ATTACHMENT 1

REPORT AND ORDER

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of	)	
Kansas City Power & Light Company's	)	File No. ER-2012-0174
Request for Authority to Implement	)	Tracking No. YE-2012-0404
a General Rate Increase for Electric Service	)	

and

In the Matter of	)	
KCP&L Greater Missouri Operations Company's	)	File No. ER-2012-0175
Request for Authority to Implement a	)	Tracking No. YE-2012-0405
General Rate Increase for Electric Service	)	

REPORT AND ORDER

Issue Date: January 9, 2013

Effective Date: January 9, 2013

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 9th day of January, 2013.

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2012-0174 Tracking No. YE-2012-0404

and

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2012-0175 Tracking No. YE-2012-0405

REPORT AND ORDER

Issue Date: January 9, 2013 Effective Date: January 9, 2013

The Missouri Public Service Commission is rejecting the pending tariff sheets and ordering Kansas City Power & Light Company ("KCPL") and KCP&L Greater Missouri Operations Company ("GMO") (together, "Applicants") to file new tariff sheets in compliance with this order.

The Commission is authorizing return on equity as follows:

Applicant	*%*
KCPL	9.70
GMO	9.70

The Commission estimates that Applicants are authorized to increase the revenue they collect from Missouri customers by approximately the following amounts. [1]

[1] This number is only an estimate of the overall impact of the decisions described in this report and order and does not constitute a ruling.

Area	*Amount*
KCPL	
All	$64 million
GMO	
MPS area	$28 million
L&P area	$21 million

That estimate is based on the data contained in the updated reconciliations filed by the Commission's staff ("Staff") on January 8, 2013.

This report and order also addresses the settlement provisions incorporated into the Commission's orders. As to those matters as to which some parties agree and no parties oppose, but that are outside the Commission's subject matter jurisdiction to order, this report and order constitutes a consent order.

The Commission does not specifically discuss matters that are not dispositive. The Commission makes each ruling on consideration of each party's allegations and arguments, and has considered the substantial and competent evidence on the whole record. Where the evidence conflicts, the Commission must determine which is most credible and may do so implicitly.[2] The Commission's findings reflect its determinations of credibility and no law requires the Commission to make any statement as to what portions of the record the Commission accepted or rejected.[3]

On those grounds, the Commission independently makes its findings of fact, reports its conclusions of law,[4] and orders relief as follows.

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[2] *Stone v. Missouri Dept. of Health & Senior Services*, 350 S.W.3d 14, 26 (Mo. banc 2011).

[3] *Stith v. Lakin*, 129 S.W.3d 912, 919 (Mo. App., S.D. 2004).

[4] Section 386.420.2, RSMo 2000.

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I. Jurisdiction

The statutes give the Commission jurisdiction to determine Applicants' terms, and amounts charged, for electrical service.

Findings of Fact

1. Each applicant is a subsidiary of Great Plains Energy, Incorporated ("GPE"). GPE is a publicly traded corporation. GPE wholly owns both Applicants, neither of which is a publicly traded corporation. KCPL is a Missouri corporation. GMO is a Delaware corporation authorized to do business in Missouri. GMO is staffed with KCPL and GPE employees.

2. Applicants sell electricity at wholesale and retail. Applicant's service territories are in the central and northern parts of the western side of Missouri. GMO's service territory consists of two districts, one called MPS, and the other called L&P.

3. Applicants' customers consist of approximately the following.

KCPL	*Classification*	*GMO*
451,000	Residential	274,000
58,000	Commercial	38,000
2,100	Industrial, municipal, and other electric utilities	500
511,000	*Total*	312,000

Applicants each have their own generating capacity, but also buy power to serve their respective customers, GMO more than KCPL.

Discussion, Conclusions of Law, and Ruling

The Commission's jurisdiction generally includes every public utility corporation,[5] which includes electrical companies.[6] Electrical companies include the Applicants because

[5] Section 386.250(5), RSMo 2000.

[6] Section 386.020(15) and (43), RSMo Supp. 2012; and Sections 393.140(1).

Applicants provide electrical service to Missouri customers.[7] Regulating the Applicants' service and rates is specifically within the Commission's jurisdiction through the use of tariffs.[8] The filing of tariffs began this action. Therefore, the Commission concludes that it has jurisdiction to rule on the tariffs and determine Applicants' terms of and charges for service.

II. Procedural Background

On February 27, 2012, KCPL and GMO filed the pending tariffs seeking revenue increases approximately as follows:

Area	*Amount*	*Percentage*	*Per Day for a Typical Residential Customer*
KCPL			
All	$105.7 million	15.10%	$0.48
GMO			
MPS area	$58.3 million	10.90%	$0.27
L&P area	$25.2 million	14.60%	$0.36
GMO total	$83.5 million	11.76%	

The tariffs bear an effective date of March 28, 2012. By order dated February 28, 2012, the Commission suspended the tariff until January 26, 2013, the maximum time allowed by statute.[9]

The suspension of the tariffs initiated a contested case.[10] In the same order, the Commission set a deadline for filing applications to intervene. Movants for intervention cited varying interests in this action, including status as a supplier, industrial customer, advocacy group, seller of a competing commodity. The Commission granted applications to intervene as set forth in Appendix A, paragraph iii. Some of the intervenors are unincorporated

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[7] Section 386.020(20), RSMo Supp. 2012.

