds OPC's request to be reasonable. The Commission will order additional reporting for Empire to file with its FAC monthly reports and Fuel Adjustment Rate filing workpapers, including a detailed listing of all costs incurred due to the MJMEUC contracts and the revenues that Empire receives from MJMEUC.

Additionally, OPC's recommendation that Empire's FAC be modified to prohibit inclusion of any capacity contracts is not appropriate. There has been no demonstration that Empire will be unable to meet SPP resource adequacy requirements. Any concerns about the appropriateness of short-term capacity cost can be reviewed as part of the FAC prudency review, and the Commission will direct its Staff to do so. Thus, the Commission finds no reason to change Empire's FAC to disallow the pass through of short-term capacity costs.

**6) Credit Card Fees**

**Findings of Fact**

190. Currently, each Empire customer who pays their utility bill with a credit card is charged a transaction fee.[254] The fee is $2.25 per residential payment and is imposed by a third party that processes the card payments.[255]

[254] Ex. 101, Staff Direct Report, page 82.
[255] Ex. 101, Staff Direct Report, page 103 and Ex. 1, Baker Direct, page 9.

191. For Empire, payment of bills by credit card has increased 36 percent in the last two years from 379,329 transactions in 2016 to 511,195 in 2018.[256] Payment by credit card is the second most utilized payment option for Empire customers,[257] with 25 percent of Empire's customers paying with credit or debit cards.[258]

192. Empire proposes the elimination of credit card convenience fees for individual customers, with Empire instead recovering the costs associated with processing online card payments in its overall cost of service.[259]

193. The fees associated with credit card transactions are similar to bank fees Empire incurs that are already included in the cost of service paid by all customers.[260]

194. Empire has not projected the number of customers that may pay bills by credit card if no convenience fee is charged to them, but based on current participation, Staff anticipates that the total number of customers paying with credit cards will increase if there is no convenience fee.[261]

195. Empire states that it is important from a customer service perspective to provide its customers the choice to pay online, reducing the amount of customer service representative hours needed to receive and process in-person payments from customers.[262]

196. If the Commission approves including credit card fees in Empire's revenue requirement, Staff recommends that the Company be ordered to:[263]

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[256] Ex. 1, Baker Direct, page 9.
[257] Ex. 101, Staff Direct Report, page 104.
[258] Ex. 200, Conner Direct, page 9.
[259] Ex. 2, Baker Rebuttal, page 3.
[260] Ex. 1, Baker Direct, page 10.
[261] Ex. 101, Staff Direct Report, page 104.
[262] Ex. 1, Baker Direct, page 10.
[263] Ex. 101, Staff Direct Report, page 105

a. Track performance and savings to the Company and its customers from this initiative.

b. Monitor the level of customers using the credit card option, whether the number of payments by credit card increases, and whether eliminating a fee to pay by credit card results in savings to the customer and/or to the Company.

c. State how the Company will inform customers that there is no fee to pay their bill by credit card.

197. The Commission has previously approved requests to eliminate credit card convenience fees with the utility absorbing credit card processing services in the cost of service.[264]

198. OPC opposes the elimination of credit card fees. If all Empire's customers are required to pay for credit card fees, they will not only be paying for their own payment method, but also for those who choose to pay with credit or debit cards.[265] OPC asserts that the 25 percent of Empire's customers who are using credit cards to pay their electric bills will receive a net economic benefit, to the detriment of Empire's customers who cannot use a credit card to pay their electric bills.[266]

199. Empire proposes that $1,297,266 be included in rates for credit card processing fees based on the true-up period.[267]

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[264] Ex. 101, Staff Direct Report, page 105, referencing File Nos. GR-2017-0215 & GR-2017-0216.
[265] Ex. 200, Conner Direct, page 9.
[266] Ex. 201, Conner Rebuttal, page 3.
[267] Ex. 7, Richard True-Up Direct, page13.

200. Staff proposes that $1,165,283 be included in rates for credit card fees based on the test period.[268] This amount is based on Staff's jurisdictional allocation factor of 89.09 percent applied to costs booked in Account 903, including credit card fees.[269]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

The 36 percent increase in the use of credit card payments in just the last two years illustrates that more customers want to pay their utility bills online using a credit or debit card. As bank fees are already recovered in the cost of service, credit card transaction fees should be similarly treated. OPC's argument that 75 percent of Empire's customers who do not use credit cards will pay for the 25 percent who do is not persuasive given that the number of payments by credit card are increasing and the elimination of the credit card transaction fee effectively removes a barrier to more customers paying by credit card. The Commission finds that credit card fees should be included in the Company's revenue requirement so that individual fees are no longer required.

The Commission finds that the appropriate amount of credit card fees to include in Empire's revenue requirement is $1,165,283 based on the test year period.

The Commission additionally finds it reasonable to order Empire to perform the following tasks: (1) track performance and savings to the Company and its customers from this initiative; (2) monitor the level of customers using the credit card option, whether the number of payments by credit card increases, and whether eliminating a fee to pay

[268] Ex. 148, Bolin Additional Evidence.
[269] Ex. 129, Bolin Surrebuttal True-Up, page 5 and Ex. 148, Bolin Additional Evidence.

by credit card results in savings to the customer, to the Company, or to both; and (3) state how the Company will inform customers that there is no fee to pay their bill by credit card.

**7) Rate Case Expense**

**Findings of Fact**

201. Rate case expense is defined as all incremental costs incurred by a utility directly related to an application to change its general rate levels. These applications are usually initiated by the utility, but rate case expenses may also be incurred as a result of the filing of an earnings complaint case by another party. The largest amounts of rate case expenses usually consist of costs associated with use of outside witnesses, consultants, and external attorneys hired by the utility to participate in the rate case process.[270]

202. OPC recommends allowable rate case expenses be normalized over three years, because Empire generally files rate cases every three years.[271]

203. Staff recommends allowable discretionary rate case expenses be normalized over two years.[272]

204. Empire proposes including an annualized amount of prudent rate case expense and amortizing it over a period of two years.[273]

205. Empire has incurred expenses for outside consultants in this rate case.[274]

206. Empire is required to submit a depreciation study every five years. Empire submitted a depreciation study in File No. ER-2016-0023, Empire's last rate case, which

[270] Ex. 101, Staff Direct Report, page 74.
[271] Ex. 200, Conner Direct, page 6.
[272] Ex. 101, Staff Direct Report, page 73.
[273] Ex. 7, Richard True-Up Direct, pp. 13, 16-17; and Ex. 59 Rate Case Expense Workpaper of Sheri Richard.
[274] Ex. 101, Staff Direct Report, page 73.

is within five years of this rate case.[275] It is appropriate to include a normalized amount, one-fifth of the study cost, in rate case expense in this case.[276]

207. Empire must perform a line loss study at least every four years. Empire performed a line loss study in 2018, which is within four years of this rate case.[277] It is appropriate to include a normalized amount, one-fourth of the study cost, in rate case expense in this case.[278] Neither OPC nor Empire oppose a four-year normalization for the line loss study.[279]

208. Staff recommends assigning Empire's discretionary rate case expenses to both ratepayers and shareholders based upon a 50/50 split, full recovery of the depreciation study over five years, and full recovery of the line loss study over four years.[280] Staff calculated $71,676 in trued-up rate case expense normalized over two years.[281]

209. Rate case expense can benefit both ratepayers and shareholders. Through a rate case, the ratepayer is receiving the opportunity to be provided safe and adequate service at a just and reasonable rate and the shareholder is receiving an opportunity to receive an adequate return on investment.[282]

210. Rate case expense sharing creates an incentive and eliminates a disincentive on the utility's part to control rate case expenses to reasonable levels.[283]

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[275] Ex. 101, Staff Direct Report, page 73.
[276] Ex. 140, Niemeier Surrebuttal/True-Up, pages 8-9.
[277] Ex. 140, Niemeier Surrebuttal/True-up, page 9.
[278] Ex. 140, Niemeier Surrebuttal/True-up, page 9.
[279] Ex. 201, Connor Rebuttal, page 2, and Ex. 6, Richars Surrebuttal, page 7.
[280] Ex. 101, Staff Direct Report, page 74.
[281] Ex. 156, Bolin Supplemental, page 4 and Ex. 140, Niemeier Surrebuttal True-Up, pages 8-9.
[282] Ex. 101, Staff Direct Report, page 74.
[283] Ex. 101, Staff Direct Report, page 74.

211. Utility management has a high degree of control over rate case expense. Generally, the utility determines when, and how often, a rate case is filed. Attorneys, consultants, and other services can either be provided by in-house personnel or can be acquired from an outside party. Rate case expenses subject to a sharing mechanism do not include internal labor costs. Those are included in the cost of service through the payroll and are paid by ratepayers.[284]

212. Empire says that applying a sharing mechanism to all consultant costs is inappropriate because it does not have an in-house rate design or cost of service department and must contract out for these services. Larger utilities have those in-house services and may recover those costs through rates.[285]

213. Empire argues that the filing of this rate case was not discretionary. According to Section 386.266.5(3), RSMo, Empire had to file a rate case with the effective date of new rates to be no later than four years after the effective date of the Commission order implementing its FAC, September 9, 2016.[286]

214. A FAC is a voluntary mechanism that Empire chose to request and chooses to seek continuation of in this case.[287]

215. Empire also argues that the concept of sharing rate case expense with shareholders is incorrect. Empire asserts that rate case expense is a cost of supplying service to its customers and therefore should be included in its cost of service.[288]

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[284] Ex. 101, Staff Direct Report, page 74.
[285] Ex. 5, Richard Rebuttal, page 34.
[286] Ex. 5, Richard Rebuttal, page 33-34.
[287] Ex. 129, Bolin Surrebuttal/True-up, pages 5-6
[288] Ex. 5, Richard Rebuttal, page 34.

216. Not all rate case expense is a necessary cost of supplying service to customers. Some rate case expense produces direct benefits to shareholders that are not shared with customers, such as hiring an outside technical expert seeking a higher ROE.[289]

217. Empire's shareholders stood to benefit from many of the issues raised and litigated by Empire in this case. In this case, Empire has requested a rate of return of 9.95 percent,[290] the continuation of its FAC,[291] elimination of credit card transaction fees,[292] a weather normalization mechanism[293], LED lighting trackers,[294] inclusion of various incentive compensation packages,[295] and other items that Empire wants included in its cost of service.

## Conclusions of Law

P. The Commission has broad discretion to determine which expenses a utility may recover from ratepayers. The Missouri Supreme Court has stated that the Commission's statutory power and authority to set rates "necessarily includes the power and authority to determine what items are properly includable in a utility's operating expenses and to determine and decide what treatment should be accorded such expense items."[296] The Commission's authority extends to allocating an expense between certain

[289] Ex. 129 Bolin Surrebuttal/True-up, pages 6-7.
[290] Ex. 36, Hevert Direct, page 2.
[291] Ex. 26, Lyons Direct, page 5.
[292] Ex. 2, Baker Rebuttal, page 3.
[293] Ex. 22, Fox Direct.
[294] Ex. 33, McGarah Direct.
[295] Ex. 5, Richard Rebuttal, pages 24-29.
[296] *State ex rel. City of W. Plains v. Pub. Serv. Comm'n*, 310 S.W.2d 925, 928 (Mo. 1958). See also, *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d 153, 166 (Mo. App. 2013).

classes or groups of ratepayers[297] and to requiring company shareholders to bear expenses the Commission finds to be unreasonable or unnecessary.[298]

Q. Subsection 20 CSR 4240-3.160(1)(A) requires that a depreciation study be submitted with a general rate increase request unless Staff received these items during the three years prior to the rate increase request or before five years have elapsed since last receiving said items.

R. To be able to continue or modify a rate adjustment mechanism, such as an FAC, 20 CSR 4240-20.090 (13)(B) requires a utility to have conducted a new line loss study. The end of the twelve month period of actual data collected for use in that study must be no earlier than four years before the date the utility files the general rate proceeding seeking to continue or modify that rate adjustment mechanism.

S. To be able to continue utilizing an FAC, Subsection 386.266.5(3), RSMo requires Empire to "file a general rate case with the effective date of new rates to be no later than four years after the effective date" of the Commission's order implementing a FAC for Empire. Empire's last request for an overall increase in rates for electric service was docketed as File No. ER-2016-0023 and the Commission order authorizing the continuation of Empire's current FAC was effective September 9, 2016. A FAC is a voluntary mechanism.[299]

T. The Commission has previously found rate case expense sharing was just and reasonable. In a 1986 decision, *In the Matter of Arkansas Power and Light Company*, the Commission adopted Public Counsel's proposed disallowance of one-half of rate case

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[297] *State ex rel. City of W. Plains v. Pub. Serv. Comm'n*, 310 S.W.2d at 934.
[298] *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d at 164-165.
[299] *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d at 164-165.

expense.[300] The Commission also acknowledged this authority in a number of other cases.[301]

U. The Commission has the legal authority to apportion rate case expense between ratepayers and shareholders. In File No. ER-2014-0370, involving Kansas City Power and Light Company's request for a rate increase the Commission determined that rate case expense should be shared between the ratepayers and shareholders.[302] That decision was upheld by the Western District Court of Appeals, which found that "the remedy crafted by the [Commission] was a reasonable exercise of the [Commission's] discretion and expertise in determining just and reasonable expenses to be borne by ratepayers."[303]

**Decision**

In many ways rate case expense is like other common operational expenses that a utility must incur to provide utility services to customers. Since customers benefit from having just and reasonable rates, it is appropriate for customers to bear some portion of the utility's cost of prosecuting a rate case. However, rate case expense is also different from most other types of utility operational expenses in that 1) the rate case process is adversarial in nature, with the utility on one side and its customers on the other; 2) rate case expense produces some direct benefits to shareholders that are not shared with customers, such as seeking a higher ROE; 3) requiring all rate case expense to be paid

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[300] Report and Order, File No. ER-85-265, 28 Mo. P.S.C. (N.S.) 435, 447 (1986),

[301] See, *In the Matter of Kansas City Power & Light Company,* Report and Order, File Nos. EO-85-185 and EO-85-224, 28 Mo. P.S.C. (N.S.) 229, 263 (1986), and *In the Matter of Missouri Gas Energy,* Report and Order, File No. GR-2009-0355, 19 Mo. P.S.C. 3d 245, 303 (2010).

[302] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Report and Order, File No. ER-2014-0370, issued September 2, 2015.

[303] *In Matter of Kansas City Power & Light Co.'s Request for Auth. to Implement a Gen. Rate Increase for Elec. Serv. v. Missouri Pub. Serv. Comm'n*, 509 S.W.3d 757, 779 (Mo. Ct. App. 2016), reh'g and/or transfer denied (Nov. 1, 2016), transfer denied (Feb. 28, 2017).

by ratepayers provides the utility with an inequitable financial advantage over other case participants; and 4) full reimbursement of all rate case expense does nothing to encourage reasonable levels of cost containment.[304]

The evidence shows that Empire's shareholders stood to benefit from many of the issues raised and litigated by Empire in this case. In this case, Empire has requested a rate of return of 9.95 percent, the continuation of its FAC, elimination of credit card transaction fees, a weather normalization mechanism, LED lighting trackers, inclusion of various incentive compensation packages, and other items that Empire wants included in its cost of service. It was Empire's decision and entirely within Empire's power to pursue these issues, hire outside consultants to support issues, and to file this rate case.

Empire also argues that there should be no rate case expense sharing because Empire was required to file a rate case pursuant to Section 386.266.5(3), RSMo. This is a requirement tied to the implementation and continuation of Empire's FAC and the FAC is a risk management mechanism that primarily benefits Empire. Empire knew when it requested a FAC that it would have to file a rate case in four years.

Therefore, it is just and reasonable that the shareholders and the ratepayers, who both benefited from the rate case, share in the rate case expense. The Commission finds that in order to set just and reasonable rates under the facts in this case, the Commission will require Empire's shareholders to cover a portion of Empire's rate case expense. The Commission will assign Empire's discretionary rate case expense to both ratepayers and shareholders based upon a 50/50 split.

The Commission finds Staff's recommendation to normalize discretionary rate case expense over two years to be appropriate. Empire's proposal to amortize rate case

[304] Amended Report and Order, File No. GR-2017-0215, page 52, issued March 7, 2018.

expense would be treating it differently than other classes of expenses. OPC's recommendation of a three year normalization is inappropriate given Empire's intention to file its next rate case within a year.

Because conducting a depreciation study and line loss study are required by Commission rule, it is appropriate that ratepayers bare their full cost. However, since they are not required to be performed annually, it is not appropriate to include their full cost in rates in this case. The Commission finds that Empire should be allowed full recovery of the depreciation study over five years and full recovery of the line loss study over four years, because that is the period set out in the rule for their frequency.

The Commission determines that the appropriate amount of rate case expenses to include in Empire's revenue requirement is $71,676 annually, for two years. That amount includes the normalized cost of the depreciation study from the prior rate case, and the normalized cost of the line loss study.

### 8) Management expense

### Findings of Fact

218. OPC asks the Commission to disallow officer ($34,618) and management ($3,673,266) expenses for Empire for a total amount of $3,707,884, through the test year period. [305]

219. OPC states that Empire lacks formal policies and procedures regarding travel expenses, and these amounts should be removed to protect ratepayers from reimbursing Empire for expenses that do not help the company provide safe and adequate service to its customers. OPC calculated disallowances for local meals,

[305] Ex. 202, Conner Surrebuttal True-Up, page 4.

excessive charges for travel, and gifts and celebrations for the company and employees.[306]

220. Among other officer expense charges that OPC identified as being partially allocated to Empire's rate payers are trips to Bermuda ($904.32), Australia ($268.77), and London and Peru ($2,268.09) totaling $3,441.17.[307] Empire states that the Bermuda trip was never allocated to Empire or included in its cost of service.[308]

221. OPC differentiated between officer expenses and management expenses and between meals and other officer expenses. While OPC reviewed officer expense account charges, it did not review any manager expenses. OPC simply applied its percentage disallowance of officer meals and other expenses to management expense charges without any review of manager expense account charges.[309] OPC's disallowance of other officer expenses at the end of the test year was $31,914 of which $904 were related to the Bermuda trip.[310]These disallowances were for officer expense account charges that included excessive meal charges, alcohol, gifts, celebrations, unsupported expense claims and other charges that do not provide benefits to Empire rate payers.[311]

222. OPC disallowed $2,704 in officer meals through the test year.[312] Lunchtime may be the only time available for some internal meetings, and most of the people attending those meetings are not paid for the additional hours. Providing a meal incentivizes attendance and allows for additional productive time.[313]

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[306] Ex. 200, Conner Direct, page 8.
[307] Ex. 299, Conner Supplemental testimony, page 4.
[308] Ex. 1018, Richard Responsive Supplemental, page 7.
[309] Ex. 299-7, Conner Testimony in Response to Commission Questions, page 4.
[310] Ex. 202, Conner Surrebuttal, ACC-S-1.
[311] Ex. 200, Conner Direct, page 7.
[312] Ex. 202, Conner Surrebuttal, ACC-S-1.
[313] Ex. 5, Richard Rebuttal, page 30.

### Conclusions of Law

No additional Conclusions of Law are required for this issue.

### Decision

Some management expenses that do not benefit ratepayers should be disallowed. Empire's justifications for providing meals to compensate for unpaid hours and incentivize attendance seems reasonable. The Commission finds that other officer expenses for trips to Australia, London, and Peru should be disallowed as they have no reasonable connection to providing safe and adequate service to ratepayers. Since the Bermuda trip was not included in Empire's cost of service, no adjustment is necessary. The additional other officer expense disallowances recommended by OPC also appear reasonable in that the charges provide no benefits to ratepayers.

The Commission does not find credible OPC's contention that if an average amount of corporate officer expenses are found to be excessive and should be disallowed that an identical percentage of all lower level manager expenses should be assumed to also be excessive. An analysis of at least a sample of management expense reports would be necessary to support any relationship of application of officer expense disallowance percentages to management. Therefore, the Commission disallows $31,010 of other officer expense charges and allows the remaining $3,676,874 to be recovered in Empire's cost of service.