[8] Sections 393.140(11), 393.150, and 393.290, RSMo 2000.

[9] Section 393.150, RSMo 2000.

[10] Section 393.150.1, RSMo 2000; and Section 536.010(4), RSMO Supp. 2012.

associations of legal entities. On October 16, 2012, the Natural Resources Defense Council withdrew.

Intervenor Missouri Electrical Users Association-KC ("MEUA-KC"), an association of industrial customers, charges that the Commission's notice to the public was inadequate because it did not specifically refer to one of the proposals raised by another intervenor. In the order dated February 28, 2012, the Commission directed that notice of this action be provided to the county commission of each county within applicants' service area, and made notice available to the members of the General Assembly representing applicants' service area, and to the news media serving applicants' service area.[11] Further, the Commission ordered individual notice of local public hearings in this action to every customer of Applicants.[12] MEUA-KC cites no authority showing that the Commission's notice was insufficient.

By order dated April 19, 2012, the Commission established the periods relevant to the tariffs:

a. Test year to determine how much the Applicants need to provide safe and adequate service at just and reasonable rates: 12 months ending September 31, 2011;
b. Update for known and measurable changes to amounts drawn from the test year: through March 31, 2012; and
c. True-up for other significant items relevant to rates: through August 31, 2012.

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[11] *Order Suspending Tariff, Setting Pre-Hearing Conference, and Directing Filings; and Notice of Contested Case and Hearings*, issued Feb. 28, 2012, page 3.

[12] *Order Setting Local Public Hearings and Prescribing Notices*, issued June 5, 2012.

The Commission also consolidated File No. ER-2012-0174 with File No. EU-2012-0130,[13] in which KCPL sought an order authorizing deferred recording of certain amounts ("accounting authority order").

The Commission convened local public hearings in Applicants' service territories as follows.[14]

September 6	Nevada
	Sedalia
September 12	St. Joseph
	Riverside
September 13	Kansas City
	Lee's Summit

Staff filed a list of issues on October 11, 2012, and the parties filed position statements, the last on October 15, 2012.[15]

On December 21, 2012, GMO filed an application, with a request for expedited treatment, for a waiver or variance from the Commission's regulation on the costs of complying with renewable energy standards.[16] GMO also filed the same document in File No. ER-2013-0341. In the interest of administrative efficiency, and to avoid duplication of effort and potential inconsistencies, the Commission has addressed the matter under File No. ER-2013-0341.

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[13] *Order Granting Motion to Consolidate*, issued April 3, 2012.

[14] All cities in are Missouri and all dates are in 2012.

[15] An issues list and position statements function like pleadings. The issues list is a document that Staff assembles in coordination with the other parties, setting forth each matter on which any party seeks the Commission's ruling. A position statement sets forth the ruling that a party wants on an issue. Most parties take a position on less than all issues. For example, the interests of most intervenors are limited to their commercial or public policy purposes. An issues list and position statements appear late in a general rate action because not until then do the parties know which, of the countless items in the tariffs for a utility the size of Applicants, are at issue.

[16] *Application for Waiver or Variance of 4 CSR 240-20.100(6)(A) for St. Joseph Landfill Gas Facility and Motion for Expedited Treatment*, filed on December 21, 2012.

On December 24, 2012, Staff and KCPL filed notice of a new issue: [17] which demand-side programs a customer may opt out of under the Missouri Energy Efficiency Investment Act ("MEEIA").[18] Staff recommends that the Commission not address the new issue because it is too late to develop evidence and arguments. Staff is correct and the Commission will not address that matter in these actions.

On December 17, 2012, Midwest Energy Consumers Group ("MECG"), an association of large-scale purchasers, filed a motion to update its reply brief with additional authorities.[19] Applicants filed a response to that motion with additional authorities of their own on December 20, 2012.[20] Applicants filed further additional authorities on December 26, 2012.[21] The Commission will grant the motions and consider the additional authorities.

Three motions to strike remain pending. The Office of the Public Counsel ("OPC") raised the latest motion to strike in its post hearing brief. The Commission denies that motion as an untimely objection to testimony. MECG filed the first motion to strike[22] and the second motion to strike,[23] Staff joining in the latter. The first and second motions to strike addressed KCPL's proposed tariffs and supporting testimony for an interim energy charge ("IEC"). The Commission will deny the first and second motions to strike as moot because the IEC claim is among the issues that the parties have settled.

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[17] *Joint Notice of Dispute Between Staff and [KCPL] Regarding Customer Opt Out of Demand-Side Management Programs and Associated Programs' Costs*, filed by Staff and KCPL on December 24, 2012.

[18] Section 393.1075, RSMo Supp. 2012.

[19] *Motion to Update Reply Brief*, filed on December 17, 2012.

[20] *Response to MECG Motion to Update Reply Brief and Motion to Provide Supplemental Authorities*, filed on December 20, 2012.

[21] *Additional Orders in Support of Motion to Provide Supplemental Authorities*, filed on December 26, 2012.

[22] *Motion to Strike Pre-Filed Testimony and Reject Tariffs and Motion for Expedited Treatment,* filed on May 25.