## 9) Allowance for Funds Used During Construction

### Findings of Fact

223. On June 1, 2018, Empire borrowed $90 million from LUCo to refinance Empire's $90 million of first mortgage bonds. The terms of Empire's $90 million

promissory note were a 15-year term at a 4.53 percent interest rate and a $450,000 origination fee along with a "make whole" provision.[314]

224. LUCo drew $90 million from its credit facility under short-term conditions in order to lend Empire $90 million.[315]

225. LUCo was not charged a $450,000 origination fee as part of issuing the $90 million from its credit facility. Hence, LUCo charged Empire for issuance costs for long-term debt that was never issued but were instead borrowed from the LUCo credit facility.[316]

226. Empire did not solicit any bids for the refinancing of the $90 million first mortgage bond. Instead LUCo based the rate for this promissory note upon the most recent competitively bid private long-term debt placement by a LUCo affiliate, Liberty Utilities' Finance GP1 (LUF), in March 2017.[317]

227. On March 24, 2017, LUF (LUCo's debt financing platform) issued $750 million of Series E debt, which consisted of six tranches[318]:

a. Tranche 1- $100 million (3-year maturity, 2.78 percent coupon),
b. Tranche 2 - $80 million (5-year maturity, 3.30 percent coupon),
c. Tranche 3 - $70 million (7-year maturity, 3.69 percent coupon),
d. Tranche 4 - $250 million (10-year maturity, 3.94 percent coupon),
e. Tranche 5 - $21 million (20-year maturity, 4.54 percent coupon), and
f. Tranche 6 - $229 million (30-year maturity, 4.89 percent coupon).

[314] Ex. 220, Schallenberg Direct, page 12.
[315] Ex. 220, Schallenberg Direct, page 14, and Ex. 43, Timpe Rebuttal, page 3.
[316] Ex. 220, Schallenberg Direct, page 15.
[317] Ex. 129, Bolin Surrebuttal True-Up, page11.
[318] Ex.299-17, OPC Reply to Testimony Responding to Commission Questions of David Murray, page 3

228. The weighted average cost of the six tranches was 4.00 percent and the weighted average maturity was 14.75 years. If Empire had been assigned an implied 15-year tenor based on March 24, 2017 debt, the cost of this debt, which would have been based on applying 50 percent weight to Tranche 4 and 50 percent weight to Tranche 5, would be 4.24 percent.[319]

229. Empire states that there was a need to replace maturing long-term debt with new long-term debt and that LUCo's financing approach allows all of its subsidiaries to benefit from access to a larger pool of potential lenders.[320]

230. Empire stresses that refinancing $90 million of maturing long-term bonds with short-term debt violates basic principles of financing which seek to match the term of borrowing with the expected life of the asset and its cash flow recovery. Empire states that short-term borrowing such as commercial paper carries a lower interest rate than long-term borrowing, but there are additional risks and interest rate volatility.[321]

231. Staff's assessment indicated that with Empire's current credit rating it could have obtained long-term debt at 3.4 percent, which is lower than the 4.53 percent LUCo is charging Empire.[322] However, there is no objective way to estimate what Empire's cost of debt may have been without competitive bidding because it no longer directly issues debt to third-party investors.[323]

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[319] Ex. 299-17, OPC Reply to Testimony Responding to Commission Questions of David Murray, page 3.
[320] Ex. 44, Cochrane Surrebuttal, pages 8-9.
[321] Ex. 44, Cochrane Surrebuttal, page 11.
[322] Ex. 130, Chari Surrebuttal, page 11, and Ex. 156, Bolin Supplemental, page 6.
[323] Ex. 210, Murray Direct, page 8.

232. Under the Commission's applicable Affiliate Transactions Rule, Empire should not be charged more than the fully distributed cost or fair market value, whichever is less. [324]

233. The average cost of LUCo's short-term debt for the 12-month period ending January 31, 2020, is 2.15 percent.[325]

234. Short-term debt is usually a component of a utility's capital structure. However, if it is fully supporting construction work in progress (CWIP), then it is typically excluded from the rate making capital structure, and, instead, is reflected in the Allowance for Funds used During Construction (AFUDC) rate.[326]

235. AFUDC rate includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.[327]

236. The formula and inputs for calculating the AFUDC rate are[328]:

$$Ai = s(S/W) + d(D/D + P + C)(1-S/W)$$

$$Ae = [1-S/W][p(P/D+P+C)+c(C/D+P+C)]$$

Ai = Gross allowance for borrowed funds used during construction rate.
Ae = Allowance for other funds used during construction rate.
S = Average short-term debt.
s = Short-term debt interest rate.
D = Long-term debt.
d = Long-term debt interest rate.
P = Preferred stock.
p = Preferred stock cost rate.
C = Common equity.
c = Common equity cost rate.

[324] Ex. 211, Murray Rebuttal page 9.
[325] Ex. 156, Bolin Supplemental, page 5.
[326] Ex. 210, Murray Direct, page 5.
[327] Ex. 60, Electric Plant Instructions.
[328] Ex. 60, Electric Plant Instructions.

W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs related to plant under construction.

237. Empire's position is the AFUDC rate must be calculated based on the "actual book value", as prescribed in the FERC Uniform System of Account (USOA), which is outlined in Electronic Code of Federal Regulations: Title 18, Chapter 1, Subchapter C, Part 101.[329]

238. The USOA formula is logical and reasonable for companies financially managed as stand-alone companies because their capital structures are actively managed for purposes of maintaining reasonable capital balances, which includes the use of short-term debt as bridge financing to fund CWIP.[330]

239. Empire is no longer financially managed as a stand-alone entity, so the dividend payout ratio is different. Over the last two quarters, Empire has retained all of its earnings rather than distributing dividends to LUCo. This distorts how AFUDC is determined.[331]

240. If Empire would have still paid the dividends to outside shareholders, it would be required to issue short-term debt to help fund its capital expenditures. This would result in a lower capitalization rate for purposes of determining AFUDC.[332]

241. OPC supports either funding all of Empire's CWIP at the short-term debt rate or including the short-term debt in the Rate of Return.[333]

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[329] Ex. 60, Electric Plant Instructions; and Empire's Statement of Position, page 13.
[330] Ex. 210, Murray Direct, page 15, lines 15-16.
[331] Ex. 210, Murray Direct, page 15.
[332] Ex. 210, Murray Direct, page 15.
[333] Ex. 210, Murray Direct, page 15.

242. OPC also supports removing the $450,000 origination fee and excess interest rate from Empire's $90 million promissory note from rate base; however, there is no direct testimony to support this.

## **Conclusions of Law**

V. Commission Rule 20 CSR 4240-20.015 (1)(B) defines an affiliate transaction as:

> Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, …

W. Commission Rule 20 CSR 4240-20.015 (2)(A) States that:

> A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if—
>
> 1. It compensates an affiliated entity for goods or services above the lesser of—
>     A. The fair market price; or
>     B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or
>
> 2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of—
>     A. The fair market price; or
>     B. The fully distributed cost to the regulated electrical corporation.

X. Commission Rule 20 CSR 4240-20.015 (2)(B) states that:

> Except as necessary to provide corporate support functions, the regulated electrical corporation shall conduct its business in such a way as not to provide any preferential service, information or treatment to an affiliated entity over another party at any time.

Y. Commission Rule 20 CSR 4240-20.015 (3)(A) sets forth evidentiary standards for affiliate transactions :

> When a regulated electrical corporation purchases information, assets, goods or services from an affiliated entity, the regulated electrical corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate.



ACC-D-3

Z. The Commission's affiliate transaction regulations require that Empire utilize a Cost Allocation Manual (CAM) with regard to its transactions with affiliated companies.[334]

AA. In File No. EM-2016-0213, the Commission approved a stipulation and agreement in which the joint applicants agree they would not obtain Empire financing services from an affiliate, unless such services comply with Missouri's Affiliate Transaction Rules.

BB. The presumption of prudence does not apply to affiliate transactions. The affiliate transaction rules were enacted in an effort to prevent regulated utilities from subsidizing their non-regulated activities. To presume that a regulated utility's costs in a transaction with an affiliate were incurred prudently is inconsistent with these rules.[335]

**Decision**

The Commission finds the $90 million promissory note does not comply with the Commission's Affiliate Transactions Rules. By refinancing the first mortgage bonds at a higher rate of interest than the short-term debt rate of its source, LUCo received a financial advantage. Empire executed a 15-year promissory note with LUCo at an interest rate of 4.53 percent and with a $450,000 origination fee and "make whole" provision. There is no way to determine what the market interest rate would have been had Empire issued long term debt, because there were no competitive bids to determine market value. However, in financing the $90 million through its credit facility, LUCo incurred a lower rate of debt than what it charged Empire and no origination fee. Therefore Empire did not pay the fully distributed cost for the loan given that there were no competitive bids to determine

[334] 20 CSR 4240-20.015.2(E) and .3(D).
[335] *Office of the Public Counsel v Mo.PSC* 409 S.W.3d 371 (Mo. 2013).

the market value. Given the Commission's decision on the appropriate capital structure in issue one, the $90 million loan will not impact the revenue requirement through the Rate of Return.

In addition, the Commission finds credible evidence that the $90 million does impact the rate base through the AFUDC calculation. Therefore, for the purpose of the AFUDC calculation, the $90 million note should be treated as short-term debt. The Commission finds that the appropriate cost of debt for Empire's $90 million note should have been 2.15 percent and not 4.53 percent. The Commission does not find Empire's argument persuasive that the AFUDC calculation should be based on the "actual book balances" in situations where Empire's financing was not in compliance with the Affiliate Transaction Rules. The Commission also does not find OPC's argument persuasive that Empire should be required to apply its cost of short-term debt to 100 percent of its CWIP balances to determine the AFUDC rate to calculate additions to the rate base.

In this Report and Order, the Commission followed OPC's recommendation to base Empire's capital structure on LUCo's capital structure, which the Commission finds is the appropriate way to address the impact of this affiliate transaction on the rate base. However, the Commission additionally finds that to the degree that any of the $450,000 origination fee from Empire's $90 million promissory note was included in the AFUDC calculation; it should be removed from rate base.

**10) Cash Working Capital**

**Findings of Fact**

243. Cash working capital (CWC) refers to the net funds required by Empire to finance goods and services used to provide service to customers.[336]

[336] Ex. 26, Lyons Direct, page 44.

244. Empire determined the CWC requirement using a lead-lag study, which compares the net difference between the revenue lag and expense lead.[337]

245. The revenue lag represents the number of days from the time customers receive their electric service to the time customers pay for electric service, while the expense lead represents the number of days from the time the Company receives goods and services used to provide electric service to the time payments are made for those goods and services. Together, the revenue lag and expense leads are used to measure the lead-lag days.[338]

246. If Empire has income tax expense, then its lead days for income tax expense would be applied to the approved level consistent with the IRS's payment schedule.[339] Empire has income tax expense included in its cost of service.[340] Empire calculated lead days for federal and state income taxes based on the number of days from the midpoint of the applicable tax period to the payment IRS dates.[341] Empire's tax paying affiliate does make quarterly payments to the IRS.[342] Empire determined that the appropriate number of expense lag days for its income tax lag was 39.38 days.[343]

247. OPC argued that an expense lag of 365 days should be used to measure income tax lag due to Empire's lack of income tax liability.[344]

248. The appropriate number of lag days is 39.38 because the Internal Revenue Code requires that corporate income taxes be paid on a quarterly basis.[345]

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[337] Ex. 26, Lyons Direct, page 44.
[338] Ex. 26, Lyons Direct, page 44.
[339] Ex. 27, Lyons Rebuttal, page 4.
[340] Ex. 124, Staff True-Up Accounting Schedule 9, page 5.
[341] Ex. 26, Lyons Direct, page 50.
[342] Ex.1018, Richard Responsive Supplemental Testimony, page 4.
[343] Ex. 26, Lyons Direct, Schedule TSL-SR1.
[344] Ex. 216, Riley Surrebuttal, pages 3-5.
[345] Section 6655 Internal Revenue Code.

249. Empire calculated lead days associated with cash vouchers based on a stratified sample of invoices paid with different weights for lead days in each stratum determined by a proportion of the total stratum transactions. Empire calculated 29.21 as the appropriate number of expense lag days for cash vouchers. [346]

250. Staff did not base its calculation on the number of transactions in each stratum, but instead accounted for the dollar amount of invoices in each class because lag is calculated based upon a dollar amount. Staff calculated 35.14 as the appropriate number of expense lag days for cash vouchers.[347]

251. Staff's cash voucher lag is consistent with previous Empire rate cases. The cash voucher lag from Empire's most recent rate case, File No. ER-2016-0023 was 35.28 days.[348]

252. Empire included bad debt expense in CWC, and calculated 42.13 as the appropriate number of lag days.[349] Empire's calculation reflects a collection lag from the time a customer bill is considered uncollectible and charged to bad debt expense to the time payment is received from customers.[350]

253. CWC measures the timing of a utility's cash flow that includes the revenues received from the customers and all of the payments made by the utility, because bad debt is a non-cash item Empire does not make payments to a supplier or other outside entity for bad debt, so the appropriate number of lag days is zero.[351]

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[346] Ex. 27, Lyons Rebuttal, page 5-6.
[347] Ex. 132, Giacone Surrebuttal, pages 5-6.
[348] Ex. 132, Giacone Surrebuttal, page 8.
[349] Ex. 26, Lyons Direct, Schedule TSL-SR1.
[350] Ex. 27, Lyons Rebuttal, page 7.
[351] Ex. 132, Giacone Surrebuttal, page 4.

254. Empire's vacation leave policy covers a calendar year and employees are granted their leave on January 1st of each year, which they can use throughout that calendar year. However, the policy allows for a deferral of up to five days of vacation to the following calendar year, to be used within the first quarter.[352]

255. Empire assumes the traditional approach, that most employees take their vacation uniformly throughout the year. Employees receive their vacation allotment on January 1st and take their vacation by December 31st. This approach assumes that vacation is taken at the midpoint of the year. Thus, the appropriate number of lead days to use for vacation pay is 182.50 days.[353]

256. Staff argued that an adjustment to the traditional approach for vacation day lag was needed to account for the five days of vacation Empire employees can carry over to the following year.[354] While Staff proposed a numerical adjustment in its stated position on this issue, it did not offer any supportive evidence into the record.

**<u>Conclusions of Law</u>**

No additional Conclusions of Law are required for this issue.

**<u>Decision</u>**

The Commission finds that the appropriate expense lag days for income tax is 39.38 days.

The Commission finds that the appropriate expense lag days for cash vouchers is 35.14 days.

[352] Ex. 132, Giacone Surrebuttal, page 2.
[353] Ex. 27, Lyons Rebuttal, page 7.
[354] Ex. 132, Giacone Surrebuttal, page 3.

The Commission finds that bad debt expense is a component of CWC, and the appropriate expense lag days for bad debt is zero days, because no cash is expended for bad debt.

The Commission finds that the appropriate number of expense lag days for employee vacation is 182.5 days.

**11) Accumulated Deferred Income Tax**

**Findings of Fact**

257. Empire's Accumulated Deferred income taxes (ADIT) represents, a net prepayment of income taxes by customers prior to tax payment by Empire.[355]

258. Empire may deduct depreciation expense on an accelerated basis for income tax purposes, the amount of depreciation expense used as a deduction for income tax purposes by Empire is considerably higher than the amount of depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income tax reserves to the future. The net credit balance in the ADIT accounts reserve represents a source of cost-free funds to Empire. Therefore, Empire's rate base is reduced by the ADIT balance to avoid having customers pay a return on funds that are provided cost-free.[356]

259. The net operating loss (NOL) is the result of Empire's use of the 50 percent first-year bonus depreciation that was available to utilities prior to the 2017 Tax Cuts and Jobs Act.[357]

[355] Ex. 101, Staff Direct Report, page 24.
[356] Ex. 101, Staff Direct Report, pages 24-25.
[357] Ex. 5, Richard Rebuttal, page 8.

260. If the use of accelerated tax depreciation reduces current income tax expense to a negative number, a NOL results. NOLs are carried forward to possibly offset future current income tax expense and cash outflows.[358]

261. The IRS has issued private letter rulings providing that an NOL deferred tax asset resulting from accelerated tax depreciation should be offset against a plant deferred tax liability also resulting from accelerated tax depreciation for ratemaking purposes.[359]

262. OPC's argument that Empire is not entitled to a reduction for a NOL because Empire is included in the consolidated income tax return filed by the Liberty Utilities, denies Empire a reduction it would otherwise be allowed as a stand-alone company.[360]

263. General ledger account 190.125 (Financial Accounting Standard (FAS) 123) is the deferred tax asset for stock-based compensation. Normalized payroll did not include any stock-based compensation, so any deferred tax impact of stock-based compensation expense should not be included in ADIT balances for rate base.[361]

264. Empire provided no persuasive evidence as to why FAS 123 should be included in ADIT.[362]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

Empire's use of accelerated tax depreciation reduced Empire's income tax expense to a negative number, which resulted in an NOL. The NOL offsets the ADIT

[358] Ex. 5, Richard Rebuttal, page 8.
[359] Ex. 5, Richard Rebuttal, page 9.
[360] Ex. 216, Riley Surrebuttal, page 3.
[361] Ex. 131, Foster Surrebuttal True-Up, page 2.
[362] Ex. 5, Richard Rebuttal, page 7.

liabilities. This is appropriate since the NOL did not reduce current income tax payments and did not provide the company with a no-cost source of capital. OPC's argument that Empire's NOL should be disregarded because Empire is included in Liberty Utilities' consolidated tax return fails to explain how the deferred NOL income tax benefit of accelerated depreciation should be accounted for and deprives Empire of what it would otherwise be allowed as a stand-alone company. The Commission finds that Empire's booked accumulated deferred federal income tax should include a reduction for the NOL.

Empire provides no persuasive evidence as to why FAS 123 should be included in ADIT, but merely argues that if the underlying stock-based compensation is included by the Commission in normalized payroll levels, the FAS 123 deferred tax asset should also be included in the ADIT balances. The Commission finds that the FAS 123 deferred tax asset for stock-based compensation should not be included in ADIT balances for rate base since it accepts Staff's normalized payroll levels that exclude stock-based compensation.

**12) Tax Cut and Jobs Act of 2017 federal income tax rate reduction from 35% to 21% impact for the period January 1 to August 30, 2018**

**<u>Findings of Fact</u>**

265. The Commission opened File Nos. ER-2018-0228 and ER-2018-0366 to consider the impact of the Tax Cuts and Jobs Act of 2017 (TCJA) and to appropriately adjust the Company's rates following the passage of Section 393.137 RSMo. The Commission directed Empire to establish a regulatory liability to address the impact of the TCJA on Empire's rates from the date of the tax rate reduction to the effective date of

lower base rates for Empire (January 1, 2018 - August 30, 2018), also known as the stub period.[363]

266. The Commission ordered Empire to defer approximately $11.7 million of stub period tax savings benefits (stub period revenue) on its balance sheet as a regulatory liability.[364]

267. The Commission did not address any ratemaking treatment regarding the stub period revenue in File No. ER-2018-0366, including whether the stub period revenue can or should be returned to the ratepayers, but postponed that decision to be addressed in this general rate case. [365]

268. Staff's proposal that the Commission amortize the regulatory liability over five years and not include the unamortized balance of the stub period revenue regulatory liability in rate base[366] is reasonable and aligns with the intent of the legislature in enacting Section 393.137 RSMo.

269. Empire's argument that it would be inequitable to return the stub period revenue to the ratepayers, and that it earned less than its allowed return during the stub period[367] is both irrelevant and is credibly contradicted by OPC's witness, whose analysis of the Empire's financial surveillance reports for the 12-month period ending September 30, 2018, indicate that Empire was substantially exceeding its authorized ROE.[368]

270. OPC states that the $11.7 million represents interest free money to Empire and that the Commission usually adjusts a company's rate base for its use of interest free

[363] Ex. 4, Richard Corrected Direct, page 13.
[364] Ex. 101, Staff Direct Report, page 55.
[365] Ex. 4, Richard Corrected Direct, page 13.
[366] Ex. 101, Staff Direct Report, page 56.
[367] Ex. Ex. 4, Richard Corrected Direct, page 13.
[368] Ex. 214, Riley Direct, page 5.

money from its retail customers. OPC suggests that any unamortized balance should be an offset from rate base.[369]

271. The stub period revenue represents a tax benefit received by Empire over a relatively short period of time; recognizing that benefit over a finite five-year period is more appropriate than including this amount in rates as a long-term reduction to rate base.[370]

272. Amortizing the stub period revenue over five years with no rate base offset for the unamortized amount is consistent with prior rate treatment of many extraordinary deferrals granted by the Commission in that it effectively "shares" the financial impact of the extraordinary event in question between the utility and its customers. Passing on to customers the dollar value of the TCJA tax benefits in rates over time through an amortization, but excluding the unamortized amount from rate base, appropriately shares the benefit of unanticipated windfalls such as the stub period revenue between a utility and its customers.[371]

273. The amortization of the TCJA stub period revenue over five years reduces Empire's total amortization expense by $2,345,691.[372]

274. Staff's position to amortize over five years with no rate base offset for the unamortized amount is the most fair and equitable treatment of the impact of the TCJA for ratemaking purposes.[373]

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[369] Ex. 215, Riley Rebuttal, page 2.
[370] Ex. 154, Oligschlaeger Surrebuttal, page 6.
[371] Ex. 154, Oligschlaeger Surrebuttal, page 6.
[372] Ex. 102, Staff Direct Accounting Schedules.
[373] Ex. 154, Oligschlaeger Surrebuttal, page 6.