[23] On July 6, 2012.

III. Settlements

A contested case allows for waiver of procedural formalities[24] and a decision without a hearing,[25] including by settlement.[26] The parties filed stipulations and agreements as follows.

<table>
<tr><th colspan="4">ER-2012-0174 and ER-2012-0175</th></tr>
<tr><td colspan="3">Partial Nonunanimous Stipulation and Agreement Respecting Kansas City Water Services Department and Airport Issues</td><td>October 19[27]</td></tr>
<tr><td colspan="3">Non-Unanimous Stipulation and Agreement as to Certain Issues</td><td>October 19</td></tr>
<tr><td colspan="3">Non-Unanimous Stipulation and Agreement Regarding Low-Income Weatherization and Withdrawal of Objection and Request for Hearing</td><td>October 26</td></tr>
<tr><td colspan="3">Non-Unanimous Stipulation and Agreement Regarding Praxair, Inc., Ag Processing Inc a Cooperative and the Midwest Energy Users' Association's Objection and Withdrawal of Objection and Request for Hearing</td><td>October 29</td></tr>
<tr><th colspan="2">ER-2012-0174</th><th colspan="2">ER-2012-0175</th></tr>
<tr><td>Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design</td><td>October 29</td><td>Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design</td><td>October 29</td></tr>
<tr><td>Second Non-Unanimous Stipulation and Agreement as to Certain Issues</td><td>November 8</td><td>Second Non-Unanimous Stipulation and Agreement as to Certain Issues</td><td>November 8</td></tr>
</table>

Also, in File No. ER-2012-0175, Staff filed its Exhibit No. 392,[28] which is the stipulation and agreement in File No. EO-2012-0009. That action addressed issues under the Missouri Energy Efficiency Investment Act ("MEEIA") and the settlement resolves all MEEIA issues. Of those stipulations and agreements, only the *Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design* in File No. ER-2012-0174, remains

[24] Sections 536.060(3) and 536.063(3), RSMo 2000.

[25] Sections 536.060, RSMo 2000.

[26] *Id*. and 4 CSR 240-2.115.

[27] All dates in this chart are in 2012.

[28] *Nonunanimous Stipulation and Agreement Resolving [GMO]'s MEEIA Filing*, filed on October 29, 2012.

opposed and so constitutes the signatories' position statement on an issue to be tried.[29] All other stipulations and agreements ("settlements") are unopposed, so the Commission will treat the settlements as unanimous. [30]

The settlements address the accounting authority order application that was the subject of File No. EU-2012-0130, consolidated into ER-2012-0174, and other claims and defenses in File Nos. ER-2012-0174 and ER-2012-0175. On the matters disposed of by settlement, no party seeks an evidentiary hearing, so no hearing is required,[31] and the Commission need not separately state its findings of fact.[32] Nevertheless, applicants have the burden of proving that increased rates are just and reasonable.[33] Except as otherwise provided by statute, the preponderance of the evidence,[34]and reasonable inferences from the evidence, [35] guide each determination.

The Commission's review of the record shows that substantial and competent evidence weighs in favor of the settlements' provisions as follows.

A. Standard for Service

The standard for service is that Applicants must provide "service instrumentalities and facilities as shall be safe and adequate [.[36]]" Upon review of the record and the settlement, the Commission independently finds and concludes that the settlement's

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[29] 4 CSR 240-2.115(2)(D).

[30] 4 CSR 240-2.115(2)(C).

[31] *State ex rel. Rex Deffenderfer Ent., Inc. v. Public Serv. Comm'n,* 776 S.W.2d 494, 496 (Mo. App., W.D. 1989).

[32] Section 536.090, RSMo 2000.

[33] Section 393.150.2, RSMo 2000.

[34] *State Board of Nursing v. Berry*, 32 S.W.3d 638, 641 (Mo. App., W.D. 2000).

[35] *Farnham v. Boone*, 431 S.W.2d 154 (Mo. 1968).

[36] Section 393.130.1, RSMO Supp. 2012.

proposed terms support safe and adequate service. Without further discussion, the Commission incorporates such terms, as if fully set forth, into this report and order.

B. Standard for Rates

The standard for rates is "just and reasonable,"[37] a standard founded on constitutional provisions, as the United States Supreme Court has explained.[38] But the Commission must also consider the customers.[39] Balancing the interests of investor and consumer is not reducible to a single formula,[40] and making pragmatic adjustments is part of the Commission's duty.[41] Thus, the law requires a just and reasonable end, but does not specify a means.[42] The Commission is charged with approving rate schedules that are as "just and reasonable" to consumers as they are to the utility.[43]

Determining whether an increase is necessary requires comparing the companies' current net income to the companies' revenue requirement. Revenue requirement is the amount of money necessary for providing safe and effective service at a profit. Those needs are tangible and intangible.[44] The Commission determines the revenue requirement from a conventional analysis of the resources devoted to service.

To provide service, a utility devotes its resources, which accounting conventions classify as either investment or expense as follows.

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[37] *Id*. and Section 393.150.2, RSMo 2000.

[38] *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of the State of West Virginia*, 262 U.S. 679, 690 (1923).

[39] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[40] *Id.* at 586 (1942).