## **Conclusions of Law**

CC. Section 393.137.3, RSMo, states in part:

> If the rates of any electrical corporation to which this section applies have not already been adjusted to reflect the effects of the federal 2017 Tax Cut and Jobs Act, … the commission shall have one time authority … to adjust such electrical corporation's rates prospectively so that the income tax component of the revenue requirement used to set such an electrical corporation's rates is based upon the provisions of such federal act without considering any other factor as otherwise required by section 393.270. The commission shall also require electrical corporations … to defer to a regulatory asset the financial impact of such federal act on the electrical corporation for the period of January 1, 2018, through the date the electrical corporation's rates are adjusted on a one-time basis as provided for in the immediately preceding sentence. The amounts deferred under this subsection shall be included in the revenue requirement used to set the electrical corporation's rates in its subsequent general rate proceeding through an amortization over a period determined by the commission.

DD. The Commission ordered Empire in File No. ER-2018-0366, to record a $11.7 million regulatory liability, representing the financial impact of the Tax Cut and Jobs Act of 2017 on Empire for the stub period, January 1, 2018 through August 30, 2018.

## **Decision**

Section 393.137.3, RSMo required Empire to defer the stub period revenue amount of $11.7 million. The statute also requires the Commission to include the deferred stub period revenue in its revenue requirement in Empire's subsequent rate case and amortize those amounts over a period determined by the Commission.

Empire's assertions that being ordered to return the stub period revenue would constitute retroactive ratemaking or that the amounts should not be returned because they were lawfully collected under Empire's approved tariff are overcome by the clear language of the statute; which specifically references the stub period: "the period of January 1, 2018, through the date the electrical corporation's rates are adjusted on a one-time basis." The stub period revenue is to be included in the revenue requirement and amortized over a period of time.

Likewise, OPC's argument that the stub period revenue should be immediately returned to the customers through a rate base adjustment is not contemplated by the statute. The Commission finds that the stub period revenue, the TCJA $11.7 million regulatory liability established in File No. ER-2018-0366, shall be amortized as a reduction to Empire's total amortization expense over five years with no rate base offset for the unamortized amount.

**13) Asbury and AAO**

**Findings of Fact**

172. For ratemaking purposes, a "Test Year" uses the test year income statement as a starting point for determining a utility's existing annual revenues, operating costs, and net operating income. An "Update" is a period used to consider factors that occur subsequent to the test year through a specific date. Updating a case does not change the test year, but rather, adjusts the test year to reflect audited results associated with factors considered through the update period. It represents the last date through which historical data is available to be audited.[374]

173. In a rate case, a "True-Up" can be used when significant changes in a utility's cost of service occur after the end of the update period for the test year but prior to the operation-of-law date.[375]

174. In this case, the Commission issued an order that established the test year as the 12 months ending March 31, 2019, with an update period through September 30,

[374] Ex. 101, Staff's Direct Report, pages 1-3.
[375] Ex. 101, Staff's Direct Report, page 2.

2019. The order also allowed for items to be trued-up through January 31, 2020, based off of known and measurable information.[376]

175. The Commission denied a motion by OPC to modify the test year to include isolated adjustments for the retirement of the Asbury coal-fired power plant.[377]

176. Asbury was an approximately 200 MW cyclone steam generator commissioned in 1970, which burned a blend of low-sulfur Wyoming coal and local bituminous coal. In 2014, Empire retrofitted Asbury with an air quality control system, which was intended to extend the expected retirement date of the plant from 2030 to June 2035.[378]

177. In June 2019, Empire addressed the Asbury plant in its Triennial Integrated Resource Plan (IRP). Empire's IRP modeling showed that in 2018, Asbury had a 48 percent average capacity factor and because of the additional capital investment necessary to meet environmental regulations relating to Asbury's coal ash handling system and the energy market created by the SPP[379] integrated marketplace, the Asbury plant was not a cost-effective resource.[380]

178. Empire planned to close the Asbury plant no later than June 2020 in order to avoid the additional investment that would be required to comply with environmental regulations governing coal ash. Asbury would not have been allowed to operate beyond

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[376] *See* Commission's October 17, 2019 Order Setting Procedural Schedule and Other Procedural Requirements.
[377] Order Denying Public Counsel's Motion to Modify the Test Year, and Order to File Suggestions for Inclusion in an Accounting Authority Order. January 28, 2020.
[378] Ex. 203, Mantle Direct, pages 21-22.
[379] SPP is a regional transmission organization that provides electric transmission services on behalf of its transmission-owner members pursuant to its regional tariff. *E. Texas Elec. Coop., v. F.E.R.C.,* 331 F.3d 131, 133 (D.C. Cir. 2003).
[380] Ex. 41, Wilson Direct, page 6; *See also,* Empire's 2019 IRP filed June 28, 2019, in File No. EO-2019-0049.

that time without making considerable investments or incurring significant costs to dispose of the coal ash.[381]

179. Empire identified certain Asbury assets to be reused and/or repurposed for the operations and maintenance (O&M) of other generation units, including basing the O&M of its future wind farms at the Asbury facility.[382] Empire also continued to evaluate the ultimate plan for the remaining Asbury assets.[383]

180. In January 2020, Empire indicated it was exploring options for the continued use of buildings and equipment at the Asbury location but had insufficient data.[384]

181. Black and Veatch was engaged to perform a multi-part study for Empire with regard to the closure of Asbury. The goal of Phase 1 of the study was to develop an initial Plant Retirement Plan that would be used to support the preferred plan for the plant's final disposition by analyzing multiple options. As of May 6, 2020, Empire was still in the process of working through the final stages of Phase 1. Phase 2 will be the creation of the final plan based on Empire's decision on the ultimate disposition of the facility.[385]

182. Asbury last generated power in December 2019.[386] However, Asbury's assets (excluding those used elsewhere) were removed from service for accounting purposes as of March 1, 2020; the same day Asbury was de-designated from the SPP Market.[387]

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[381] Ex. 4, Richard Corrected Direct, page 25.
[382] Ex. 217, Robinett Direct, page 6.
[383] Ex. 1012, Wilson Supplemental, page 1.
[384] Ex. 217, Robinett Direct, Schedule JAR-D-2, page 5.
[385] Ex. 1012, Wilson Supplemental, page 2.
[386] Ex. 219, Robinett Surrebuttal/True-Up, page 1.
[387] Ex. 1012, Wilson Supplemental, pages 1-2.

183. The closure of Asbury was expected to impact Empire's O&M expense, including reducing costs to maintain the plant, such as materials expense as well as labor costs associated with the plant.[388]

184. However, since Asbury's planned retirement was after January 31, 2020, all of the impacts of the retirement could not be known or measurable before the end of the true-up period, including the changes in O&M charges.[389]

185. After the retirement, Asbury would still require O&M related to continued retirement activities. The appropriate level of O&M for Asbury is further complicated by Empire's potential use of the facilities for other future generation facilities.[390]

186. Empire proposed the Commission approve an AAO for items related to the Asbury closure.[391]

187. An AAO occurs when the Commission authorizes a utility to account for particular financial items in a different manner than what is normally required under the FERC USOA.[392] Although the USOA's general guidance is that net income should reflect all items of profit and loss during a period,[393] instruction number seven of the USOA allows for special treatment of certain items related to an extraordinary event that is significant and different from the ordinary and typical activities of a company.[394]

188. An AAO permits deferral from one period to another. The items deferred are booked as a regulatory asset or liability in the appropriate USOA accounts. During a

[388] Ex. 1012, Wilson Supplemental, pages 1-2 26.
[389] Ex. 4, Richard Corrected Direct, page. 2; and Ex. 1017, Richard Supplemental Testimony, page 20.
[390] Ex. 217, Robinett Direct, page 7.
[391] Ex. 1017, Richard Supplemental Testimony, page 20.
[392] Ex. 162, Oligschlaeger, Supplemental, page 6.
[393] 18 C.F.R. Part 101, General Instruction 7.
[394] Ex. 1017, Richard Supplemental Testimony, page 20-21.

subsequent rate case, the Commission determines what portion, if any, of the deferred amounts will be addressed in rates.[395]

189. Although the retirement of plant assets in general may be common, the retirement of a generating station can in some limited circumstances be considered extraordinary. This is due to the high dollar value of the generating units and the rarity of the retirement of units of this nature.[396]

190. For many years, Asbury was the primary baseload generating unit owned by Empire. The retirement of a unit of this size was unprecedented for Empire, especially since the retirement occurred well before the end of Asbury's estimated depreciable life.[397] The unrecovered original book cost for Asbury is estimated to be around $200 million.[398]

191. Empire acknowledged its decision to retire Asbury was not usual in nature or a frequent occurrence.[399]

192. The Asbury retirement is expected to have a financial impact of at least five percent of the Empire's annual net income.[400]

193. An AAO could be issued directing Empire to record for consideration in its next rate case all impacts of the retirement of Asbury, including the return on and of the rate base associated with Asbury, depreciation, and any reduction in O&M expense.[401]

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[395] Ex. 129, Bolin Surrebuttal True-Up, page 2; and Ex. 1017. Richard Supplemental Testimony, page 20.
[396] Ex. 162, Oligschlaeger, Supplemental, page 7.
[397] Ex. 162, Oligschlaeger, Supplemental, page 7-8.
[398] Ex. 217, Robinett Direct, page 2.
[399] Ex. 1017, Richard Supplemental Testimony, page. 21.
[400] Ex. 162, Oligschlaeger, Supplemental, pages 6-7.
[401] Ex. 1017, Richard Supplemental Testimony, page 20; and Ex. 162, Oligschlaeger, Supplemental Testimony, pages 8-9.

194. Although deferral through an AAO may require customers to wait to receive the benefits of the Asbury retirement in rates, the deferral approach can capture all the savings, including savings that occur prior to when rates will go into effect in this case.[402]

195. Empire anticipates filing its next rate case in the third quarter of 2020 to request recovery for wind generation acquisitions.[403]

## **Conclusions of Law**

EE. A regulated utility's rates are established prospectively in periodic ratemaking proceedings, based on the utility's revenues and expenses during an earlier test year.[404] The use of a test year is the accepted way to establish future rates. The test year is a tool to find the relationship between investment, revenues, and expenses with certain adjustments made to the test year figures.[405]

FF. The criteria for determining whether an event outside the test year should be included is whether the proposed adjustment: 1) is known and measurable; 2) promotes the proper relationship of investment, revenues and expenses; and, 3) is representative of the conditions anticipated during the time the rates will be in effect.[406]

GG. When setting rates, the choice of method to adjust the test year for known and measurable changes is a factual determination within the Commission's expert discretion. The Commission is not required to recognize and incorporate all known and measurable events outside the test year so long as the results are rates that are just and reasonable.[407]

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402 Ex. 162, Oligschlaeger, Supplemental Testimony, pages 9-10.
403 Ex. 1017, Richard Supplemental, page 12. Maini Direct, page 35.
404 *State ex rel Aquila Inc. v Public Service Com'n of State*, 326 S.W.3d 20 at 28 (Mo. App. W.D. 2010).
405 *State ex rel GTE North Inc. v Missouri Public Service Com'n* 835 S.W.2d 356, 368 (Mo. App. W.D. 1992).
406 *State ex rel GTE North Inc. v Missouri Public Service Com'n* 835 S.W.2d 356, 368 (Mo. App. W.D. 1992).
407 *State ex rel GTE North Inc. v Missouri Public Service Com'n* 835 S.W.2d 356, 370 (Mo. App. W.D. 1992).

HH. SPP identifies generation owned, purchased or leased as a Network Resource if it is designated to serve load under SPP's Open Access Transmission Tariff.[408]

II. Before a generating resource can terminate its designation as a Network Resource, SPP's Regional Tariff requires a request be submitted to terminate the designation status. The request must indicate the date and time that the termination is to be effective.[409]

JJ. The Commission has the discretion to prescribe uniform methods of keeping accounts, records and books to be observed by electrical corporations and may prescribe, by order, forms of accounts and records to be kept.[410]

KK. Except as otherwise provided, electric utilities shall keep accounts in conformity with the USOA.[411]

LL. The USOA, Instruction No. 7 states that although net income should reflect all items of profit and loss during the period, an exception is made for extraordinary items, which are those items related to the effects of events and transactions which have occurred during the current period and which are of unusual nature and infrequent occurrence. They will be events and transactions of significant effect which are abnormal and significantly different from the ordinary and typical activities of the company, and which would not be reasonably expected to recur in the foreseeable future[412].

[408] *See* Southwest Power Pool, Inc., Open Access Transmission Tariff, Sixth Revised Volume No. 1, Part III, Section 30.1. https://spp.etariff.biz:8443/viewer/viewer.aspx
[409] *See* Southwest Power Pool, Inc., Open Access Transmission Tariff, Sixth Revised Volume No. 1, Part III, Section 30.3. https://spp.etariff.biz:8443/viewer/viewer.aspx
[410] Section 393.140.4, RSMo.
[411] 20 CSR 4240-20.030.
[412] 18 C.F.R. Part 101, General Instruction No. 7.

MM. Although the ability to use a deferral mechanism is a policy decision within the Commission's discretion, the Commission has generally followed the guidance in the USOA that costs should not be deferred to another accounting period except for "extraordinary items."[413]

NN. The purpose of an AAO is to defer and track certain extraordinary revenues or costs for consideration in a future rate case. The existence of an AAO does not guarantee any particular treatment of the deferred items in ratemaking.[414]

OO. The Commission has authority to defer extraordinary costs of a utility for consideration in a later period. In doing so, it is not engaging in single-issue rate making.[415]

**Decision**

When the Commission established the test year for this case, it evaluated the treatment options for Asbury, which no party disputed would be retired before the rates for this case went into effect. The Commission specifically rejected OPC's request to include isolated adjustments for the Asbury retirement in the true-up period. The Commission limited the scope of the true-up due to concerns that all the impacts of the Asbury retirement would not be known and measurable within the time available. In addition, the planned reuse of portions of the Asbury facilities made the isolated adjustments OPC requested unfeasible.

OPC contends that it is unlawful and unreasonable to include in rates the costs associated with the Asbury plant. Instead, OPC proposes that going forward, the Commission remove the costs associated with operating Asbury, including depreciation

[413] *Kan. City Power v. Public Serv. Comm*, 509 S.W.3d 757 at 770.(Mo.App. W.D. 2016).
[414] *Missouri Gas Energy v. Pub. Serv. Com'n of Mo.*, 978 S.W. 2d 434 (Mo. App. W.D. 1998).
[415] *State ex rel. Office of Pub. Counsel v. Pub. Serv. Com'n of Mo.* 858 S.W. 2d 806 (Mo. App. W.D. 1993).

expense and O&M cost. For various reasons, the Commission disagrees with OPC's position.

When OPC filed its direct testimony on January 15, 2020, OPC initially argued that with a March 1, 2020 retirement date, Asbury's depreciation expense and O&M cost should be removed from Empire's cost of service since the new rates are expected to go into effect in July 2020, months after Asbury's retirement. OPC was concerned that ratepayers would be paying for plant that was no longer providing them benefits.

After discovering Asbury last generated power in December 2019 (prior to the January 31, 2020 true-up cutoff date), OPC again requested the Commission treat Asbury's retirement in this case and include it in the true-up. While OPC may be correct that Asbury last generated power in December 2019, OPC incorrectly assumes that this is when Asbury must cease being an asset. Asbury was still designated a generating Network Resource by SPP - meaning the RTO recognized Asbury as a unit capable of meeting load requirement - until it was "de-designated" after March 1, 2020. Under the RTO's tariffs, SPP's acceptance was required before Asbury's designation could be terminated.[416] It would be reasonable to find that the retirement of Asbury could not occur before its status as a generator designated to serve load changed within SPP.

However, even if OPC is correct and the retirement of Asbury should be set as the day it last generated power in December 2019, the retirement still occurred after March 31, 2019, the end of the test year. OPC ignores the essential reason the Commission initially rejected its request to true-up isolated adjustments for Asbury. When determining if events outside the test year should be included, the Commission considers whether the

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[416] *See* Southwest Power Pool, Inc., Open Access Transmission Tariff, Sixth Revised Volume No. 1, Part III, Section 30.3. https://spp.etariff.biz:8443/viewer/viewer.aspx

proposed adjustments are known and measurable and are representative of the conditions anticipated during the time rates will be in effect.[417]

Regardless of whether Asbury retired on December 12, 2019, or after March 1, 2020, the impacts of the Asbury retirement are not known or measurable. OPC's witness was only able to provide an estimated range for O&M expenses to be removed from rates, since, as he acknowledged, savings would be decreased by the O&M costs for the retirement process.[418] While OPC acknowledges Empire will incur O&M costs for the retirement they also recommend Empire recover no O&M costs for Asbury.[419] OPC's proposal to remove all O&M costs for Asbury does not represent the anticipated conditions when the new rates are in effect since Empire will be incurring costs while it repurposes some of Asbury's facilities and also performing retirement activities.

Some of Asbury's facilities will be used as the base for O&M operations for Empire's planned wind farms and Empire is still evaluating if it will reuse other existing facilities. Although Asbury may not be generating electricity, some of its facilities may still be used and useful. However, since Phase 1 of the Plant Retirement Plan was still ongoing as of May 6, 2020, it is impossible to accurately determine in this case the proper level of ongoing expense, including which Asbury plants will continue to have depreciation expense and which will not.OPC recommends the Commission remove all Asbury-related expenses and revenues from rates in this case and then set up a deferral account to track retirement and possible dismantlement costs for future consideration.[420] OPC's proposal will require Empire to wait until rates are set in the next rate case before the Company

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[417] *State ex rel GTE North Inc. v Missouri Public Service Com'n* 835 S.W.2d 356, 368 (Mo. App. W.D. 1992).
[418] Ex. 217, Robinett Direct, page 7.
[419] Ex. 217, Robinett Direct, page 7.
[420] Ex. 219 Robinett Surrebuttal/True-Up, page 2.

can possibly recover its ongoing retirement costs. It will also involve a limited deferral. Since OPC would only exclude costs beginning with new rates in July, it removes the possibility customers could recoup costs from the time of retirement until July.

The courts have found that, “[w]hether a cost should be afforded different treatment and merits a deferral directly impacts the PSC’s chosen methodology for setting rates and is necessarily a discretionary judgment that is within the expertise of the PSC….”[421]It is both lawful and reasonable for costs related to Asbury to be included in rates. While Empire should not be allowed to have a generating plant sit idle indefinitely while recovering costs in rates, that is not the current situation. The transitional period in which some Asbury facilities are being retired and other assets may be repurposed occurred after the January 31, 2020 true-up cutoff and will continue after this report and order is issued. For this reason, the impacts of Asbury’s retirements should be considered in their entirety in the next rate case and not as isolated adjustments in this case.

Excluding the Asbury retirement from the true-up adjustments does not mean the Commission intends to grant Empire a windfall. Although the inclusion in rates of all costs related to a fully operational Asbury plant may not be an accurate representation of Empire’s operating expense, an AAO could be issued directing Empire to record for consideration in its next rate case all impacts of the retirement of Asbury, including the return on and of the rate base associated with Asbury, depreciation, and any reduction in O&M expense. The Commission could then make a determination on the treatment for Asbury’s retirement in the next rate case.

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[421] *Kan. City Power & Light Co.’s Request for Auth. To Implement a General Rate Increase for Elc. Serv. V. MO. Pub. Serv. Comm’n*, 509 S.W.3d 757, 770 (Mo.App. 2016).

Empire's customers will not be disadvantaged by the deferral of the impacts of the Asbury retirement, compared to the option of reflecting the net savings from the retirement in rates set in this case. The difference between the deferral and immediate rate recognition scenarios is primarily one of timing. While customers will have to wait until rates for Empire's next rate case are set to receive the direct benefits of the Asbury retirement in rates if the impacts are deferred, the full amount of those net savings will still be captured and available to flow to customers in the next rate case, which Empire plans to file soon. The evidence shows that the retirement of the Asbury power plant is extraordinary, unusual, unique, and not recurring. The Commission finds that it is appropriate to issue an AAO to allow the Commission to defer a final decision until more is known about the financial impact of the retirement.

The signatories to the Agreement agreed that any order establishing an AAO for Asbury should direct Empire to establish a regulatory asset/liability, beginning January 1, 2020, to reflect the impact of the closure of Asbury and require Empire to separately track and quantify the changes from the base amounts, as reflected in Appendix D to the Agreement, of the following categories of rate base and expense[422]:

a. Rate of return on Asbury Plant,
b. Accumulated Depreciation,
c. Accumulated and Excess Deferred Income Tax,
d. Fuel inventories assigned to the Asbury Plant,
e. Depreciation expense,
f. All Non-fuel/ non-labor operating and maintenance expenses,
g. All labor charges for maintaining and operating the Asbury Plant,

[422] Ex 750, Global Stipulation and Agreement.

h. Property taxes assigned to the Asbury Plant,

i. Any costs associated with the retirement of the Asbury Plant, including dismantlement and decommissioning - Non-Empire labor excluded.