[41] *Bluefield*, 262 U.S at 692; *State ex rel. Associated Natural Gas Co. v. Public. Serv. Comm'n*, 706 S.W.2d 870, 873 (Mo. App., W.D. 1985) (citing *Hope Natural Gas Co.*, 320 U.S. at 602-03).

[42] *Id*.

[43] *Valley Sewage Co. v. Public Service Commission*, 515 S.W.2d 845, 851 (Mo. App., K.C. D. 1974).

[44] *Hope Natural Gas Co.*, 320 U.S. at 603 (1944).

- Investment is the capital basis devoted to public utility service ("rate base") on which the utility seeks profit ("return" on investment).
    - Return is therefore a percentage ("rate of return") of rate base.
    - Rate base equals capital assets ("gross plant"), minus historic deterioration of such assets ("accumulated depreciation"), plus other items.
- Expenses include operating costs, replacement of capital items as they depreciate ("current depreciation"), and taxes on the return.

Those components relate to each other in the following formula:

- Revenue Requirement = Expenses + (Return x Rate Base)
- Rate Base = Gross Plant – Accumulated Depreciation + Other Items
- Expenses = Operating Costs + Current Depreciation + Taxes

The rate of return depends on the cost of each component in the utility's capital structure.

But determining the revenue requirement is not the entire analysis. The utility collects its revenue from its customers, who are not all the same, and so need not—and sometimes should not—receive the same treatment. The treatment afforded among the various classes of customers is rate design. Rate design should reflect the costs attributable to serving each class of customer respectively.

Accordingly, just and reasonable rates may account for such differences among customers.

C. Conclusion as to Matters Settled

Under those standards of law and policy, the Commission has compared the evidence on the whole record with the settlements. The Commission independently finds and concludes that the terms proposed in the settlement support safe and adequate service at just and reasonable rates. Therefore, the Commission will incorporate the settlements' provisions into this report and order, either as the Commission's rulings or, for those matters to which the parties agreed but the Commission has no authority to order, as the Commission's consent order.[45]

IV. Matters not Addressed in Settlements

The *Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design* in File No. ER-2012-0174 remains subject to opposition from OPC, AARP, and Consumers Council of Missouri, Inc. and so constitutes the position statement of the signatories.[46]

The Commission consolidated the actions in File Nos. ER-2012-0174 and ER-2012-0175 for hearing on the remaining disputes regarding the test year, updates, and related matters.[47] The Commission set the evidentiary hearing for October 17, 19, 22, 23, 24, 25, 26, 29, and 30, 2012. The parties stipulated to the admission of certain exhibits without objection and all such exhibits are admitted into the record. The parties filed initial briefs and reply briefs as set forth in Appendix B.

Bearing in mind the standards of law and policy set forth above, the Commission makes conclusions of law on the matters not disposed of in the settlements, with separately stated findings of fact on those remaining in dispute, as follows.

[45] Section 536.060, RSMo 2000.

[46] 4 CSR 240-2.115(2)(D).

[47] Knowing that the GPE subsidiaries would be the subject of overlapping evidence, the Commission made one record on both actions. That is why all exhibits appear under each file number in the Commission's electronic filing and information service (also called "EFIS"). Staff states that the actions "were consolidated for hearing but not for evidentiary purposes." *Staff's Reply Brief*, page 24. Because the hearing was an evidentiary hearing, Staff's statement is not well-taken.

A. KCPL and GMO

The following matters are common to both KCPL and GMO.

i. Policy Matters

AARP and Consumers Council of Missouri, Inc. ("CCoMo")—entities that advocate for residential customers—Staff, and OPC ask the Commission to put their dispute in perspective as follows.

<u>Findings of Fact</u>

1. Missouri's economy suffered more and is recovering more slowly than the rest of the nation's economy, expressed as gross domestic product, with 100 as the start of the downturn, as follows.

GDP	*Nation*	*State*
Lowest point	95.3	91.9
June 2012	101.2	94.4

Adjusted for inflation ("real GDP"), in 2011, the nation grew by 1.5% and Missouri grew by 0.04%

2. In 2010, the unemployment rate in the KCPL service area reached 9.8%. In 2011, all the counties that GMO serves had higher unemployment rates than in pre-recession 2007.

3. Between 2007 and 2011, the Consumer Price Index ("CPI") increased 11.58%. During that same time period, Applicants' customers have experienced the following increases in electric rates and weekly wages (expressed as percentages).

	Average Weekly Wages	Electric Rates
KCPL		
	11.45	43.80
GMO		
MPS	11.80	32.13
L&P	14.72	46.14

Discussion

The parties offering these matters do so as a factor affecting other matters in these actions, but seek no conclusions of law or ruling on them, so the Commission will make none.

ii. Return on Equity

The Commission is setting Applicants' return on common equity, also called return on equity, ("RoE") at 9.7%. Because RoE is so important in determining Applicants' rates, the Commission sets forth it determination on RoE first. That primacy in this report and order does not reflect an absence of other considerations, like capital structure, that influence RoE. Many are the issues affecting an appropriate RoE:

> Determining a rate of return on equity, however, is imprecise and involves balancing a utility's need to compensate investors against its need to keep prices low for consumers. [[48]]

The Commission's determination stands on evidence for which the foundation is unchallenged, and objections therefore waived, including the qualifications of any witness to offer an opinion as an expert.[49] As to each expert's testimony, the

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[48] *State ex rel. Pub. Counsel v. Pub. Serv. Comm'n*, 274 S.W.3d 569, 573-74 (Mo. App., W.D. 2009) (citations omitted).

[49] *Proffer v. Fed. Mogul Corp.*, 341 S.W.3d 184, 187 (Mo. App., S.D. 2011).

Commission may believe all, part, or none.[50] The most convincing evidence and argument is reflected in the Commission's findings of fact, as follows.

Findings of Fact

1. Return on equity ("RoE") influences the amount that a stock issuer pays to an investor, so it is a major factor in how much an investor is willing to pay for the stock. Applicants do not issue their own equity and debt. GPE issues debt and equity in Applicants' names.

2. To simulate an RoE for Applicants requires economic modeling. An accurate model requires accurate data, which means recent measures of comparable companies' earnings potentials and risks.

3. The three most commonly used economic models for simulating RoE are Risk Premium, Capital Asset Pricing Model ("CAPM") and Discounted Cash Flow ("DCF").

4. Risk Premium considers that debt is less risky than equity, so stock issuers must offer a premium to attract investors over bonds. Generally, the risk premium is the difference between cost of debt and return on equity. But return on equity is less subject to market forces for a regulated utility as it is for other businesses.

5. CAPM focuses on the degree of risk that distinguishes one investment from another. CAPM multiplies degree of risk (from standard references) times the risk premium (calculated as the difference between stock and a risk-free investment like a United States Treasury bond) and adds the risk-free rate to determine RoE.

6. DCF models posit that a stock's price equals the cumulative present value of the dividends per share that the stock will pay out for the indefinite future, discounted for a

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[50] *State ex rel. Office of Pub. Counsel v. Pub. Serv. Comm'n*, 367 S.W.3d 91, 103 (Mo. App., S.D. 2012).

present value. The discount rate is the investors' cost of equity for that stock, which is the competitive market return that investors find acceptable to hold or purchase that stock. It can be calculated as the stock's current dividend yield (as directly and precisely observed) plus the long term dividend growth rate (which must be estimated). Normally, this growth rate is assumed for simplicity to be constant, but in some applications it is assumed to change over time (e.g., the two-stage DCF).

7. The DCF formula focuses on current stock prices and dividends, consequent current dividend yields, and predicted growth rates as follows:

$$RoE = \frac{\text{current dividend}}{\text{stock price}} \times \frac{(1+\text{long-term dividend growth rate})}{2} + \text{long term dividend growth rate}$$

For those factors, current conditions are as follows.

Factor	*Conditions*
current stock dividends and prices	prices higher than dividends
predicted growth rates	Low
consequent current dividend yields	Lower

8. The best DCF analysis includes long-run investor expectations calculated by "sustainable" or earnings retention growth rates. Alternatives include published analyst earnings projections and historical trends. But projections may be overstated and are not necessarily reliable; and the most recent historical trend data is less useful than in the past due to recent economic disruptions.

9. From 2001 through 2012, capital costs have generally declined. Early in that period, utility bond yields averaged about 8% and 10-year Treasury yields about 5%. By 2011, those bond and Treasury yields had declined to 5.1% and 2.8%, respectively. In 2012, yields declined even further, to near or below the lowest levels in decades.

10. The reasons are several. The U.S. Treasury and the Federal Reserve Board bought U.S. government debt, which deflates interest rates. Other factors pushing interest rates down include low inflation rates and slow economic growth. None of those phenomena will end any time soon. That trend manifests in low inflation rates, and low ten-year Treasury yields, 3-month Treasury bill yields, and Moody's Single A yields on long-term utility bonds.

11. These disruptions also make Risk Premium and CAPM useful only as a check on the results from DCF analysis. The results from DCF analysis decrease when investor expectations decrease, which happens when interest rates decrease. Therefore, as a result of current economic conditions, RoE awards have trended lower, as shown by the national averages of other state commissions' awards:

Period	*Average*
2011	10.22
2012 first quarter	10.84
2012 second quarter	9.92
2012 third quarter	9.78
2012 first nine months	9.97

12. For future economic growth under DCF analysis, the best measure is gross domestic product ("GDP") plus inflation ("nominal GDP"). The best projections of nominal GDPs are:

Year	*Percent*
2012	3.9%
2013	4.1%
2014-15	5.1%
2018-23	4.7%

13. Currently, and for the foreseeable future, utility equity investors are accepting yields considerably lower than they have in the past. Nevertheless, returns on electric utility stocks are relatively stable and Applicant's business risk has not

increased since the Commission set Applicants’ RoE at 10.0% on April 27, 2011. GPE’s relatively strong capital structure supports a lower RoE for Applicants.

14. An RoE of 9.7 is enough for both KCPL and GMO to continue operating and to attract investment.

Conclusions of Law

Applicants have not carried their burden of proving that their RoE should be in the range they propose and, of all parties’ evidence and argument, the single most persuasive is that of the federal executive agencies (“FEAs”), entities within the United States’ government that are customers of Applicants.

The parties sponsored witnesses testifying to RoE ranges and recommendations as follows.