OPC's witness also proposed the following items be included in an AAO:[423]

a. Cash working capital and income tax gross up associated with Asbury.

b. Any fuel or SPP revenues or expenses associated with Asbury that do not flow through the FAC.

c. Revenue from scrap value or value of items sold.

Having found that the retirement of the Asbury power plant is extraordinary, the Commission will direct Empire to establish an AAO to defer costs and revenues associated with its retirement. OPC argues that the appropriate time to start the deferral is, "sometime before the earliest proposed retirement date of December 12, 2019."[424]

Beginning the deferral on January 1, 2020, should provide parties the opportunity to argue various positions in the next rate case as to retirement events while preserving accounting of the amounts for consideration regardless of the Commission's determination as to the retirement.

In comparison, starting the deferral on an earlier date, such as the middle of a month, may cause difficulties distinguishing costs for auditing purposes. This may outweigh any benefits in quantifying those costs or revenues. Therefore, the deferral will begin January 1, 2020, until the Commission makes a decision regarding the AAO deferrals in Empire's next rate case. The Commission orders Empire to record as

[423] Ex. 299-11, Robinett Testimony In Response To Commission Questions, page 1; and Office of Public Council's Response to Commission's Order Denying Public Counsel's Motion to Modify the Test Year, and Order to File Suggestions for Inclusion in an Accounting Authority (April 3, 2020).

[424] Ex. 299, Robinett Reply to Testimony Responding to Commission Questions, pages 9-10.

regulatory assets and regulatory liabilities the revenues and expenses in the categories identified by the signatories to the Agreement and proposed by OPC.

**<u>Empire's Objection to Offers of Evidence</u>**

On May 6, 2020, Empire filed its *Objections to Offers of Evidence*, objecting to specific testimony offered by OPC witnesses relating to the retirement of Asbury. Empire requested the Commission exclude certain portions of OPC's surrebuttal testimony or provide the Company and other parties the opportunity to submit additional testimony should the Commission overrule its objection and admit OPC's surrebuttal testimony. The Commission did not rule on Empire's motion until this Report and Order wherein the motion is overruled. OPC's surrebuttal testimony pertaining to Asbury was admitted into the record. The Commission has addressed the Asbury issue identified in this case concerning whether it is lawful and reasonable to include costs for Asbury in rates. While the analysis on that issue addresses OPC's position, the testimony presented by OPC was not sufficient to persuade the Commission that adjustments for Asbury's retirement are appropriate in this case. Even though Empire was not given an opportunity to present additional testimony, it is unlikely that any further testimony from Empire or any other party would impact the Commission's decision, which is consistent with Empire's position. To the extent that Empire or other parties seek to admit testimony responsive to OPC's statements about events surrounding the retirement of Asbury or how costs and revenues for the Asbury assets should ultimately be treated, this case is not the proper place for those filings. Those issues can be addressed by the parties in Empire's next rate case.

## 14) Fuel Inventories

**Findings of Fact**

275. To determine the amount of coal inventory, the average daily burn by unit must be calculated. The average daily burn by unit is derived by dividing the annualized tons burned by the difference between 365 days and the number of annual planned outage days. Then, the average daily burn is multiplied by an appropriate number of days of inventory for each plant resulting in a burn inventory.[425]

276. Staff used a 60-day calculation to establish Empire's rate base investment in the coal inventory maintained both at KCPL's Iatan Generating Stations (Empire owns 12 percent of Iatan 1 and 2) and Plum Point Energy Station (Empire owns 7.52 percent of Plum Point).[426]

277. Empire acknowledged that Asbury has not operated as much as it did in the past, but this lower level of operation is already reflected in the average daily burn that Staff used in its calculation.[427]

278. Based upon information as of the end of the true-up period of January 31, 2020, and a retirement date of March 1, 2020, Staff determined that appropriate level of coal inventory was 18 days for Asbury.[428]

279. Empire set the number of burn days inventory for the Asbury 1 unit at 60 days consistent with past rate cases and inventory levels of other Empire coal units.[429]

280. OPC argues that the appropriate number of burn days for Asbury is zero.

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[425] Ex. 101, Staff Direct Report, pages 23-24.
[426] Ex. 101, Staff Direct Report, page 24.
[427] Ex. 15, Tarter Rebuttal, 15-16.
[428] Ex. 138, McMellen Surrebuttal True-Up, pages 2-3.
[429] Ex. 101, Staff Direct Report, page 24.

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission finds that the appropriate number of burn days to use for Asbury coal inventory is 60 days. The Commission is not persuaded that any consideration of the impact of Asbury's anticipated retirement date of March 1, 2020 should be included in the calculation of Asbury fuel inventory since it is beyond the end of the true-up period in this rate case. Fuel inventories will be further addressed in Empire's next rate case to be filed in the third quarter of 2020. The financial impact of Asbury's retirement, including fuel inventories, will be addressed in that case through an AAO ordered by the Commission in this Report and Order. The treatment of Asbury's retirement through an AAO will allow fuel inventory changes to be captured and treated with other Asbury retirement related issues that impact Empire's rates.

### 15) Operation and Maintenance Normalization

## Findings of Fact

281. A utility's O&M expenses are a major component of the revenue requirement.[430]

282. The O&M expense in this issue refers to non-labor O&M costs for each of Empire's generating units.[431]

283. Empire calculated O&M costs in the amount of $32,731,672 using actual test year amounts normalized for boiler plant maintenance.[432]

[430] Ex. 4, Richard Corrected Direct, page 8.
[431] Ex. 5, Richard Rebuttal, page 18.
[432] Ex. 62, Operation and Expense Workpapers, and Ex. 7 Richard True-up Direct, page 15.

284. Staff calculated O&M costs in the amount of $28,877,386 prior to the application of jurisdictional allocation factors.[433]

285. While Staff recorded Empire's plant major overhaul schedule incorrectly, Staff reviewed the maintenance accounts and analyzed each plant separately to determine the trend, so mistakenly recording the major overhaul schedule did not affect Staff's final analysis or O&M expense recommendation.[434]

286. Staff used a five-year average to normalize O&M expenses for Asbury, State Line Combined Cycle, State Line Common, State Line 1, and Energy Center and Ozark Beach. Staff used a six-year average to normalize O&M expenses for Iatan 1 and a three-year average to normalize O&M expenses for Riverton.[435]

287. O&M expenses tend to fluctuate from year to year, because unscheduled outages occur at irregular and unpredictable times, and major planned outages do not occur annually.[436]

288. It is not appropriate to adjust actual utility expenses for ratemaking purposes based on overall economic indexes (inflation) that are not company or utility-specific. Those indicators are more reflective of the economic conditions in the United States.[437]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission determines that the use of an average of historical O&M expenses to normalize O&M expenses provides the most reliable result because of the

[433] Ex. 124, Staff True-up Accounting Schedules
[434] Ex. 143, Sarver Surrebuttal True-Up, page 6.
[435] Ex. 143, Sarver Surrebuttal True-Up, page 6-7
[436] Ex. 101, Staff Direct Report, page 70.
[437] Ex. 143, Sarver Surrebuttal True-Up, page 7.

yearly fluctuation of O&M costs. These fluctuations in costs are related to both unscheduled outages that are irregular and unpredictable and major planned outages that do not occur annually. The Commission therefore finds that $28,877,386 is the appropriate amount of O&M expense to include in Empire's revenue requirement before jurisdictional allocation factors are applied. The Commission does not find that it is appropriate to adjust the O&M expense amount for inflation. The Commission finds that the appropriate normalized average of years for Riverton is three years, for State Line Combined Cycle Unit and for the Common Unit and State Line Unit 1 unit the appropriate normalized average of years is five years.

**16) Pension and post-employment benefits (OPEB) (FAS 87 and FAS 106)**

**<u>Findings of Fact</u>**

289. Empire provided two actuarial valuations to Staff, one based on acquisition accounting and one, for regulatory purposes, calculated as if the acquisition did not occur.[438]

290. The Merger Stipulation in File No. EM-2016-0213, states in paragraph three that "The Joint Applicants will ensure that the merger will be rate-neutral for Empire's customers." The use of regulatory accounting for ongoing Pension and OPEB balances is necessary to comply with the Commission's order in that case.[439]

291. Acquisition accounting requires that some unamortized balances in the plans be immediately recognized as part of the business combination. Since amortization of these balances is a component of pension and OPEB expense, eliminating them from

[438] Ex. 12, Fallert Rebuttal, page 2.
[439] Ex. 13, Fallert True-Up Direct, pages 2-3.

the rate calculation would have an impact on customer rates, which would not comply with the Commission's order in File No. EM-2016-0213.[440]

292. Staff used acquisition accounting amounts for the year 2018 in its direct filing.[441]

293. Staff's pension expense adjustment incorporates all of the components of financial and regulatory pension expense including those components recorded by Empire in account 426, allowing Empire full recovery of its pension costs.[442]

294. The Financial Accounting Standards Board (FASB) Accounting Standards Update No. 2017-07, 14 Compensation-Retirement Benefits, is the rule Empire relies on. It requires that the non-service cost components of pension and OPEB expense be reported outside of the subtotal of income from operations. Empire determined that account 426500, Other Income Deductions, would be the correct place to record these expenses in compliance with this rule.[443]

295. Paragraph 10 of the stipulation and agreement approved in Empire's last general rate case, File No. ER-2016-0023 states: "The prepaid pension asset balance as of March 31, 2016 is $23,314,960, Missouri jurisdictional." [444] Empire's calculation of prepaid pension starts with that balance and adds activity to arrive at a prepaid pension balance of $26,269,345.

296. Some management employees receive benefits under Empire's Supplemental Employee Retirement Program (SERP). The IRS designated this program

[440] Ex. 13, Fallert True-Up Direct, page 3.
[441] Ex. 12, Fallert Rebuttal, page 2.
[442] Ex. 143, Sarver Surrebuttal True-Up, page 2.
[443] Ex. 1013, Fallert Supplemental, page 3.
[444] Order Approving Stipulation and Agreement, Attachment A, File No. ER-2016-0023, issued August 10, 2016.

as a non-qualified plan. In a non-qualified plan, the expense is not pre-funded, so the payment basis is appropriate.[445]

297. Empire recommends expense basis as a preferable approach to calculate SERP because: (1) the expense amount is independently determined by the company's actuary; (2) it is consistent with the calculation of similar items (qualified pensions and OPEBs); and, (3) the recognition of SERP on an expense basis, rather than a payment basis, more closely matches the benefits provided to customers.[446]

298. Empire's Rabbi Trust analysis for the cases modeled, indicates that the cost to ratepayers of reimbursing benefits as they are paid (payment basis) was lower than the cost of prefunding (expense basis).[447]

299. Staff's allocation of total SERP cost to Missouri expense is based on the percentage of total ongoing FAS 87 pension cost to the portion of this cost allocated to Missouri expense. This applies an allocation percentage developed for a qualified pension expense and not a non-qualified SERP expense. The appropriate SERP allocation percentage is 82.15 percent.[448]

300. In December 2018, $639,992 was reclassified from account 182353 to account 254101. Staff's true up calculation included the impact of this entry on account 254101 but did not include the impact on account 182353.[449]

301. Empire's true-up filing includes a total tracker balance of $12,260,836, which is $226,954 more than Staff's direct filing balance of $12,033,882. Empire's witness

[445] Ex. 101, Staff Direct Report, page 69.
[446] Ex. 12, Fallert Rebuttal, page 5.
[447] Ex. 94, Rabbi Trust Analysis.
[448] Ex. 12, Fallert Rebuttal, pages 5-6.
[449] Ex. 11, Fallert Direct, Schedule JAF-2.

attributes the increase to activity between September 30, 2019, and January 31, 2020, errors in Staff's balance for account 182359, and a double-count of adjustments to remove FAS 88 settlements (acquisition accounting basis) in Staff's direct filing.[450]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission finds most persuasive Empire's position that the regulatory accounting actuary report contains the appropriate data for determining Empire's pension and OPEB costs. However, Staff's jurisdictional allocation factors should be applied to pension and OPEB costs where applicable.

Accordingly, as pension and OPEB amounts that were previously charged to account 926 are now being charged by Empire to account 426, the Commission finds that these amounts charged to FERC account 426 should be included in pension and OPEB expenses.

The Commission finds that the payment basis is appropriate to calculate SERP costs because SERP costs are not pre-funded and Empire's own analysis indicates that costs to ratepayers to reimburse the SERP benefits are lower under the payment basis. The appropriate allocation percentage is 82.15 percent.

The Commission finds that the appropriate rate base and tracker amortization balances for accounts 182353 and 254101 are $12,260,836.

Based upon Empire's calculation of activity occurring since the Commission approved a stipulation and agreement in Empire's last rate case, File No. ER-2016-0023, setting the prepaid pension asset balance as of March 31, 2016, the Commission finds

[450] Ex. 13, Fallert True-Up Direct, page 5.

that the balance of the prepaid pension is $26,269,345 as of the end of the true-up period ending January 31, 2020.

**17) Affiliate Transactions**

**Findings of Fact**

302. Affiliated transactions are exchanges of good and services between a regulated utility and another entity sharing common ownership with the utility. Affiliated transactions are of concern to the Commission because of the prospect of a regulated entity's customers providing a "cross-subsidy" to the non-regulated operations of the firm owning both entities, by either paying excessive prices or receiving insufficient revenues for affiliated goods and services. The danger of cross-subsidy arises in affiliated transactions because such exchanges of goods and services are by definition not "arms-length" in nature; hence they are not conducted by two independent third parties each looking out for its own best interest.[451]

303. Empire is part of a multi-layered corporate structure. It is directly owned byLUCo, which in turn is owned by a string of affiliated companies, and ultimately by APUC. Empire receives a variety of corporate, administrative and support services from a number of upstream affiliated entities, as well as support services from Liberty Utilities Service Corp (LUSC).[452]

304. Liberty Utilities, through LUSC and Liberty Utilities (Canada) Corp., provides some services on a shared basis to Empire where there is an opportunity to realize economies of scale or other efficiencies. These services are provided and charged

[451] Ex. 114, Oligschlaeger Rebuttal, pages 1-2.
[452] Ex. 114, Oligschlaeger Rebuttal, page 3.

based on a direct charge or a defined cost allocation methodology as set forth in APUC's Cost Allocation Manual (CAM). [453]

305. APUC's CAM is based on the National Association of Regulatory Utility Commissions (NARUC) Guidelines for Cost Allocations and Affiliate Transactions. The fundamental premise of those guidelines and the CAM is to directly charge costs as much as possible and to use reasonable allocation factors where allocation of indirect costs is necessary and direct charging is not possible.[454]

306. All costs incurred that are directly related to a specific affiliate company or business unit are directly charged to that company or business unit. Costs that are not directly related to a specific utility are indirectly allocated between the regulated and unregulated business units using two Corporate Allocation Methods for business services and corporate services as described in the CAM.[455]

307. Empire states that APUC's CAM satisfies the Commission's affiliate transaction rules, and that the Missouri Appendix satisfies the requirements of Commission Rules 20 CSR 4240-20.015 by providing the criteria, guidelines, and procedures the Missouri Regulated Utilities will follow when engaging in affiliate transactions.[456]

308. In File No. AO-2017-0360, Empire requested that its CAM be approved by the Commission. That case is currently suspended, as well as other cases involving other utilities' CAMs, pending the outcome of File No. AW-2018-0394, in which the Commission

[453] Ex. 24, Schwartz Direct, page 3.
[454] Ex. 24, Schwartz Direct, page 4.
[455] Ex. 101, Staff Direct Report, page 30.
[456] Ex. 24, Schwartz Direct, page 8.

is considering changes to the Affiliate Transactions Rules for electric and other major utilities.[457]

309. APUC provides benefits to its subsidiaries by providing financing, financial control, legal, executive and strategic management and related services. The services provided by APUC are necessary for all affiliates to have access to capital markets for funding of capital projects and operations.[458]

310. OPC alleges that Empire has no employees and is operated by a non-regulated services company without Commission approval.[459]

311. LUSC employs most of the U.S.-based utility employees, who are assigned to specific utilities.[460]

312. Staff is not aware of any statute, rule or other requirement that obligated Empire to obtain advance approval from the Commission for the employee transfer to LUSC.[461]

313. In File No. EM-2016-0213, Empire provided testimony that LUSC is the legal employer of all United States based utility employees. Thus, Empire's employees are employed by a service company instead of directly by the Empire.[462] The parties to that case were on notice that Empire's employees would be employed by LUSC.

314. The transfer of employees from Empire to LUSC did not necessarily mean that there was any fundamental change in either the nature of the services provided or an increase in its cost to Empire. When Aquila United, Inc. merged with Kansas City

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[457] Ex. 114, Oligschlaeger Rebuttal, pages 3-4.
[458] Ex. 24, Schwartz Direct, page 10.
[459] Ex. 220, Schallenberg Direct, page 6.
[460] Ex. 101, Staff Direct Report, page 30.
[461] Ex. 114, Oligschlaeger Rebuttal, page 8.
[462] Ex. 25, Schwartz Rebuttal, page 6.

Power & Light Company, in subsequent rate cases all labor expense was allocated to Kansas City Power & Light Company employees.[463]

315. Empire is still to a large degree receiving the same services from the same employee positions as it did prior to the LUSC transfer. Accordingly, there should be no appreciable difference in cost between Empire's current receipt of such services from LUSC and Empire having in-house employees perform the services. [464]

316. Providing corporate services to a number of affiliates on a centralized basis, as is done for Empire by the APUC upstream affiliates, is expected to be inherently more cost-effective than having each affiliate, including regulated utilities, provide the services for themselves.[465]

317. For affiliate transactions between regulated and service companies, APUC upstream affiliate charges are calculated at cost, with no profit margin included in the charges to affiliates.[466]

318. Staff supports the concept of centralized provision of services to utilities in the situation where multiple affiliated entities exist under the corporate umbrella, as is the case with Empire.[467]

319. OPC also asserts that Liberty and APUC filed a FERC Form 60, and the costs on the form 60 reports do not match the amounts on Empire's affiliate transaction reports filed with the Commission.[468]

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[463] Ex. 114, Oligschlaeger Rebuttal, page 9.
[464] Ex. 114, Oligschlaeger Rebuttal, page 9.
[465] Ex. 114, Oligschlaeger Rebuttal, page 6.
[466] Ex. 114, Oligschlaeger Rebuttal, page 6.
[467] Ex. 114, Oligschlaeger Rebuttal, page 6.
[468] Ex. 220, Schallenberg Direct, page 8-9.

320. Empire states that there are timing differences between the filings causing different amounts to appear, there are currency conversion rate differences between the two filings, and Empire's Affiliate Transaction Report includes payroll funding and benefits not reflected in the FERC Form 60.[469]

321. OPC alleges that Empire receives allocated cost assignments from LUSC and that because Empire did not competitively bid the goods or services or demonstrate that competitive bidding was neither necessary nor appropriate for these affiliate transactions, it has no ability to determine fair market price, or the fully distributed cost for it to produce the good or service for itself.[470]

322. OPC states that not only do all of Empire's affiliate transactions violate the Commission's affiliate transactions rules but they also violated the conditions of the Merger Stipulation.[471] OPC reviewed Empire's 2018 Affiliate Transactions Report,[472] but OPC points to no specific costs and provides no examples of incurred costs that were imprudent, or violate the Commission's Affiliate Transactions Rules, except for a $90 million affiliate promissory note.

323. OPC contends that a material adjustment should be made to disallow affiliate transactions expenses, but it only provides general and broad allegations of violations of the Affiliate Transactions Rules and does not offer any detailed calculation of what that amount might be.[473]

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[469] Ex. 25, Schwartz Rebuttal, pages 8-9.
[470] Ex. 220, Schallenberg Direct, page 6.
[471] Ex. 220, Schallenberg Direct, page 9.
[472] EX. 220c, Schallenberg Direct, Schedule RES-D-6.
[473] Ex. 114, Oligschlaeger Rebuttal, page 4.

324. Staff disagrees with OPC's assumption that all affiliate transactions present the same level of regulatory concerns, and should be handled in the same manner for ratemaking purposes.[474]

325. Staff differentiates affiliated transactions into three primary categories:

a. An exchange of goods and services between a regulated entity and unregulated affiliate.

b. An exchange of goods and services between two regulated affiliates.

c. Services provided to a regulated affiliate by a nonregulated affiliated service company

326. The first category of affiliated transactions presents greater regulatory concern than the other two categories because the parent company can derive greater profits if a regulated utility overpays for a good or service from an unregulated affiliate [475]

327. Empire's affiliate transactions are almost entirely between Empire and its affiliated service companies.[476]

328. Staff conducted an audit of Empire in the course of this case, including a review of the costs allocated to it from upstream affiliates and found most of those costs to be reasonable. Based on the review, Staff made some adjustments to some of the cost allocations and had a concern with Empire's allocation methodologies.[477]

329. The regulatory concerns when reviewing affiliate transactions include whether the allocated costs reasonably relate to the regulated operations of the utility and are incurred to benefit the utility and its customers, and are not excessive given their intended benefit.[478]

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[474] Ex. 114, Oligschlaeger Rebuttal, page 5.
[475] Ex. 114, Oligschlaeger Rebuttal, page 5.
[476] Ex. 114, Oligschlaeger Rebuttal, page 6.
[477] Ex. 101, Staff Direct Report, pages 29-32.
[478] Ex. 114, Oligschlaeger Rebuttal, page 7.

330. Affiliate transaction rules may be considered to go beyond the parameters of Staff's standard corporate allocations review, if they are interpreted as requiring that market values be determined for all goods and services obtained by utilities from nonregulated service company affiliates.[479]

331. The inherent cost efficiencies embedded within the shared services model employed for Empire, and also commonly found with other utilities, is that transfer of services at cost is generally a reasonable alternative to employment of competitive bidding or other market pricing methodology for services received by regulated utilities from service company affiliates.[480]

332. There have been a reduction in costs in certain functions that Empire previously provided on a stand-alone basis due to transfer of staff to shared service functions. Examples provided by Empire include:[481]

a. For Treasury services, in 2016 prior to its acquisition Empire incurred over $400,000. After the acquisition, the Treasury function became part of the LABS shared services and in 2018 Empire incurred less than $200,000 for Treasury services.

b. For Internal Audit prior to the acquisition, Empire incurred nearly $500,000 for its auditing function, when compared to less than $125,000 after the acquisition.

c. Human Resources functions were transitioned to shared services functions after the acquisition and had incurred approximately $440,000 in 2018, when compared to $700,000 in 2016.

[479] Ex. 114, Oligschlaeger Rebuttal, page 7.
[480] Ex. 114, Oligschlaeger Rebuttal, pages 7-8.
[481] Ex. 24, Schwartz Direct, page 11.

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission finds that the affiliate transactions presented under this case, with the exception of the $90 million promissory note as addressed in issue nine, were prudent and complied with the requirements of Commission Rule 20 CSR 4240-20.015. The Commission does not rely on a presumption of prudence in making this decision. OPC points to no specific costs and provides no examples of incurred costs that were imprudent, or that violate the Commission's Affiliate Transactions Rules, except for a $90 million affiliate promissory note. Therefore, the Commission sees no need for any adjustments to Empire's revenue requirement aside from those identified in issue nine.

The Commission also finds that Empire's interactions with its affiliates should be reviewed as part of the next rate case. Staff should conduct an audit of the various types of affiliate transactions as part of this review and provide testimony to support it findings.

### 18) Riverton 12 O&M Tracker

## Findings of Fact

333. A tracker for Riverton's O&M costs was established in File No. ER-2014-0351. In File No. ER-2016-0023 the tracker was continued because Riverton 12 was converted from a simple cycle to a combined cycle unit so there was no operational history by which to determine an appropriate level of Riverton O&M costs.[482]

334. The Riverton 12 Tracker was established to normalize or smooth costs of the Riverton 12 long-term maintenance agreement.[483]

[482] Ex. 101, Staff Direct Report, page 71.
[483] Ex. 5, Richard Rebuttal, page 4.

335. Operating expenses associated with the Riverton 12 long-term maintenance agreement have increased by $4,789,471 since the tracker was established in Empire's last rate case.[484]

336. Conditions have not changed since the tracker was initiated. Because of the implementation of the SPP Integrated Market, the hours of unit operation have continued to vary from year to year, and the unit starts and trips are inconsistent from year to year. The tracker normalizes those fluctuations and smooths costs.[485]

337. Empire's position is that due to the continued uncertainty of operations and the potential for significant variations in the equivalent operating hours (EOH) charges, the extension of the tracker should be granted in order to continue to protect customers by smoothing the long term maintenance agreement (LTSA) costs.[486]

338. Empire calculated the balance of the Riverton 12 O&M tracker at $13,717,733 as of January 31, 2020, amortized over five years at $2,743,547.[487]

339. Staff calculated the balance of the Riverton 12 O&M tracker at $14,258,325 as of January 31, 2020, amortized over five years at $2,851,665.[488]

340. Staff used a three-year average to calculate O&M expenses for Riverton 12 since it was converted to a combined cycle unit on May 1, 2016. The three-year average O&M expense is $8,133,625 trued-up to January 31, 2020 (before jurisdictional allocation).[489]

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[484] Ex. 4, Richard Corrected Direct, pages 24 and 28.
[485] Ex. 5, Richard Rebuttal, page 5.
[486] Ex. 5, Richard Rebuttal, page 5.
[487] Ex. 63 Riverton Workpapers, and Ex. 7, Richard True-Up Direct, page 13
[488] Ex. 124, Staff's True-Up Accounting Schedules, and Ex. 143, Sarver Surrebuttal True-Up page 9.
[489] Ex. 143, Sarver Surrebuttal True-Up, page 7.

341. Empire calculated the O&M expenses for Riverton 12 as of January 31, 2020, at $8,349,230 using actual rather than averaged amounts.[490]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

Based upon the implementation of the SPP Integrated Market, the fluctuation in the hours of unit operation, and the availability of only three years of O&M information from the time Riverton 12 was converted from a simple cycle to a combined cycle unit, the Commission finds that the Riverton 12 tracker should continue. The Commission determines that the appropriate balance for the Riverton 12 O&M tracker is $14,258,325, which should be amortized over five years at $2,851,665.

The Commission finds that the appropriate amount of O&M expenses to include in the cost of service is $8,133,625, prior to the applying jurisdictional allocations.

**19) Software Maintenance Expense**

**Findings of Fact**

342. Empire has contracts, operating licenses, and agreements with vendors that provide maintenance, upgrades to software, and support for its computer software.[491]

343. Empire calculated software maintenance expense of $924,820.[492] Empire notes that Staff excluded a vendor and that Staff's results should be trued-up to January 31, 2020.[493]

[490] Ex. 64, Riverton Expense True-Up.
[491] Ex. 101, Staff Direct Report, page 80.
[492] Ex. 65, Software Normalized Amount.
[493] Ex. 5, Richard Rebuttal, page 36.

344. Staff determined a software maintenance expense level of $836,858, after adjusting its calculations to include an excluded vendor. Staff annualized the expense for each of the suppliers based on the current rate for each as recorded on the General Ledger as of September 30, 2019. This is not an item that requires true-up.[494]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

The Commission finds that the appropriate normalized level of for software maintenance expense is $836,858.

**20) Advertising Expense**

**Findings of Fact**

345. Staff classifies advertising into five categories: general, safety, institutional, promotional, and political. Institutional and political advertising are always disallowed by Staff. General and safety advertising are always allowed by Staff. Promotional advertising can be allowed to the extent that the utility can provide cost justification for the advertisement.[495]

346. $30,211 of advertising expense was appropriately disallowed from Empire's initial request. Staff provided explanations as to why each item was disallowed. Staff disallowed $1,972 in institutional/goodwill advertising. Institutional/goodwill advertising promotes the company's public image and does not benefit customers. Staff also disallowed $1,800 in invoices that, although paid in the test year, were invoiced in 2017.

[494] Ex. 143, Sarver Surrebuttal True-Up, page 9, and Ex. 101, Staff Direct Report, page 80.
[495] Ex. 101, Staff Direct Report, page 80.

Staff further disallowed $770 in invoices recorded to below the line accounts 182303 and 182318.[496]

347. Empire calculated $155,552 in allowable advertising expense. While Empire made some disallowances, no explanation was provided as to why the disallowances were made.[497]

348. Empire stated that while it did not oppose Staff's adjustments those adjustments should be reduced because the proposed adjustment is on a total company level and the advertising benefits all jurisdictions and should be allocated accordingly.[498]

349. Empire also took issue with some adjustments being disallowed based upon product code assignment, or the description being vague, or an insufficient description on the invoice.[499]

350. Staff used multiple methods to determine whether an advertising invoice was allowed or disallowed. Each advertisement the Company submitted was reviewed to determine its primary message and whether it was recoverable under the categories established in the Commission's ruling in *In re Kansas City Power and Light*. Empire did not provide a copy of the advertisement with the invoice in some instances, so Staff relied on the product code assigned to the advertisement in the general ledger.[500]

**Conclusions of Law**

PP. In the Report and Order in File Nos. EO-85-185 and EO-85-224, Regarding KCP&L Request for a Rate Increase, the Commission discontinued the New York rule regarding advertising and adopted four advertising categories supported by Staff:

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496 Ex. 140, Nieneier Surrebuttal True-Up, page 5.
497 Ex. 66, Advertising Expense Workpapers.
498 Ex. 5, Richard Rebuttal, page 23.
499 Ex. 5, Richard Rebuttal, page 23.
500 Ex. 140, Niemeier Surrebuttal True-Up, page 3.

1. General - informational advertising that is useful in the provision of adequate service

2. Safety - advertising which conveys the ways to safely use electricity and to avoid accidents

3. Promotional - advertising used to encourage or promote the use of electricity

4. Institutional - advertising used to improve the company's public image

The EO-85-185 and EO-85-224 Report and Order states that Staff proposes to allow the costs of all general advertising and reasonable amounts of safety advertising, and the costs associated with promotional advertising if the benefits derived were shown to exceed the costs. It was Staff's further proposal to disallow costs associated with institutional advertising. The Commission added a fifth category of political advertising.[501]

5. Political advertising - does not benefit the ratepayers and is not properly charged to them.

**Decision**

Staff's disallowances regarding advertising are consistent with how the Commission has previously ruled regarding advertising disallowances. The Commission found Staff's analysis most credible. Staff explained the amounts disallowed by category, and gave an overview of its methodology. Staff additionally justified its reasons for relying on invoice category codes for some advertising where Empire failed to provide a copy of the advertisement. The Commission finds that the appropriate amount of advertising to include is $129,196.

[501] In re Kansas City Power and Light Company, 75 P.U.R.4th.

### 21) Customer Service

**Findings of Fact**

351. In the Liberty-Empire merger case, File No. EM-2016-0213, the Commission approved the Merger Stipulation in which Empire and Liberty stated they would strive to meet or exceed the customer service levels currently provided to their customers. The Merger Stipulation also provided that Staff and Empire would meet on a periodic basis to review contact center and other service quality performance. In both 2017 and 2018, Empire's performance fell below pre-merger levels.[502]

352. By Empire's admission it missed its customer service target by 2 percent in 2017, and in 2018, Empire was 16 percent below targeted levels of performance.[503] As of August 2019, Empire was 6 percent below the target.[504]

353. Statistics provided by Empire for September 2019 show an abandoned call rate of 4 percent and an average speed of answer of 44 seconds. Empire has an abandoned call rate goal of 5 percent or less and a goal for answering all calls within 30 seconds.[505]

354. Empire's customer service efforts were hampered by an almost 60 percent turnover in contact center employees, largely due to retirements. Empire currently has increased its staffing above pre-merger levels in the contact center. [506]

355. Turnover attributable to a merger is a common consequence of mergers.[507]

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[502] Ex. 101, Staff Direct Report, page 101.
[503] Ex. 1, Baker Direct, page 12.
[504] Ex. 1, Baker Direct, page 13.
[505] Ex. 101, Staff Direct Report, page 101.
[506] Ex. 1, Baker Direct, pages 12-13.
[507] Ex. 101, Staff Direct Report, page 102.

356. Empire is taking appropriate actions to address the unacceptable contact center performance that began in 2017, subsequent to the merger with Liberty Utilities.[508] However, it is necessary to institute greater oversight regarding customer-service and reporting requirements to prevent situations like this from arising in the future.[509]

357. At the Local Public Hearings conducted in Bolivar, Joplin, and Branson, the most frequent complaint regarding Empire's service involved the number of estimated bills, and the difficulty in addressing estimated bills with Empire.[510]

358. Since the acquisition, Empire's number of estimated bills has increased significantly reaching as high as 25,578 in December of 2019. In the six months before the merger with Liberty Utilities in July of 2017, Empire estimated fewer than 1,000 of its customers' bills each month. Between 2017 and 2018, there was a 654 percent increase in estimated bills and a 293 percent increase between 2017 and 2019. Empire has been able to reduce the estimated bills to 5,658 in January 2020 and 1,179 in February 2020.[511]

359. Empire attributed these high levels of estimated bills to many meter readers leaving their positions for other positions in the company following the announcement about the plan to move to AMI. However, in late 2018, Empire was successful with union contract negotiations, which allowed for the use of contractors for meter reading, which allowed for a reduction in estimated meter reads. Unfortunately, beginning in August 2019, the Meter Reading department had four readers on medical leave at the same time for several months. This, coupled with other factors, led to the Company again experiencing an increase in estimated bills.[512]

[508] Ex. 101, Staff Direct Report, page 102.
[509] Ex. 207, Marke Rebuttal, page 8.
[510] Local Public Hearing transcripts.-Tr. Vol. 3, 4, 5.
[511] Ex. 207, Marke Rebuttal, page 6.
[512] Ex. 3, Baker Surrebuttal, pages 8-9.

360. While the estimated meter reads in the first two months of 2020 continue to be higher than early 2017, they have drastically improved from late 2019. Empire's goal is to read every meter every month. In an effort to meet this goal, Empire has reallocated meter readers to cover service areas that had vacant positions. Additionally, they have allowed employees to work additional overtime. Empire has worked with its meter-reading contractor. The contractor hired an extra person to help keep their routes on schedule, and the contractor will continue to work with the Company to provide additional solutions as needed.[513]

## **Conclusions of Law**

QQ. Commission Rule 20 CSR 4240-13.040 establishes procedures to follow when customers make inquiries of utilities so customer inquiries are handled in a reasonable manner.

> (1) A utility shall adopt procedures which shall ensure the prompt receipt, thorough investigation and, where possible, mutually acceptable resolution of customer inquiries. The utility shall submit the procedures to the commission for approval and the utility shall notify the commission and the public counsel of any substantive changes in these procedures prior to implementation.
>
> (2) A utility shall establish personnel procedures which, at a minimum, ensure that—(A) At all times during normal business hours qualified personnel shall be available and prepared to receive and respond to all customer inquiries, service requests, safety concerns, and complaints.

## **Decision**

The Commission is concerned about Empire's customer service. Much of that concern related to the large number of estimated bills received by Empire's customers and the customer service they receive when trying to understand and resolve issues with

[513] Ex. 3, Baker Surrebuttal, page 9.

estimated bills. Estimated bills have had an effect on customer's perceptions of Empire's customer service. When the large number of estimated bills is combined with the high turnover rate in Empire's contact center, it is a formula for poor customer service. Much of this is likely attributable to the merger, and the Commission is hopeful that this drop in customer service is just temporary.

While the Commission finds that Empire is taking steps to improve its customer service, the Commission believes it is important to monitor Empire's progress related to meter reading and billing. Accordingly, the Commission will order Empire to do the following tasks (originally agreed to by Empire as part of the Agreement) for the years 2020, 2021, and 2022 related to meter reading and billing:

1. Incorporate data into its monthly reports to Commission Staff;

2. Initiate quarterly reports to the Commission Staff and OPC regarding the number of estimated meter readings;

3. Initiate quarterly reports to the Commission Staff and OPC regarding the number of estimated meter readings exceeding three consecutive estimates;

4. Initiate quarterly reports to the Commission Staff and OPC regarding the number of bills with a billing period outside of 26 to 35 days; and

5. Initiate quarterly reports to the Commission Staff and OPC regarding the Company and contract meter reader staffing levels;

6. Evaluate the authorized meter reader staffing level and take action to maintain adequate meter reader staffing levels in order to minimize the number of estimated bills.

7. Company will meet with Staff and OPC to discuss bill redesign possibilities for the future.

8. Ensure that all customers who receive estimated bills for three consecutive months receive the appropriate communication regarding estimated bills and their option to report usage as required by Service and Billing Practices, Rule 20 CSR 4240-13.020(3).

9. Ensure that all customers who receive an adjusted bill due to underestimated usage are offered the appropriate amount of time to pay the amount due on past actual usage as required by Service and Billing Practices, Rule 20 CSR 4240-13.025(1)(C).

10. Evaluate meter-reading practices and take action to ensure that billing periods stay within the required 26 to 35 days, unless permitted by those exceptions listed in the Commission's rules.

11. File notice within this case by September 1, 2020, containing an explanation of the actions the Company has taken to implement the above recommendations related to billing and bill estimates.

**22) Material and Supplies**

**Findings of Fact**

361. Material and Supplies (M&S) are Empire's investment in inventory for items such as spare parts, electric cables, poles, meters, and other items used in daily operations and maintenance activities to maintain Empire's production facilities and electric system. Empire holds a variety of M&S in inventory so the items can be readily available when needed in performing its utility operations.

362. Empire calculates that the appropriate amount of M&S to be included in cost of service is $33,031,612, which represents a 13-month average as of January 31, 2020, for electric inventory only.[514]

363. Staff calculates that the appropriate amount of M&S to be included in cost of service is $32,773,580.[515] This reflects the 13-month average of costs as provided by Empire as of January 31, 2020, after applying the Missouri jurisdictional allocation factor.[516]

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[514] Ex. 10, Palumbo True-Up Direct, page 2, and Ex. 67, Materials and Supplies Workpaper.
[515] Ex. 124, Staff True-up Accounting Schedules, Schedule 02.
[516] Ex. 140, Niemeier Surrebuttal/True-up, page 6.

364. Empire calculates that the appropriate amount to remove from inventory as it relates to Non-Electric items is $67,179, which also represents a 13-month average as of January 31, 2020.[517]

365. Staff calculates the appropriate balance to remove from inventory as it relates to Non-Electric items is $76,714, before Missouri jurisdictional allocations.[518]

366. Clearing accounts are temporary accounts that will be transferred to another account for miscellaneous expenses that need to be allocated to several accounts, such as vehicle maintenance and cell phone expenses. Clearing accounts are not materials or supplies. Staff did not include clearing accounts in its 13-month average.[519]

367. Empire says that clearing accounts should be included in the average because the balances fluctuate during the test year.[520]

## **Conclusions of Law**

No additional Conclusions of Law are required for this issue.

## **Decision**

The Commission finds the evidence presented by Staff most persuasive. The appropriate balance to be included for materials and supplies to be included in the cost of service is $32,773,580, and the appropriate amount to exclude is $76,714. Missouri jurisdictional allocations should be applied to these amounts.

[517] Ex. 10, Palumbo True-Up Direct, page 2, and Ex. 68, Removal of Non-Electric Inventory Workpaper.
[518] Ex. 140, Niemeier Surrebuttal/True-Up, page 6, and Ex. 68, Removal of Non-Electric Inventory Workpaper.
[519] Ex. 140, Niemeier Surrebuttal True-Up, page 6, and Ex. 124, Staff True-Up Accounting Schedules.
[520] Ex. 9, Palumbo Rebuttal, page 2.