Sponsor	*Range*	*Recommendation*
Staff	8.00 to 9.00	9.00
OPC	9.10 to 9.50	9.40
FEAs	8.80 to 9.80	9.50
Applicants	9.80 to 10.30	10.30

Of the ranges supported by expert testimony, the authorized RoE is:

- within the FEAs’,
- between OPC’s and Applicants’, and
- outside Staff’s,

as follows.

<table>
<tr><td></td><td colspan="5">FEAs
8.80 to 9.80</td><td></td></tr>
<tr><td>Staff
8.00 to 9.00</td><td></td><td>OPC
9.10 to 9.50</td><td></td><td>Authorized
9.70</td><td></td><td>Applicants
9.80 to 10.30</td></tr>
</table>

The Commission will discuss the parties’ cases in the following order:

- The FEAs first because their case is the most persuasive,

- Applicants and OPC next because their experts' analyses bracket the authorized RoE, and
- Staff last because its expert's range is the outlier.

FEAs. The FEAs suggest a range of 8.8% to 9.8%, which includes the authorized RoE of 9.7%. The Commission finds their analysis the most persuasive for several reasons. The FEAs' expert used the Applicants' first proxy group[51] and so begins his analysis on the same footing. For growth projections, the FEAs' expert employed multiple sources of published projections, but did not rely on these alone, resulting in a more thoroughly researched result. The FEAs' expert also generously considered potential future earnings growth contribution from issuance of new common stock at prices above book value.

Applicants. Applicants suggest a range of 9.80% to 10.30%. In support of that range, Applicants offer several standard analyses, and one non-standard analysis, but all the results are exaggerated because of the values that Applicants use in the formulas.

Applicants' proxy group changed between the filing of their direct testimony and rebuttal testimony. The second group omitted three of the companies with the lowest RoE, while retaining the three companies with the highest RoE, and adding companies with higher-than-average RoEs. Inevitably, that raises the resulting RoE.

Also troubling is the DCF Terminal Value model that Applicants offer. DCF analyses look at long-term events but DCF Terminal Value looks at just four years. It is a new approach to DCF and is not in general use. Also, the proffered analysis is flawed. The DCF Terminal Value analysis stands on the premise that current low interest rates make debt less attractive to investors, who therefore invest in stocks at prices higher than usual. The analysis assumes that investors will pay a price-to-earnings ("P:E") ratio of 16:1 through 2016. But the analysis also claims that interest rates will soon rise, which will send investors back to debt instruments and away from stocks, undercutting the 16:1 P:E ratio on which the analysis relies.

Further, all Applicants' DCF analysis share certain flaws. They use a 5.7% GDP projected from 1971-1980 data, which is not helpful compared to the 30 most recent lower growth years, and does not reflect investor expectations. Nor does that rate account for events likely to shape GDP in the future. Given the economic conditions currently prevailing, it is not credible that investors today use a 5.7% GDP to assess their expectations for low-risk investments.

Moreover, Applicants' attempt to adjust for the economic intervention of the U.S. Treasury and the Federal Reserve Board that is lowering interest rates undercuts the DCF model itself. To an investor, a decrease in return figures into the price investors will pay for an investment only because it is a decrease, and the reason for the decrease is irrelevant whatever the cause. The markets are not wrong— RoE cannot increase when risk has not increased and capital costs have decreased.

Thus, Applicants' DCF analyses (other than Terminal Value) are sound but the variables employed exaggerate the results. Therefore, the Commission rejects Applicant's suggested range of RoEs. Nevertheless, the Commission notes that

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[51] Applicants' RoE witness changed his proxy group over the course of litigation, skewing his results, as

Applicants' second proxy group has a median RoE of 9.8 percent, which is just above the authorized RoE of 9.7%.

OPC. Just below the authorized RoE is the analysis of OPC's witness. OPC's witness offers a range of 9.1% to 9.5%, based on investor expectations of both short-term growth and long-term sustainable growth, therefore employing multi-stage DCF analysis, which thus constitutes a thorough consideration. The Commission finds the analyses slightly too cautious, resulting in results too modest, so the Commission rejects it. Nevertheless, the Commission notes that, accounting more fully for the inverse relationship between risk premiums and interest rates OPC's expert analysis results in a range that includes the authorized RoE of 9.7%.

Staff. Staff suggested one range at hearing and another in briefing, but neither is entirely persuasive for the following reasons.

At hearing, Staff offered a range of 8.00% to 9.00%. In support of that range, Staff offers data from the period between 1968 and 1999. After that period, Staff alleges, industry disruptions make data unreliable, and an earlier period analogous to recent years more useful. Those arguments do not persuade the Commission that data from a remote period starting 44 years ago is more reliable for determining recent RoE than more recent data. Therefore, the Commission rejects the 8.00% to 9.00% range.

In briefing, Staff argues for an expanded range of 8.00% to 9.78%. The new upper end comes from a variety of sources including the downward trend in national averages of other state commissions' RoE awards as the Commission has found:

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described more fully below.

Period	*Average*
2011	10.22
2012 first quarter	10.84
2012 second quarter	9.92
2012 third quarter	9.78

Those numbers are relevant, not because any other RoE ruling on different facts and different law helps calculate Applicants' RoE, but because Applicants must be able to attract capital. An RoE set too low will, as discussed above, unlawfully handicap Applicants when they compete for capital in the national marketplace.