**23) Asset Retirement Obligations**

<u>**Findings of Fact**</u>

368. Asset Retirement Obligations (ARO) are obligations associated with a tangible long-lived asset that result from the acquisition, construction, development, or normal operation of a long-lived asset in which the timing or method of settlement is conditional on a future event. An ARO exists when the obligation to perform the asset retirement activity is unconditional even though there may be uncertainty about whether and how and when the obligation will be settled.[521]

369. An ARO is a financial requirement to record currently the costs associated with the future retirement/remediation of a long-lived asset. Therefore, the utility is required to book for financial purposes the current costs to retire a long-lived asset at a date in the future. These costs are then collected over the useful life of the asset.[522]

370. AROs represent one component of costs that are considered in determining the cost of removal component of utility depreciation rates.[523]

371. During the negotiation of this rate case, it was discovered that $9.2 million of claimed ARO costs were already incurred by Empire.[524]

372. What Staff had previously understood to be accrued liabilities booked by Empire for future costs were actually recent cash expenditures. Therefore, Staff changed its position on the rate case treatment of these costs.[525]

373. Staff is generally opposed to rate recovery of AROs. AROs represent one component of costs that are considered in determining the cost of removal component of

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[521] Ex. 4, Richard Corrected Direct, pages 14-15.
[522] Ex. 354, Meyer Supplemental Surrebuttal, page 2.
[523] Ex. 154, Oligschlaeger Sur-Surrebuttal, page 2.
[524] Ex. 354, Meyer Supplemental Surrebuttal, page 3.
[525] Ex. 154, Oligschlaeger Sur-Surrebuttal, page 2.

utility depreciation rates. Cost of removal is allowed to be collected in rates on an ongoing basis in order for the utilities to recover over time the estimated costs of "removing" assets once they are retired and no longer needed to provide service to customers. Allowing rate treatment of AROs would very likely result in double recovery in rates by the utility of certain costs related to retirement of assets.[526]

374. The ARO balance Empire asks the Commission include in rate base is for costs paid to remove asbestos at the Asbury and Riverton generating units, as well as, costs paid to settle obligations for the coal ash ponds at Asbury, Iatan, and Riverton. Empire has not previously recovered these amounts in rates.[527]

375. Staff has verified that the amounts sought in rates by Empire as AROs represent recent cash expenditures, and that the costs were both prudent and necessary.[528]

376. The costs for removal of asbestos at Asbury should be treated as cost of removal and charged against the Asbury accumulated depreciation reserve. Similar treatment should be afforded the costs for working on the Iatan and Asbury ash ponds. For the Riverton ash pond, which has already been retired, the costs were captured in a regulatory asset to be amortized in the next rate case.[529]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

[526] Ex. 154, Oligschlaeger Sur-Surrebuttal, page 2.
[527] Ex. 6, Richard Surrebuttal, pages 3-4 and 6.
[528] Ex. 154, Oligschlaeger Sur-Surrebuttal, page 2.
[529] Ex.354, Meyer Supplemental Surrebuttal, page 3.

## Decision

The Commission has not generally allowed for the recovery of ARO's because without a legal obligation, these future costs were not known and measureable. However, the evidence in this case shows that the costs at issue to remove asbestos at the Asbury and Riverton generating units, as well as, costs paid to settle obligations for the coal ash ponds at Asbury, Iatan, and Riverton are not ARO's. Instead, these costs have already been paid by Empire, but not yet recovered in rates. The cost of removal of asbestos at Asbury and costs associated with the operation of certain ash ponds at Asbury and Iatan shall be charged to the accumulated depreciation reserve of each respective generation facility. However, for the Riverton ash pond, which has already been retired, the costs shall be captured in a regulatory asset to be considered in Empire's next rate case.

### 24) LED Replacement Tracker

## Findings of Fact

377. Empire currently has tariffs for municipal street lighting and its private lighting service.[530]

378. Empire's municipal LED tariff was implemented after a pilot program was conducted to determine the benefits of LED lights compared to high-pressure sodium fixtures.[531]

379. Empire is requesting two deferrals, one to capture the costs associated with the mercury vapor lights replacement program and to track the difference between estimated and actual revenues and costs of the LED light fixtures for municipal lighting

[530] Ex. 33, McGarrah Direct, pages 2 and 7.
[531] Ex. 33, McGarrah Direct, page 3.

customers, and the other to defer and track the same revenues and costs from private lighting customers switching to LED Lighting.[532]

380. LED lights are more efficient, use less energy, last longer, are more durable, and have the ability to operate at lower temperatures than other lighting sources.[533]

381. Empire states that replacing all the mercury vapor lights at once is more efficient and less expensive than replacing the lights individually through attrition. A technician would drive a truck out to each of the 8,500 lights to inspect and determine what type of light is out, whether the failure is a bulb or the fixture and whether the parts are available.[534]

382. Empire proposes to switch all 8,500 municipal mercury vapor lights to LED lights over a 12-18 month time period even if the lights are still in working condition.[535] Empire can control the timing of the replacement of mercury vapor lights.[536]

383. A tracker is a rate mechanism under which the amount of a particular cost of service item incurred by a utility is tracked and compared to the amount of that item currently included in a utility's rates. Any over-recovery or under-recovery of the item in rates compared to actual expenditures is booked to a regulatory asset or liability account, and would be eligible to be included in the utility's rates set in its next general rate proceeding through an amortization to expense.[537]

384. Use of trackers may be justified when the costs are material in nature and the applicable costs:

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[532] Ex. 106, Bolin Rebuttal, page 6.
[533] Ex. 33, McGarrah Direct, page 4.
[534] Ex. 33, McGarrah Direct, pages 6-7.
[535] Ex. 106, Bolin Rebuttal, pages 9-10.
[536] Ex. 106, Bolin Rebuttal, page 9.
[537] Ex. 106, Bolin Rebuttal, page 6.

a. Demonstrate significant fluctuation and up-and-down volatility over time, and for which accurate estimation is difficult;

b. Are new costs for which there is little or no historical experience, and for which accurate estimation is accordingly difficult; and

c. Are imposed upon utilities by Commission rule.[538]

385. Empire is currently collecting in its cost of service depreciation expense and a return on the mercury vapor lights it wishes to replace.[539]

386. If Empire replaces all the mercury vapor lights following the conclusion of this rate case, it would continue to receive rate recovery of depreciation expense and return for those mercury vapor lights until its next rate case which would offset some of the depreciation expense and return Empire would defer for new LED lights.[540]

387. Under a deferral, Empire would get to collect the return and depreciation expense on the new assets that is not currently included in the revenue requirement.[541]

388. Empire witness McGarrah estimated that the cost to install a municipal LED light of minimum size at $372.88, and the cost to install a private light at approximately $240, depending on light size.[542]

389. Staff witness Bolin testified that if Empire replaced all 8,500 municipal mercury vapor lights within a one year time frame, the maximum annual cost of replacement would be approximately $448,195, which is not a material cost for Empire.[543]

[538] Ex. 106, Bolin Rebuttal, page 7.
[539] Ex. 106, Bolin Rebuttal, page 10.
[540] Ex. 106, Bolin Rebuttal, page 10.
[541] Ex. 106, Bolin Rebuttal, page 10.
[542] Ex. 35, McGarrah Surrebuttal, pages 4 and 5.
[543] Ex. 129, Bolin Rebuttal, page 9.

390. If the Company converts all 8,500 mercury vapor lights to LED lighting the annual amount of lost revenue from the municipal lighting customers is estimated to be $127,415, which is also not a material amount to Empire.[544]

391. Staff witness Bolin testified that Empire currently has 5,400 mercury vapor lights in its Missouri private lighting service class. If it replaced all 5,400 of those lights within a one-year time frame, the most the annual cost of replacing the private mercury vapor lights with LED lights would be is approximately $282,333, which is not a material cost for Empire.[545] If the company converts all 5,400 mercury vapor lights in its Missouri private lighting service class to LED lighting, the annual amount of lost revenue from the private lighting customers is estimated to be $79,056, which is not a material amount to Empire.[546]

392. While most of Empire's mercury vapor lights are 30 to 40 years old, they have not failed,[547] and replacement bulbs are still available (although fixtures are not).[548]

## Conclusions of Law

RR. The Commission may "prescribe uniform methods of keeping accounts, records and books to be observed by electrical corporations[.]"[549] Additionally, the Commission may "prescribe by order the accounts in which particular outlays and receipts shall be entered, charged or credited."[550]

[544] Ex. 129, Bolin Rebuttal, page 9.
[545] Ex. 106, Bolin Surrebuttal/True-up, page 8.
[546] Ex. 106, Bolin Surrebuttal/True-up, page 8.
[547] Ex. 35, McGarrah Surrebuttal, page 4.
[548] Ex. 35, McGarrah Surrebuttal, page 2.
[549] Section 393.140(4), RSMo.
[550] Section 393.140(8), RSMo.

## Decision

Empire failed to present adequate or credible evidence to support its request for LED replacement trackers for either municipal lighting or its private lighting service. Staff presented credible evidence that neither the municipal nor the private LED replacement costs were sufficiently material to Empire to justify the extraordinary remedy of a tracker. Additionally, there was no credible evidence that replacement costs fluctuated, were difficult to estimate, or were imposed by a Commission rule.

The Commission is also not convinced that changing from one kind of light to another is a cost for which Empire lacks historical experience, and Empire presented no evidence otherwise. While the Commission recognizes the benefits of such lighting retrofit programs because LED lights are more efficient, use less energy, and last longer, the requirements for establishing a tracker have not been met with the facts presented in this case. The Commission denies Empire's requests for LED replacement trackers.

### 25) May 2011 Tornado Unamortized AAO Balance

## Findings of Fact

393. An AAO is an accounting mechanism that permits deferral of costs from one period to another. The items deferred are booked as an asset rather than an expense, thus improving the financial picture of the utility in question during the deferral period. During a subsequent rate case, the Commission determines what portion, if any, of the deferred amounts will be recovered in rates.[551]

394. In File No. EU-2011-0387, the Commission authorized Empire to defer incremental O&M expenses incurred for the repair, restoration and rebuild activities associated with the May 22, 2011 tornado in Joplin. Empire was also allowed to defer

[551] Ex. 129, Bolin Surrebuttal True-Up, page 2.

depreciation expense and carrying costs associated with the tornado-related capital expenditures. [552]

395. The Commission ordered the Company to begin amortizing the deferral over a ten-year period to start at the earlier of (1) the effective date of new rates implemented in its next general rate case (File No. ER-2012-0345) or next rate complaint case; or (2) June 1, 2013.[553]

396. The AAO permits Empire to accrue a carrying charge equal to its AFUDC rate on its tornado capital additions during the deferral period to offset the lack of a current return on its tornado-related capital additions.[554]

397. The unamortized AAO balance as of January 31, 2020 is $1,274,630.[555]

398. In File No. WR-95-145, the Commission noted that including the unamortized balance of a flooding disaster in rate base would shield the shareholders from the risk of a natural disaster while imposing the risk entirely on the ratepayers.[556]

399. Excluding the unamortized balance from Empire's rate base denies it a return on the investment it made to restore electric service, results in an immediate understatement of Empire's cost of service to Missouri retail customers and is at odds with the Commission's order authorizing the deferral.[557]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

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[552] Ex. 129, Bolin Surrebuttal True-Up, pages 2-3; and Ex. 101, Staff Direct Report, page 53.
[553] Ex. 129, Bolin Surrebuttal True-Up, page 3, and Ex. 101, Staff Direct Report, page 53.
[554] Ex. 129, Bolin Surrebuttal True-Up, page 3.
[555] Ex. 129, Bolin Surrebuttal True-Up, page 3; and Ex. 70, Tornado Regulatory Asset Workpaper.
[556] Ex. 129, Bolin Surrebuttal True-Up, page 4.
[557] Ex. 5, Richard, Rebuttal, page 7.

## Decision

The magnitude of the destruction from the Joplin Tornado was something Empire could neither have prevented nor predicted. After the tornado, Empire made significant investments to restore electric systems to its Missouri retail customers quickly and efficiently. The Commission at that time authorized the deferral of expenses to restore, repair, and rebuild. The Commission finds that it is appropriate that the unamortized AAO Balance for the May 2011 Joplin Tornado be included in rate base.

### 26) Depreciation and Amortization Expense

## Findings of Fact

400. Empire is not requesting to change currently ordered depreciation rates in this case.[558]

401. No new depreciation study was completed for this rate case, and Staff has no objections to the current depreciation study submitted in File No. ER-2016-0023 on October 16, 2015, which meets the requirement of 20 CSR 4240-3.160(1)(A).

402. Staff calculated that the appropriate amount of depreciation expense as of January 31, 2020, is $71,423,882 and the appropriate amount of amortization of electric plant is $3,387,871.[559]

403. Empire calculated that the appropriate amount of depreciation expense as of January 2020, is $71,515,922[560] and the appropriate amount of amortization of electric plant is $3,821,588. [561]

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[558] Ex. 101, Staff Direct Report, page 89.
[559] Ex. 124, Staff True-Up Accounting Schedules.
[560] Ex. 71, Annualized Depreciation Expense.
[561] Ex. 72, Annualized Amortization Expense.



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404. The depreciation amount booked to the clearing account for transportation equipment should be removed from depreciation expense. Those expenditures are charged to construction projects that will eventually be plant in service, so the costs will be recovered through depreciation over the life of the assets.[562]

405. Staff did not provide any evidence as to why it used a depreciation rate of 2.5 percent for FERC accounts 371 and 373 in its True-Up Accounting Schedules.[563]

406. The depreciation rate approved by the Commission in File No. ER-2016-0023 for account 371 is 4.67 percent and for account 373 is 3.33 percent.[564]

**Conclusions of Law**

SS. Section 20 CSR 4240-3.160(1)(A) requires that a depreciation study, database and property unit catalog be submitted with a general rate increase request unless Staff received these items during the three (3) years prior to the rate increase request or before five (5) years have elapsed since last receiving said items.

**Decision**

The Commission finds that the appropriate level of depreciation expense to include in the cost of service is $71,423,882 and the appropriate amount of amortization of electric plant is $3,387,871, applying Staff's jurisdictional allocations except for any adjustments that may be required to correct the depreciation rates for account 371 and account 373. Further, the Commission finds that the depreciation amount booked to the clearing account for transportation equipment should be removed from depreciation expense. The Commission determines that the depreciation rates approved in File No. ER-2016-0023 for account 371 of 4.67 percent and for account 373 of 3.33 percent should be maintained.

[562] Ex. 101, Staff Direct Report, page 90.
[563] Ex. 124, Staff True-Up Accounting Schedules.
[564] Ex. 5, Richard, Rebuttal, page 32.

While Staff agrees that these are the appropriate depreciation rates for accounts 371 and 373, its True-Up Accounting Schedule 5 applies a 2.5 percent depreciation rate to these accounts. Any correction to the True-Up Accounting Schedule should be reflected in the total depreciation expense amount.

**27) Iatan/Plum Point Carrying Costs**

## Findings of Fact

407. In File No. EO-2005-0263, the Commission approved Empire's regulatory plan deferring certain carrying costs associated with the Iatan 1 Air Quality Control Systems (AQCS) investment past its in-service date into Account 182308.[565]The deferral of carrying costs after a project's in-service date is also known as "construction accounting."[566]

408. In the *Report and Order* in KCPL's File No. ER-2010-0355, the Commission disallowed certain costs that had been booked to the Iatan 1 accounts. The effect of these two disallowances reduced the balance of the Iatan 1 AQCS plant balance for all owners, including Empire.[567]

409. In Empire's next general rate proceeding, File No. ER-2012-0345, Staff removed any construction accounting allowances associated with the portion of Iatan 1 AQCS approved disallowances that were allocated to Empire from its rate base and expense amortization calculations.[568]

565 Ex. 101, Staff Direct Report, page 25.
566 Ex. 101, Staff Direct Report, page 25.
567 Ex. 101, Staff Direct Report, pages 25-26.
568 Ex. 101, Staff Direct Report, page 26.

410. In File No. EO-2005-0263, the Commission approved Empire deferring certain "carrying costs" associated with the Iatan 2 generation unit investment past its in-service date in to Account 182332.[569]

411. Staff removed any construction accounting allowances associated with the portion of Iatan 2 disallowances that were allocated to Empire from its rate base and expense amortization calculations. Staff also reduced the balance of Iatan 2 carrying costs by Empire's deferral of fuel and purchased power expense savings it had incurred due to the addition of Iatan 2 to its generating system from the unit's in-service date through June 30, 2012.[570]

412. In File No. ER- 2010-0130, the Commission approved Empire deferring certain "carrying costs" associated with the Plum Point generating unit investment past its in-service date into Account 182331.[571]

413. Based on the results of its Construction Audit and Prudence Review for Plum Point (submitted in File No. ER-2011-0004), Staff recommended one disallowance to Empire's Plum Point plant balances.[572]

414. Staff used the September 30, 2015 balance ($109,533) from the most recent rate proceeding, File No. ER-2016-0023, and the annual amortization expense included in Staff's Accounting Schedules in File No. ER-2012-0345, to determine the unamortized balance to include in rate base.[573]

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[569] Ex. 101, Staff Direct Report, page 26.
[570] Ex. 101, Staff Direct Report page 26.
[571] Ex. 101, Staff Direct Report, page 26.
[572] Ex. 101, Staff Direct Report, page 26.
[573] Ex. 101, Staff Direct Report, pages 26-27.

415. Staff's direct filing calculated Iatan/Plum Point carrying costs through the update period in this case, September 30, 2019. Staff trued up the balances through January 31, 2020.[574]

416. The appropriate level of unamortized Iatan 1 and Iatan 2 carrying costs at January 31, 2020, is Staff's determination of $3,939,778 and $2,148,142 respectively.[575]

417. The appropriate level of amortization for the Iatan/Plum Point carrying costs is Staff's determination of $100,923. [576]

418. Staff's calculation used the September 30, 2015 balance from the most recent rate proceeding, File No. ER-2016-0023, and the annual amortization expense included in Staff's Accounting Schedules in File No. ER-2012-0345, to determine the unamortized balance as of September 30, 2019, those amounts were then trued-up through January 31, 2020.[577]

419. In Empire's File No. ER-2012-0345, Staff recommended amortization of these carrying costs into the cost of service using a composite amortization rate derived from dividing the total depreciation expense for each plant by the total plant balance for each plant. Staff used these composite rates and calculated amortization amounts of $84,729 for Iatan 1 AQCS, $44,828 for Iatan 2, and $1,987 for Plum Point. Staff used the same amortization amounts in this case.[578]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

[574] Ex. 101, Staff Direct Report, pages 26-27 and Ex. 124, Staff True-Up Accounting Schedules.
[575] Ex. 124, Staff True-Up Accounting Schedules.
[576] Ex. 124, Staff True-Up Accounting Schedules.
[577] Ex. 101, Staff Direct Report, page 25-27, and Ex. 124, Staff True-Up Accounting Schedules.
[578] Ex. 101, Staff Direct Report, page 54.

## Decision

The Commission finds that the appropriate amount of carrying costs to include in rate base as of January 31, 2020, is $3,939,778 for Iatan 1, $2,148,142 for Iatan 2, and $100,923 for Plum Point. These amounts reflect construction disallowances ordered in previous cases before this Commission. The appropriate level of amortization expense for the carrying costs are $84,729 for Iatan 1, $44,828 for Iatan 2 and $1,987 for Plum Point.

**28) Incentive Compensation**

## Findings of Fact

420. As a stand-alone company Empire had one incentive plan called the Management Incentive Compensation Program, which offered awards to senior officers for achievement of certain pre-set goals.[579]

421. Post-merger there are four employee incentive plans: the Long Term Incentive Plan (LTIP), and three different short-term incentive plans, the Empire Legacy Bonus/Incentive Plan, the Shared Bonus Plan (SBP) and the Short Term Incentive Plan (STIP). As part of the merger, employees who had Director and above within their title were moved to the Liberty Utilities STIP. The Empire Information Technology team was moved to the Liberty Utilities SBP and STIP.[580]

422. Staff corrected its initial employee incentive adjustments in its surrebuttal true-up testimony after receiving corrected responses to discovery requests from Empire.[581]

[579] Ex. 101, Staff Direct Report, page 66.
[580] Ex. 101, Staff Direct Report, page 66.
[581] Ex. 139, Newkirk Surrebuttal True-Up, page 3.

423. Empires provided Staff with both personal objective achievement percentages and target bonus percentages for all employees with incentive pay for both Empire and its subsidiaries. This enabled Staff to use actual data instead of averages when recreating the incentive pay calculations for each employee.[582]

424. The appropriate level of incentive compensation to include in the cost of service is $1,245,016, the amount determined by Staff.[583]

425. Empire calculated $4,078,229 as incentive compensation to include in the cost of service.[584]

426. The Commission's long-standing precedent has disallowed recovery of employee incentive compensation that is based on shareholder earnings without directly and proportionately benefitting customers.[585]

427. Staff's analysis of Empire's STIP and SBP led to disallowances to eliminate 50 percent of employee incentives associated with the "Our Efficiencies" objective of the parent scorecard. These costs should be assigned to shareholders.[586]

428. Staff also reviewed each divisional scorecard to disallow any incentive metric associated with the performance measure of meeting earnings per share targets or enhancing the value of a utility's stock price.[587]

429. Staff has eliminated stock options associated with Empire's LTIP recognized as an expense in this case consistent with the Commission's *Report and Order* in File No. ER-2006-0315.[588]

[582] Ex. 113, Newkirk Rebuttal, page 2.
[583] Ex. 124, Staff True-Up Direct Accounting Schedules.
[584] Ex. 75, Empire response to DR 0033.1.
[585] Ex. 139, Newkirk Surrebuttal True-Up, page 3.
[586] Ex. 101, Staff Direct Report, page 68.
[587] Ex. 101, Staff Direct Report, page 68.
[588] Ex. 101, Staff Direct Report, page 68.

430. Customers do not appear to receive any real, tangible or measurable benefit from employee incentives awarded based on the company's increased earnings that would outweigh the costs to ratepayers.[589]

431. Incentive goals that boost the value of Empire's stock price benefit Empire's shareholders and not the ratepayers, and those incentives appropriately should not be included in rates.[590]

## Conclusions of Law

TT. The Commission has not generally allowed the recovery of incentive compensation tied to financial metrics in rates because "[t]hose financial incentives seek to reward the company's employees for making their best efforts to improve the company's bottom line. Improvements to the company's bottom line chiefly benefit the company's shareholders, not its ratepayers. Indeed some actions that might benefit a company's bottom line, such as a large rate increase, or the elimination of customer service personnel, might have an adverse effect on ratepayers."[591]

UU. The Commission's historical decisions are represented in its Report and Order in KCPL's rate case in File No. ER-2007-0291. Beginning on page 49 of that Report and Order the Commission said:

> KCPL has the right to tie compensation to [earnings per share]. However, because maximizing [earnings per share] could compromise service to ratepayers, such as by reducing maintenance, the ratepayers should not have to bear that expense. What is more, because KCPL is owned by Great Plains Energy, Inc., and because GPE has an unregulated asset, Strategic Energy L.L.C., KCPL could achieve a high [earnings per share] by ignoring

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[589] Ex. 139, Newkirk Surrebuttal True-Up, page 3.
[590] Ex. 101, Staff Direct Report, page 66.
[591] *In the Matter of Missouri Gas Energy's Tariffs to Implement a General Rate Increase for Natural Gas Service,* File No. GR-2004-0209, Report and Order (issued September 21, 2004), p. 43. See also similar conclusions in *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to implement Its Regulatory Plan*, File No. ER-2007-0291, Report and Order (issued December 6, 2007), p. 49 (the Commission denied Kansas City Power & Light's request to recover compensation tied to earnings per share).

> its Missouri ratepayers in favor of devoting its resources to Strategic Energy. Even KCPL admits it is hard to prove a relationship between earnings per share and customer benefits. Nevertheless, if the method KCPL chooses to compensate employees shows no tangible benefit to Missouri ratepayers, then those costs should be borne by shareholders, and not included in cost of service. [footnotes omitted]

**Decision**

The Commission has traditionally not allowed earnings based compensation to be recovered in rates because those incentives predominantly benefit shareholders and not ratepayers. Incentivizing employees to improve Empire's bottom line aligns the employee interests with the shareholders and not ratepayers. Staff appropriately disallowed the short-term incentive plans because of its earnings per share target, the Long Term Incentive Plan because it is a stock compensation plan, and the Stock Option expenses. The Commission agrees with Staff that those incentive plans are primarily for the benefit of the shareholders and not for the benefit of the ratepayers. The Commission finds that $1,245,016 is the appropriate amount of incentive compensation to include in Empire's cost of service.

### 29) Customer Demand-Side Management Program (DSM)

**Findings of Fact**

432. Empire's Account 182318 contains costs of the Company's customer demand-side management (DSM) programs.[592]

433. Empire states that the rate base amount for the customer DSM program as of January 31, 2020 is $4,269,460 and the appropriate level of amortization expense related to the DSM program is $1,422,715.[593]

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[592] Ex. 101, Staff Direct Report, page 52.
[593] Ex. 76, DSM Workpaper.

434. Staff amortized Empire's costs before its Regulatory Plan ended on June 15, 2011, over ten years. Staff amortized costs incurred after that over a period of six years, consistent with the Commission's Report and Order in File No. ER-2014-0351.[594]

435. Staff removed the amortization of program expenditures from 2007 and 2011 that expired in December 2017, and the amortization of the expenditures from 2008 and 2012 that expired in December 2018, as well as the balance for the years 2009 and 2013 that became fully amortized as of December 2019.[595]

436. After surrebuttal was filed Staff discovered an error in the formula of the supporting workpaper for the calculation of the regulatory asset balance. Staff's corrected workpaper contains the calculations that support its position.[596]

437. The appropriate rate base amount for the customer DSM program trued-up as of January 31, 2020 is $4,267,998 based on Staff's calculations, and the appropriate level of amortization expense related to the customer DSM program is $1,447,308.[597]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

The Commission finds that the appropriate rate base amount for the customer DSM programs is $4,267,998, and the appropriate level of amortization expense related to the customer DSM program is $1,447,308.

[594] Ex. 101, Staff Direct Report, page 52.
[595] Ex. 101, Staff Direct Report, page 52, and Ex. 139, Newkirk Surrebuttal True-Up, page 4.
[596] Ex. 152, Newkirk Additional Evidence.
[597] Ex. 152, Newkirk Additional Evidence.

### 30) Bad Debt Expense

## Findings of Fact

438. Bad debt expense is the portion of retail revenue that Empire is unable to collect from retail customers due to non-payment of bills.[598]

439. The final bill is due 21 days from the statement mailing date. If unpaid, on the second day after the due date, a collection notice is sent advising the customer the account will be turned over to a collection agency if unpaid or suitable arrangements are not made within 10 days. After the 10 days, any accounts that remain unpaid are written off and sent to a collection agency.[599]

440. Empire's bad debt expense fluctuates from year to year.[600]

441. Staff looked at Empire's most recent five years bad debt write-offs that were never collected, and calculated the average uncollectable rate of 0.4016 percent bad debt to revenue. This was applied to Staff's annualized and adjusted test year retail rate revenues to find Empire's normalized bad debt expense.[601]

442. Staff calculated the appropriate level of bad debt expense to include in rates trued-up to January 31, 2020 is $1,910,437.[602]

443. Empire agrees with Staff's methodology for determining the bad debt percentage, but disagrees with the adjusted level of revenues to which Staff applied that percentage.[603]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

[598] Ex. 101, Staff direct Report, page 79.
[599] Ex. 101, Staff direct Report, page 79.
[600] Ex. 101, Staff direct Report, page 79.
[601] Ex. 101, Staff direct Report, page 79.
[602] Ex. 124, Staff's True-Up Accounting Schedules.
[603] Ex. 5, Richard Rebuttal, page 21.

## Decision

Both Empire and Staff arrived at similar uncollectable expense ratios. It appears the main discrepancy between the parties' bad debt expense calculations is dependent upon the level of revenue. The Commission finds that a five-year average is the most appropriate method to calculate the uncollectable rate, and that Staff's annualized and adjusted test year retail rate revenues are reasonable. Therefore, the Commission determines that the appropriate level of Bad Debt Expense to include in Empire's cost of service is $1,910,437.

**31) Retail Revenue**

## Findings of Fact

444. Operating revenues are composed of retail rate revenue and other operating revenue. Retail rate revenue is defined as test year rate revenues consisting solely of the revenues derived from the current rates Empire charges for providing electric service to its Missouri retail customers (i.e., native load and customer charges).[604]

445. Revenues from the FAC represent collections or refunds of prior period fuel costs and are excluded in determining the annualized level of ongoing rate revenues.[605]

446. Staff eliminated unbilled revenue from its determination of revenue requirement to ensure only 365 days of revenue are included and to reflect revenues on an "as billed" basis.[606] The recording of unbilled revenue on the books of Empire recognizes sales of electricity that have occurred but have not yet been billed to the customer.[607] It is necessary to remove unbilled revenue in order to reach an accurate

[604] Ex. 101, Staff Direct Report, page 35.
[605] Ex. 101, Staff Direct Report, page 35.
[606] Ex. 101, Staff Direct Report, page 49.
[607] Ex. 101, Staff Direct Report, page 49.

revenue requirement based on electricity sales actually collected from Missouri customers.[608]

447. Staff removed the FAC revenues from the test year revenues.[609]

448. Franchise taxes are removed from revenue requirement because city franchise tax is not a revenue source for Empire.[610] It is a municipal tax Empire is obligated to collect and remit to the various municipalities where the Company provides electric service. Generally, there is no impact on Empire's earnings related to the collection of city franchise taxes because this revenue is offset by an equal amount of expense.[611]

449. Empire's states that Staff's process violated the fundamental matching principle in ratemaking in regards to adjustments made to FAC revenues, unbilled revenue and franchise tax revenue.[612]

450. In order to have appropriate matching when normalizing or annualizing revenues or expenses, a common date is used across the board. However, in the case of complete disallowance, the amount is not trued-up past the test year because it is not necessary in order to set an account to zero. No matter what balances would be reflected in the update period or true-up period, it is the test year that is adjusted in the EMS run. So for that reason, as done by Staff, a negative adjustment should be made equal to test year amounts in order to remove these revenues from the revenue accounts.[613]

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[608] Ex. 101, Staff Direct Report, pages 49-50.
[609] Ex. 101, Staff Direct Report, page 49.
[610] Ex. 8, Palumbo Direct, pages. 3-4, and Ex. 101, Staff Direct Report, page 50.
[611] Ex. 8, Palumbo Direct, pages. 3-4; and Ex. 101, Staff Direct Report, page 50.
[612] Ex. 5, Richard Rebuttal, page 12.
[613] Ex. 139, Newkirk Surrebuttal True-Up, pages 1-2.

451. The appropriate adjustments to be removed from retail revenues are the total amounts recorded in the general ledger for the test year: [614] unbilled revenues, $6,391,485; franchise tax revenues, $9,923,350; and FAC revenues, $17,047,207. Since these accounts are only pass-through accounts, Staff's adjustment will zero out each account and have no effect on the cost of service.[615]

452. Staff adjusted actual billing determinants to equal the normalized and annualized monthly kWh using the relationship between actual average usage per customer and normalized and annualized average usage per customer. Staff also used the relationship between percentage of usage priced in the first rate block and the second rate block to distribute normalized and annualized monthly kWh to the rate blocks for rate classes Residential Service (RG), Commercial Service (CB) and Small Heating Service (SH). This calculation resulted in normalized usage by rate block, which was then converted to total normalized and annualized revenues by multiplying rate block usage by the appropriate rates. The GP and Total Electric Building Service (TEB) class billing units were similarly adjusted; however, the rate classes were subdivided by voltage with separate normalization and annualization adjustments being applied to each voltage level.[616]

453. The appropriate level of billing determinants to be used in the calculation of retail rate revenue for the test year are included in the true-up workpapers of Michelle Bocklage[617] and Byron Murray[618], and the level of retail revenue is provided in Staff's True-Up Accounting Schedules.[619]

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[614] Ex. 124, Staff True-Up Accounting Schedules, Schedule 10, page 1
[615] Ex. 101, Staff Direct Report, pages 49-51, and Ex. 139, Newkirk Surrebuttal True-up, pages. 1-2.
[616] Ex. 101, Staff Direct Report, page 37.
[617] Ex. 147, Bocklage Supporting Evidence.
[618] Ex. 151, Murray Supporting Evidence.
[619] Ex. 124, Staff True-Up Accounting Schedules.

454. The billing adjustments should be trued up to January 31, 2020; with the exception of retail revenue for unbilled revenue, franchise tax revenue, and FAC revenue. The excepted amounts should not be trued up but should be left at test year amounts.[620]

**Conclusions of Law**

No additional conclusions of law are necessary.

**Decision**

The difference between Empire's and Staff's position on these issues is based on Empire's use of balances trued-up through January 31, 2020, while Staff used test year amounts through September 30, 2019. According to Empire, updating these amounts is necessary in order to maintain a proper matching of the rate components. The Commission was persuaded by Staff's explanation that unbilled revenues, franchise tax revenue, and FAC revenues, are pass-through accounts and Staff's adjustment will zero out each account so that it has no effect on cost of service. Thus, with the exceptions of retail revenue for unbilled revenue, franchise tax revenue and FAC revenue, billing adjustments should be trued-up to January 31, 2020, in order to maintain the appropriate matching. However, the adjustments to retail revenue for unbilled revenue, franchise tax revenue and FAC revenue should not be trued up but should be left at test year amounts.

The Commission was also persuaded that Staff's adjustments represent the appropriate amounts to be removed from retail revenues. Those amounts are: unbilled revenues, $6,391,485; franchise tax revenues, $9,923,350; and FAC revenues,

[620] Ex. 139, Newkirk Surrebuttal True-up, page 2.

$17,047,207.[621] These are the total amounts recorded in the general ledger for the test year.[622]

The Commission further determines that the appropriate level of billing determinants to be used in the calculation of retail rate revenue for the test year are included in the true-up workpapers of Michelle Bocklage[623] and Byron Murray,[624] and the appropriate level of retail revenue is provided in Staff's True-Up Accounting Schedules.[625]

**32) Other Revenue**

**Findings of Fact**

455. Other operating revenue includes revenues from such items as forfeited discounts, reconnect charges, rent from electric property, and other miscellaneous charges.[626]

456. Coal fly ash is a byproduct created as a result of the burning of coal in generating stations to produce electricity. Fly ash has a number of possible industrial uses, primarily as an ingredient in concrete products. Over the past several years, Empire has been selling its fly ash to several different industrial companies to be used in concrete. By recycling fly ash, Empire receives revenue and provides positive environmental benefits.[627]

457. Empire's miscellaneous other revenues consist of forfeited discounts, rents from property, reconnect, and surge arrester fees. Staff's analysis reflected a review of

[621] Ex. 101, Staff Direct Report, pages 49-51, and Ex. 139, Newkirk Surrebuttal, pages 1-2.
[622] Ex. 101, Staff Direct Report, pages 49-51, and Ex. 139, Newkirk Surrebuttal, pages. 1-2.
[623] Ex. 147, Bocklage Supporting Evidence.
[624] Ex. 151, Murray Supporting Evidence.
[625] Ex. 124, Staff True-Up Accounting Schedules.
[626] Ex. 101, Staff Direct Report, page 35.
[627] Ex. 101, Staff Direct Report, pages 50-51.

these revenue levels over a three-year period ending September 30, 2019. Based upon Staff's review, the miscellaneous revenue levels at a 12-month period ending September 30, 2019, appear reasonable for inclusion in customer cost of service.[628]

458. Empire agreed with or did not oppose adjustments proposed by Staff in their Direct Report for rent revenue, fly ash revenues, and miscellaneous revenues.[629] Empire updated its rent revenues balance to September 30, 2019, as recommended by Staff witness Caroline Newkirk in Staff's Direct Report.[630] The other electric revenues were normalized to a three-year average as of September 30, 2019, while the fly ash revenues were adjusted.[631]

459. With the additional data provided as a part of true-up, Staff adjusted its date ranges to full calendar years instead of the mid-year ranges, which were previously used. Staff used the 12-month period ending December 31st for 2017, 2018, and 2019 to analyze trends in the "other revenue" data. After analyzing the trends in the data, Staff decided to use a three-year average for rent revenue, fly ash revenue, and other electric revenue.[632]Empire showed that the appropriate normalized amount of rent revenues is $1,026,462,[633] other electric revenues is $354,638,[634] and fly ash revenues that should be included in the cost of service is $36,107.[635]

**Conclusions of Law**

No additional conclusions of law are needed.

[628] Ex. 101, Staff Direct Report, page 51.
[629] Ex. 5, Richard Rebuttal, page 37.
[630] Ex. 7, Richard True-Up Direct, pages 9 and11; and Ex. 81, Rent Revenues Workpaper,
[631] Ex. 7, Richard True-Up Direct, pages 9 and 11, Ex. 82, Other Revenues Workpaper, and Ex. 83, Fly Ash Revenues Workpaper.
[632] Ex.139, Newkirk Surrebuttal/True-up, page 4.
[633] Ex. 81, Rent Revenues Workpaper.
[634] Ex. 82, Other Revenues Workpaper,
[635] Ex. 83, Fly Ash Revenues Workpaper.

## Decision

The Commission finds that Empire's approach is more consistent with the approach used in other calculations. Empire did not oppose Staff's adjustments for rent revenues, other electric revenues, or fly ash revenues as outlined in Staff's Direct Report. Empire appropriately updated the rent revenues balance to September 30, 2019, and normalized the other revenues to a three-year average as of September 30, 2019 as initially suggested by Staff. Empire provided the workpapers of its witness showing that the appropriate normalized amount of rent revenues is $1,026,462, other electric revenues is $354,638, and the level of fly ash revenues that should be included in the cost of service is $36,107.

**33) Tax Cut and Jobs Act Revenue**

## Findings of Fact

460. Test year rate revenues do not reflect the full amount of the reduction to Empire's rates ordered by the Commission in File No. ER-2018-0366, from the TCJA.[636]

461. Test year revenues were overstated by the difference between the amount that was actually billed to customers during the test year and the amount that would have been billed if the federal tax rate reduction had been in effect throughout the entire test year.[637]

462. Staff proposes an adjustment to remove the income tax impact to revenues for each rate class by multiplying the actual test year kWh for the months of April 2018 through August 2018 by the appropriate class' tax credit as established in File No. ER-2018-0366.[638]

[636] Ex. 101, Staff Direct Report, page 49.
[637] Ex. 101, Staff Direct Report, page 49.
[638] Ex. 101, Staff Direct Report, page 49.

463. The appropriate amount of TCJA revenue to remove from test year revenues is $7,760,076,[639] which represents the sum of the adjustment to all Empire rate classes.[640]

**Conclusions of Law**

No additional conclusions of law are necessary.

**Decision**

The evidence shows that test year revenues, beginning April 1, 2018, were overstated because the TCJA was not recognized in Empire electric rates until September 1, 2018. The Commission determines that the test year revenue amounts were overstated by $7,760,076, which should be removed from test year revenues to properly reflect the current income tax rate for the entire test year. The Commission agrees with Staff's recommended adjustment to remove the income tax impact to revenues for each rate class by multiplying the actual test year kWh for the months of April 2018 through August 2018 by the appropriate class' tax credit. The Commission has already found in issue 12 that the amounts deferred for the stub period shall be amortized as a reduction to Empire's total amortization expense over five years with no rate base offset for the unamortized amount.

## 34) Property Insurance

**Findings of Fact**

464. Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences.[641]

[639] Ex. 102, Staff Direct Accounting Schedules, and Ex. 124, Staff True-Up Accounting Schedules.
[640] Ex. 102, Staff Direct Accounting Schedules, and Ex. 124, Staff True-Up Accounting Schedules.
[641] Staff's Cost of Service Report, Ex. 101, pages 77-78.

465. Utilities, like non-regulated entities, routinely incur insurance expense to minimize their liability, and potentially that of their customers, associated with unanticipated losses.[642]

466. Staff annualized Empire's insurance expense.[643]

467. Staff made an adjustment to its direct filing to include increases to Empire's portion of the 2019-2020 property insurance premium by $934,813.[644]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

The Commission finds Staff's determination of property insurance expense to be included in Empire's cost of service on a Missouri jurisdictional basis appropriate.

[642] Staff's Cost of Service Report, Ex. 101, pages 77-78.
[643] Staff's Cost of Service Report, Ex. 101, page 78.
[644] Ex. 125, Arabian Surrebuttal True-Up, page 3.

**35) Injuries and Damages**

## Findings of Fact

468. Empire maintains workers' compensation insurance for the benefit of its employees.[645]

469. The workers' compensation adjustment proposed by Staff annualizes this expense based upon the premiums in effect at July 2019 to reflect an ongoing and normal expense level for Empire.[646]

470. From time to time, claimants sue Empire seeking payment of damages. If Empire loses the lawsuit, Empire will likely make a payout to the aggrieved party. Alternatively, it may choose to enter in to an out-of-court settlement, also resulting in a payout.[647]

471. To determine a normalized level of this expense, Staff used a five-year average of actual injuries and damages and workers' compensation payments in its cost of service report, instead of relying upon accounting estimates. Staff applied an allocation of 50 percent to the five-year average of actual payments made for injuries and damages[648].

472. The allocation of 50 percent represents the electric expense portion of the payments. The remaining 50 percent of the payments are allocated to the Company's construction, water operations and below-the-line activities.[649]

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[645] Ex. 101, Staff Cost of Service Report, page 81.
[646] Ex. 101, Staff Cost of Service Report, page 81.
[647] Ex. 101, Staff Cost of Service Report, page 81.
[648] Ex. 101, Staff Cost of Service Report, page 81.
[649] Ex. 101, Staff Cost of Service Report, page 81.

473. Below the line refers to line items in the income statement that do not directly impact a company's reported profits.[650]

474. A five-year average of actual payments was used to normalize this expense, because Staff's analysis shows a considerable fluctuation in the annual amount of payments from one year to the next.[651]

475. The appropriate amount of injuries and damages expense to include in the cost of service is $312,562 (total company).[652]

476. Empire annualized its' insurance expense based on new insurance premiums that went into effect after the test year. This adjustment also normalized the test year level of injuries and damages claims and workers' compensation payments by utilizing a five-year average of actual payments.[653]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

Both Empire and Staff agree on the total company injuries and damages expense to be included in the cost of service. The Commission finds that $312,562 is the appropriate amount of injuries and damages expense, total company, to include in the cost of service.

[650] Ex. 101, Staff Cost of Service Report, page 81.
[651] Ex. 101, Staff Cost of Service Report, page 81.
[652] Ex, 86, Richard workpaper.
[653] Ex. 7, Richard True-Up Direct, page 16.