Staff cites the 2012 third quarter amount—9.78%—for the high end of its expanded range. But the lower end of the expanded range comes from the discredited data discussed in the preceding paragraph. For that reason, the Commission does not entirely embrace the expanded range for RoE.

Nevertheless, the Commission notes that the authorized RoE is well within the upper end of Staff's expanded range.

Zone of Reasonableness. The national marketplace is also among the factors that help the Commission establish a zone of reasonableness for Applicants' RoE.[52] Based on the downward trend in national averages of other state commissions' RoE awards, the continuing downward pressure on interest rates nationally, the slower-than average recovery in Missouri, and the copious testimony of the many experts, the Commission has found a reasonable opportunity for Applicants to earn a reasonable return on their investment exists at 9.7%.

The Commission's Ruling. In proposing an RoE for Applicants, all experts agree that setting an RoE is not merely a matter of arithmetic. RoE is a multi-

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[52] *State ex rel. Pub. Counsel v. Pub. Serv. Comm'n*, 274 S.W.3d 569, 574 (Mo. App., W.D. 2009), citing

disciplinary exercise culminating in the application of the Commission's policy expertise. The factors influencing an RoE are legion, balancing or outweighing one another in permutations too numerous for any expert to fully catalogue, and growing exponentially as experts compare each others' models.

Among those myriad factors, the testimony indicates that a lower RoE may be appropriate for a utility that has an FAC like GMO than for a utility that does not have an FAC like KCPL, all things being equal. But no witness quantifies a difference between the Applicants, which implies that all things are not equal, and that other factors outweigh the distinction of the FAC, and support the same RoE for KCPL as for GMO: 9.7%.

An RoE of 9.7% lies within the zone of reasonableness as determined by the courts of Missouri and the United States. It will also allow Applicants to compete in the market for capital that they need to maintain their financial health, without raising rates unnecessarily. Therefore, the Commission concludes that an RoE of 9.7% for each of the Applicants will best support safe and adequate service at just and reasonable rates, and the Commission will order that RoE.

ii. Capital Structure

The Commission is ordering a capital structure reflecting GPE's actual capital structure for each Applicant.

Findings of Fact

1. As of August 31, 2012, GPE's capital structure is 46.84 % debt to 53.16% equity (52.56% common and 0.60% preferred).

In re Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

2. Ordinarily, capital structure excludes short-term debt and includes long-term debt. GPE is re-financing long-term debt with short-term debt. The short-term debt excluded from GPE's capital structure is thus a temporary substitute for long-term debt. This makes the capital structure more equity-rich, which is more expensive. But GPE is consolidating the short-term debt for re-financing back into long-term debt which is likely to attract more buyers and cost less in interest.

3. GPE's capital structure also excludes other comprehensive income ("OCI"), which is ordinarily included in equity.

Discussion, Conclusions of Law, and Ruling

Applicants have carried their burden of proving that the actual capital structure of GPE as described by Applicants is more likely to support just and reasonable rates than the proffered alternatives. But the FEAs have shown that the capital structure should include Other Comprehensive Income ("OCI") in equity.

OPC and MECG argue for a hypothetical capital structure of 50% debt to 50% equity. In support, they cite the exclusion of short-term debt because it is a temporary stand-in for long-term debt, which is ordinarily included in capital structure. The argument for including the short-term debt is not without merit. But its proponents have not shown how including short term debt leads to the structure of 50% debt to 50% equity. Nor have they shown how much of the shift should come from preferred equity. Their proposal lacks evidentiary support and adopting it would be merely arbitrary.

The FEAs challenge Applicants' exclusion of OCI. Applicants argue that, while OCI is ordinarily part of equity, the relevant periods' OCI is more accurately allocated to debt because it comes from settled interest rate derivatives' unamortized net-of-tax income or loss. Applicants cite no provision of USoA supporting that adjustment, so they have not carried their burden of proof on that issue. Therefore, the Commission will order that OCI shall be part of equity.

The Commission concludes that safe and adequate service at just and reasonable rates has better support in a capital structure for each Applicant at the actual capital structure of GPE as Applicants describe it—46.84 % debt to 53.16% equity (52.56% common and 0.60% preferred)—but including OCI, so the Commission will order that capital structure.

iii. Cost of Debt

The Commission is ordering that GPE's consolidated cost of debt be assigned to Applicants at 6.425% and is not ordering the reductions in interest suggested by Staff.

Findings of Fact

1. Aquila committed to assess debt costs to Missouri ratepayers at a rate consistent with a "BBB" credit rating. Aquila lost its investment grade credit rating and had to take on higher-cost debt.

2. When GPE acquired Aquila, now known as GMO, it boosted GMO's credit rating by guaranteeing its debt. As of July 2, 2012, all the Aquila high-cost debt is gone from GMO's books. GMO now has an investment grade credit rating. But GMO does not have ratings as high as KCPL, so GMO still pays more interest than Aquila promised to pass on to ratepayers, and more interest than KCPL has to.

3. GPE's consolidated cost of debt is 6.425%.

Discussion, Conclusions of Law, and Ruling

Applicants and Staff agree that the Commission should assign GPE's consolidated cost of debt to each Applicant, and GPE's practice of issuing securities in Applicants' names supports that practice.