### 36) Payroll and Overtime

**Findings of Fact**

477. Staff made adjustments to Empire's test year payroll expense to reflect annualized levels of payroll, payroll taxes, and 401(k) benefit costs as of January 31, 2020, as detailed in Staff's Direct Cost of Service Report and True-Up testimony.[654]

478. Staff's test year total payroll includes all the components of payroll expense (regular payroll, overtime payroll and incentive compensation).[655] Staff calculated regular payroll and overtime separately from incentive compensation. Staff independently calculated an annualized level of incentive compensation to include in the cost of service, and therefore made an adjustment to add this number into the cost of service.[656]

479. Staff made several adjustments to its initial filing to correct employee counts through the true-up period, January 31, 2020.[657]

480. Staff made adjustments to remove all incentive compensation that occurred in the test year. Staff then made a further adjustment adding the appropriate amount of incentive compensation back into the cost of service.[658]

481. Staff calculated a reasonable overtime payroll level for Empire by multiplying an overtime percentage computed for the non-union and union employees based on a two-year average of overtime hours that actually occurred by the current rate paid for overtime as of September 30, 2019, then divided that amount by Staff's pro forma base payroll amount.[659]

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[654] Ex. 125, Arabian Surrebuttal True-Up, page 3; and Ex. 101, Staff Cost of Service Report, page 62.
[655] Ex. 129, Bolin Surrebuttal, page 4.
[656] Ex. 129, Bolin Surrebuttal, page 4.
[657] Ex. 125 Arabian Surrebuttal True-Up, pages. 2-3.
[658] Ex. 129, Bolin Surrebuttal, page 4.
[659] Ex. 101, Staff Direct Report, page 62.

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission finds that Staff's methodology to determine the appropriate test year amount updated through the true-up period of January 31, 2020 for total payroll, including overtime expense, to be appropriate for inclusion in Empire's cost of service.

### 37) Retention Bonuses

## Findings of Fact

482. There is a very high demand for employees that have the unique skillset of journeyman lineman, who support efforts of increased reliability, infrastructure upgrades, and increased responsiveness to customer requests. As a result of the increased competition, utilities, including Empire, have struggled to hire and retain the desired number of journeyman lineman.[660]

483. As a result of this high demand, utility contract companies are now willing to offer high premium pay and other benefits, including daily per diems in an effort to meet their workforce needs. In most cases, employees have been able to double and even triple their compensation.[661]

484. Empire's planned to offer monthly retention bonuses of $1,500 until the increased competitive job market for lineman subsides. Empire plans to also promote this incentive externally to attract lineman. Empire also plans on offering this retention bonus to retain existing staff with lineman skills currently in other roles,[662]

[660] Ex. 39, Westfall Direct, page 12.
[661] Ex. 39, Westfall Direct, page 12.
[662] Ex. 39, Westfall Direct, page 13.

485. Empire has requested to include an annualized amount of retention bonuses paid to linemen and other qualified employees that started after the test year in rates.[663]

486. Prior to implementing the lineman retention program starting with the September 2019 pay period, Empire lost 16 journeymen linemen between March and August of 2019.[664]

487. Now that the retention program has been implemented, Empire states that retention efforts have been successful. Empire has been able to keep qualified personnel, having only lost two lineman since the roll out of the retention program. It has also assisted with Empire's recruitment efforts to replace the employees it had lost.[665]

488. Empire urges the Commission to include $1,021,080, for journeyman lineman retention bonuses in its cost of service.[666]

489. Staff included amounts considered to be known and measurable in its direct case as of September 30, 2019, the end of the update period. This predates the retention program, which had not yet been implemented.[667]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

Empire has described the shortage of journeyman lineman, and has explained that it has had difficulty in attracting and retaining qualified employees for this position. The Commission finds Empire's testimony regarding the shortage of journeyman lineman

[663] Ex. 7, Richards True-Up Direct, pages 13 and 21.
[664] Ex. 40, Westfall True-Up Direct, page 3.
[665] Ex. 40, Westfall True-Up Direct, page 3.
[666] Ex. 88, Retention Workpaper and Ex. 7, Richards True-Up Direct, page 13.
[667] Ex. 125, Arabian Surrebuttal True-Up, page 2.

credible. Hiring and retaining qualified linemen is important to Empire being able to provide safe and adequate service. Accordingly, the Commission finds that $1,021,080, should be included in Empire's cost of service for its lineman retention program.

### 38) Employee Benefits

**Findings of Fact**

490. Empire offers its employees dental, vision, healthcare, and life insurance benefits, which are included in Account 926.[668]

491. Staff analyzed Empire's employee benefit costs included in its general ledger. Staff annualized each expense by examining the individual costs over a 36-month period to determine the appropriate amount to include for each expense. A three-year average through the update period was performed to annualize these expenses ending September 30, 2019.[669]

492. Empire trued up the test year medical, dental, and vision claim expense accounts to the balances at January 31, 2020.[670]

**Conclusions of Law**

No additional Conclusions of Law are required for this issue.

**Decision**

Based on the evidence, the Commission finds that Staff's three-year average to annualize employee benefits through September 30, 2019 is the appropriate method to use to determine the level of employee benefits to include in the cost of service.

[668] Ex. 101, Staff Direct Report, page 63.
[669] Ex. 101, Staff Direct Report, page 63, Ex. 102, Staff Direct Accounting Schedules, and Ex. 124, Staff True-Up Accounting Schedules.
[670] Ex. 7, Richard True-Up Direct, page 15, and Ex. 89, Medical Dental Vision Workpaper

## 39) Property Taxes

**Findings of Fact**

493. Utility companies are required to file a valuation of their utility property with their respective taxing authorities at the beginning of each assessment year, which is January 1st. Based on the information provided by the utility, the taxing authority will in turn send the company its "assessed values" for every category of the company's property.[671]

494. The taxing authority issues a property tax bill to the utility late in the year which is due no later than December 31st.[672]

495. Staff's calculation is based upon the last known actual amount of property taxes paid by Empire and the plant-in-service associated with the property tax payment.[673]

496. To appropriately calculate the overall property tax amount for Empire, the amount of Empire's share of the Plum Point plant was subtracted from total plant in service. The owners of Plum Point have agreed to make an annual Payment In Lieu of Taxes (PILOT) instead of paying property taxes. The set amount of PILOT taxes that Empire has agreed to pay for Plum Point was then added to the annualized property tax calculation to determine the total property tax adjustment.[674]

497. The appropriate amount of property tax expense is $25,138,294. Staff determined this annualized level by applying Empire's tax rate to plant in service balances

[671] Ex. 101, Staff's Cost of Service Report, pages 78-79.
[672] Ex. 127, Surrebuttal/True-Up Testimony of Courtney Barron, page 2.
[673] Ex. 127, Surrebuttal/True-Up Testimony of Courtney Barron, page 2.
[674] Ex. 101, Staff's Cost of Service Report, pages 78-79.

as of December 31, 2019, which are the most current known and measurable balances used in the property tax assessment process.[675]

498. The proper method to calculate the property tax to be included in cost of service is Staff's method. Staff calculated the property rate by dividing the 2019 property taxes paid by the December 31, 2018 total property. This property tax rate was then applied to the total property as of December 31, 2019 to determine annualized property tax. Not included in the property tax calculation is the 2019 Plum Point PILOT paid, Staff added this to the annualized property tax to determine the total annualized property tax.[676]

499. Staff updated property tax expense to reflect plant-in-service as of December 31, 2019. The ratio of property taxes paid at year-end 2019 to the balance of plant-in service as of January 1, 2019 was applied by Staff to the December 31, 2019 plant-in-service balance.[677]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission finds that $25,138,294 (after the jurisdictional allocation factor is applied) is the appropriate amount of property tax to include in the cost of service. The Commission additionally finds that Staff's method of calculating property tax is reasonable.

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[675]Ex. 101, Staff's Cost of Service Report, pages. 78-79; Ex. 127, Barron Surrebuttal/True-up , pages. 1-3; and Ex. 124, Staff True-up Accounting Schedules.
[676] Ex. 101, Staff's Direct Report, pages 78-79; Ex. 127, Barron Surrebuttal/True-up *T*, pages 1-3.
[677] Ex. 127, Barron Surrebuttal/True-up, page 3.

## 40) Dues and Donations

### Findings of Fact

500. Edison Electric Institute (EEI) is an association of investor-owned electric utilities and industrial affiliates, whose primary function is to represent the interests of its members in the legislative and regulatory arenas, which includes lobbying activities.[678]

501. Staff excluded EEI dues totaling $179,693, because Empire failed to quantify the benefit of its participation in this organization to the ratepayers and shareholders.[679]

502. In addition, Staff disallowed other dues and donations, which included those related to country clubs, national and state level chamber of commerce, and alumni associations. Allowing Empire to recover these expenses through rates would cause ratepayers to involuntarily contribute to these organizations.[680]

### Conclusions of Law

No additional Conclusions of Law are required for this issue.

### Decision

The Commission finds that dues and donations to EEI and the other dues and donations identified by Staff in its Direct Report, which included those related to country clubs, national and state level chamber of commerce, and alumni associations, should be excluded from the cost of service because there is no direct benefit to ratepayers.

[678] Ex. 127, Barron Surrebuttal/True-up, page 3.
[679] Ex. 101, Staff's Direct Report, page 77.
[680] Ex. 101, Staff's Direct Report, page 76.

**41) Outside Services**

## Findings of Fact

503. Various outside (independent) contractors and vendors provide legal, auditing, and other services to Empire to carry out its operational activities as needed.[681]

504. Staff reviewed Empire's outside services expenses booked to Accounts 923045 and 923047 for the test year through the update period ending September 30, 2019. Staff normalized the amounts of outside services by calculating a five-year average of incurred costs for these accounts in the amount of $2,326,254.[682]

505. Staff subtracted the five-year average of incurred costs from the test year total to determine the adjustment. 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.[683]

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

The Commission finds that $2,326,254 is the appropriate amount of outside services to be included in the cost of service from Accounts 923045 and 923047. The Commission further determines that Staff's jurisdictional allocations should be applied.

[681] Ex. 101, Staff Direct Report, page 82.
[682] Ex. 101, Staff Direct Report, p. 82.
[683] Ex. 101, Staff Direct Report, page 82.

## 42) Common Property Removed from Plant and Accumulated Depreciation

### Findings of Fact

506. Empire records its water, non-utility operating, Empire District Gas, fibercom, MO water, and MO Midstates gas general plant in service balances on its electric books.[684]

507. Some common plant assets on Empire's books are related to non-electric service and should be removed.[685]

508. Staff applied an allocation factor to the entire general plant balances, FERC Accounts 389-398, instead of applying the allocation factor only to those specific assets within the plant accounts that are shared. Those accounts do not just include electric plant but also include common plant that serves other regulated and unregulated business.[686]

509. Empire made adjustments to remove a portion of common plant utilized by other businesses, which includes buildings such as the Joplin Corporate Office, the Joplin Kodiak Operations office and the Ozark Call Center. Then it applied a jurisdictional allocation factor to all remaining general plant.[687]

510. Prior to the application of the jurisdiction factors the total company amounts are $5,724,752 for removal of common property from plant in service, and $3,330,005, for accumulated depreciation as of the end of the true-up period ending January 31, 2020.[688]

### Conclusions of Law

No additional Conclusions of Law are required for this issue.

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[684] Ex. 101, Staff Direct Report, page 19.
[685] Ex. 4, Richard Corrected Direct, page 11.
[686] Ex. 5, Richard Rebuttal, page 3.
[687] Ex. 5, Richard Rebuttal, page 3.
[688] Ex. 93, Common Property True-Up Workpaper.

## Decision

The Commission finds that Empire's method of calculating removal of common property from plant in service and the corresponding accumulated depreciation is the appropriate method. Staff erred because FERC Accounts 389-398 are not all common plant. Therefore, the Commission concludes that $5,724,752 is the correct amount for removal of common property from plant in service, and $3,330,005, is the correct corresponding amount for accumulated depreciation. Staff's jurisdictional allocation factors should be applied to those amounts.

### 43) File No. EM-2016-0213 Commission-ordered conditions

Some parties have questioned Empire's compliance with conditions A.4, A.5, A.6, and G.3 contained in the Merger Stipulation approved by the Commission in File No. EM-2016-0213. Compliance with conditions A.4, A.5, and A.6, regarding cost of capital, capital structure, and affiliate transactions, are addressed elsewhere in this Report and Order. Consequently, because those issues have already been addressed, no additional findings of fact or conclusions of law are necessary, and no relief need be granted beyond what has been determined in other issues.

Empire's compliance with condition G.3, involving access to records, has not been otherwise addressed and the Commission will address that condition here.

## Findings of Fact

511. In the Merger Stipulation approved by the Commission in File No. EM-2016-0123, the parties were aware of the potential impact APUC's business and financing strategies might have on Empire's capital structure, and cost of capital.[689]

[689] Ex. 210, Murray Direct, page 20.

512. The Merger Stipulation contained conditions regarding records access that the joint applicants, Empire and Liberty, agreed to follow.[690]

513. Condition G.3 of the Access to Records Conditions states: Empire shall provide Staff and OPC access to and copies of, if requested by Staff or OPC, the complete Liberty Utilities Co, LU Central and Empire Board of Directors' meeting minutes, including all agendas and related information distributed in advance of the meeting, presentations and handouts, provided that privileged information shall continue to be subject to protection from disclosure and Empire shall continue to have the right to object to the provision of such information on relevancy grounds.[691]

514. OPC's witness Murray states that there were discovery problems related to withholding of APUC and LUCo materials, such as Board of Director documents and affiliate financing transaction materials.[692]

515. Staff was provided access to Board of Director documents in response to data request No. 0009.[693]

516. OPC requested all affiliate loan agreements for all of the companies that may be involved in raising financing to capitalize LUCo's capital structure. Empire objected that the information was irrelevant.[694]

517. OPC requested information on how recent economic and capital market events may impact APUC's investment plans for Empire and/or financing plans. Empire objected that the information was irrelevant because it was outside the test year.[695]

[690] Order Approving Stipulations and Agreements and Authorizing Merger Transaction, Issued September 7, 2016.
[691] Order Approving Stipulations and Agreements and Authorizing Merger Transaction, Appendix to Attachment A, Issued September 7, 2016.
[692] Ex. 211, Murray Rebuttal, page 6.
[693] Ex. 153, Empire response to Staff data request 0009.
[694] Ex. 212, Murray Surrebuttal True-Up, page14.
[695] Ex. 212, Murray Surrebuttal True-Up, page 8.

518. No party in this case sought to compel discovery.

## Conclusions of Law

No additional Conclusions of Law are required for this issue.

## Decision

Condition G.3 of the Merger Stipulation, Access to Records Conditions, states that Empire shall provide Staff and OPC access to the complete LUCo and Empire Directors' meeting minutes. It also states that Empire may object for relevancy. OPC's witness Murray testified regarding the information Empire objected to for relevancy. Empire is within its right to object under condition G.3 for relevancy. If OPC believed that the requested information was relevant it should have asked the Commission to compel Empire to produce that information. It did not. The Commission received no motions to compel discovery in this case. The Commission finds that Empire complied with condition G.3, because it provided board of director information to Staff in response to Staff's request, and timely objected to OPC's requests based upon relevancy.

## Decision Summary

In making this decision as described above, the Commission has considered the positions and arguments of all of the parties. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the material was not dispositive of this decision.

Additionally, Empire provides safe and adequate service, and the Commission concludes, based upon its review of the whole record, that the rates approved as a result of this order support the provision of safe and adequate service. The revenue requirement authorized by the Commission is no more than what is sufficient to keep Empire's utility plants in proper repair for effective public service and provide to Empire's investors an opportunity to earn a reasonable return upon funds invested.

By statute, orders of the Commission become effective in thirty days, unless the Commission establishes a different effective date.[696] In order that this case can proceed expeditiously, the Commission will make this order effective on July 11, 2020 to match the date to which Empire tariff has been suspended.

**THE COMMISSION ORDERS THAT:**

1. The Motion to Strike Portions of OPC Surrebuttal Testimony filed by Missouri Industrial Energy Consumers on April 10, 2020, is denied.

2. The Objections to Offers of Evidence filed by The Empire District Electric Company on May 6, 2020, are denied.

3. The tariff sheets submitted on August 14, 2019, by The Empire District Electric Company, assigned Tariff No. YE-2020-0029 are rejected.

4. The Empire District Electric Company is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order.

5. The Empire District Electric Company shall file any information required by Section 393.275.1, RSMo, and Commission Rule 20 CSR 4240-10.060 no later than August 3, 2020.

6. The Empire District Electric Company shall record as a regulatory asset/liability the costs and revenues identified in the body of this order as of January 1, 2020, related to the closure of the Asbury Power Plant. The regulatory

[696] Section 386.490.3, RSMo.

asset/liability should quantify separately dollars related to the categories of costs and revenues.

7. The Empire District Electric Company shall comply with all directives, conditions and reporting requirements as more fully described in the body of this order.

8. This Report and Order shall become effective on July 11, 2020.

**BY THE COMMISSION**

Morris L. Woodruff
Secretary

Silvey, Chm., Kenney, Rupp, Coleman, and
Holsman CC., concur.

Clark, Senior Regulatory Law Judge

| | |
|---|---|
| **Missouri American Water Co.** | **Missouri-American Water Company** |
| **WR-2020-0344** | **OPC Rate Case Expense Adjustment** |
| **Amanda Conner** | **Prepared by: Amanda Conner** |
| **Rate Case Expense Estimated** | **Schedule: CAS-13 Support** |

**MAWC**

**Twelve Months Ending December 31, 2019**

**Estimated Regulatory Commission Expense**

| Description<br>(a) | Amount<br>(b) | Amount<br>(c) | 50/50 Sharing |
|---|---|---|---|
| Estimate of current rate case expense | $1,705,935 | | |
| Less: WR-2015-0301 Unamortized | $1,060 | | |
| OPC Adjustment to Estimated Rate Case Expense Amount | $1,704,875 | | $852,438 |
| Annual Normalized (3 years) | | $568,292 | $284,146 |
| Normalized level of expense for depreciation study | | $14,700 | $14,700 |
| Adjustment to Test Year - Acct. 928 | | $553,592 | $269,446 |

**Note 1:**

| | |
|---|---|
| Gannett Fleming contract estimate for the depreciation study | $73,500 |
| Amortization period (years) | 5 |
| Annual amortization | $14,700.00 |

**MAWC**

**welve Months Ending December 31, 201**

**Regulatory Commission Expense**

| Description (a) | Amount (b) | Amount (c) |
|---|---|---|
| Estimate of current rate case expense | $618,167 | |
| Annual Amortization (3 years) | | $206,056 |
| Normalized level of expense for depreciation study | | $14,503 |
| Proforma NARUC Assessment | | $9,156 |
| Other Regulatory Commission Expenses | | $56,706 |
| Proforma MPSC Assessment - 7/1/2016 - 6/30/2017 | | $1,737,018 |
| Total Proforma Regulatory Commission Expense | | $753,862 |
| Less Test Year Regulatory Commission Expense | | -$776,799 |
| | | |
| Adjustment to Test Year - Acct. 928 | | -$22,937 |

**Note 1:**

| | | |
|---|---|---|
| Gannett Fleming contract estimate for the depreciation study | $72,513 | |
| Amortization period (years) | 5 | |
| Annual amortization | $14,502.56 | |

**MAWC**

**Twelve Months Ending December 31, 2019**

**Actual Regulatory Commission Expense**

| Description | Amount | Amount | 50/50 Sharing |
|---|---|---|---|
| (a) | (b) | (c) | |
| Current rate case expense | $452,363 | | |
| | | | $226,182 |
| Annual Normalized (3 years) | | $150,788 | $75,394 |
| Normalized level of expense for depreciation study | | $14,700 | $14,700 |
| Adjustment to Test Year - Acct. 928 | | $136,088 | $60,694 |

**<u>Note 1:</u>**

| | |
|---|---|
| Gannett Fleming contract estimate for the depreciation study | $73,500 |
| Amortization period (years) | 5 |
| Annual amortization | $14,700 |

**OPC Management Expense Adjustment**
**Prepared by: Amanda Conner**

| Officers | MO Charged Amount | MO Disallowed Amount | Disallowance % |
|---|---|---|---|
| MAWC | $63,207 | $6,925 | 10.96% |
| AWC | $120,991 | $47,994 | 39.67% |
| **Total Officer** | **$184,198** | **$54,919** | **29.82%** |

| MAWC Managers | MO Charged Amount | Disallowance % | MO Disallowed Amount |
|---|---|---|---|
| | | 10.96% | $0.00 |

| | |
|---|---|
| **Total MAWC Managers** | **255** |