Staff argues that the Commission should order each Applicant's consolidated cost of debt to be 6.187% by reducing GPE's notes as follows:

GPE Note	Recommended Reduction in Basis Points	Basis Point Estimate
$250 million, 3-year, 2.75%	60 to 75	65
$350 million, 10-year, 4.85%	60 to 85	65
$287.5 million, 10-year, 5.292%	110 to 120	115

In support, Staff argues that its adjustments align GMO's cost of debt with KCPL. KCPL's rating, Staff argues, would also be GMO's but for the misdeeds of Aquila. Hence, this is one of several Aquila legacy matters.

Staff's arguments are unpersuasive. Their basis—what GMO would look like if the past were different—is speculation. By contrast, no party disputes that GMO's ratings have improved under current management. And using GPE's consolidated cost of debt is more consistent with the capital structure that the Commission has ordered, which is based on GPE's actual capital structure.

Though succeeding to assets generally means succeeding to liabilities, for Missouri citizens it also means the rescue of a distressed utility and preservation of service. Those considerations suggest that the Commission's treatment of GMO should not stray too far into punitive action. The Commission concludes that a cost of debt at 6.425% will better support safe and adequate service at just and reasonable rates.

Therefore, the Commission concludes that a cost of debt for each Applicant at 6.425%, and without Staff's proposed adjustments, will better support safe and adequate service at just and reasonable rates, so the Commission will order that cost of debt for each of the Applicants.

iv. Transmission Tracker

Applicants have not carried their burden of proving that the Commission should order deferred recording ("a tracker") for transmission costs. The issue is moot because Applicants can already determine how to record that cost by themselves, as they do with almost every cost every day, under the *Uniform System of Accounts* ("USoA").

Findings of Fact

1. Applicants pay to send and receive power ("transmission") through the territory of regional transmission organizations including the Southwest Power Pool ("SPP"). The costs for transmission include:

Name	*USoA Account*
Transmission Costs	565
Schedule 1-A Administration Charge	561 and 575
Schedule 12 Assessment Fees	928

2. SPP's regional transmission upgrade projects and increasing SPP administrative fees are increasing Applicants' transmission costs as follows.

Calendar Year	Cost ($ million)	
	KCP&L	GMO
2012	$18.4	$6.8
2014	$25	$9.2
2019	$45.2	$16.7

Those increases represent an approximately 14% increase per year. Each of those amounts represents more than five percent of the respective applicant's income, computed before those costs.

4. Transmission costs will continue to increase at an accelerating pace.

Discussion, Conclusions of Law, and Ruling

The Applicants ask the Commission to order deferred recording[53] (a "tracker") for transmission costs. But that matter is moot because the Commission can grant no practical relief.[54] No practical relief is possible because Applicants can already "track" transmission cost increases under the plain language of the only authority that any party cites for a tracker.

That authority is the *Uniform System of Accounts* ("USoA"), which is the set of federal regulations that governs utilities' recording of gains and losses ("items"). 18 CFR 201. The Commission's regulation 4 CSR 240-40.040(1) incorporates USoA's *General Instructions, Definitions*, and *Balance Sheet Accounts Assets and other Debits* ("*Accounts*") into the Commission's regulations. 4 CSR 240-40.040(1). Specifically applicable are Accounts 182 and 254, other regulatory liabilities and assets, respectively, set forth at length in Appendix C. Those provisions describe accounts for recording an item outside the year of occurrence ("deferral") for determination in a later action.

Whether a utility may defer an item is the subject of General Instruction No. 7. General Instruction No. 7 provides that the Commission's order is only necessary for an item that is less:

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[53] Deferred recording was the subject of File No. GU-2011-0392, *In the Matter of the Application of Southern Union Company for the Issuance of an Accounting Authority Order Relating to its Natural Gas Operations* [,] *Report and Order* issued on January 25, 2012. Though that order does not constitute precedent and does not control the Commission. *McKnight Place Extended Care, L.L.C. v. Missouri Health Facilities Review Comm.*, 142 S.W.3d 228, 235 (Mo. App., W.D. 2004), the Commission finds the analysis in that order both insightful and persuasive. The event at issue in File No. GU-2011-0392 was the multi-vortex Joplin tornado of 2011.

[54] *Precision Invs., L.L.C. v. Cornerstone Propane, L.P.,* 220 S.W.3d 301, 304 (Mo. banc 2007).

> . . . than approximately 5 percent of income, computed before extraordinary items. Commission approval must be obtained to treat an item of less than 5 percent, as extraordinary. [[55]]

"Extraordinary" describes matters subject to deferral, and does not apply to transmission cost increases, as discussed below. But even if transmission cost increases were extraordinary, Applicants' evidence shows that transmission costs are not less than five percent of income. Therefore, no Commission order is needed to defer the transmission costs, and Applicants can decide for themselves whether to defer the transmission costs.

Whether to defer an item is a decision that Applicants make every day because it is simply a matter of recording. Recording any item ordinarily means assigning it to the year in which it occurred ("the period"):

> [N]et income <u>shall reflect all items</u> of profit and loss <u>during the period</u> with the exception of [certain items.[56]]

And:

> <u>All other items</u> of profit and loss recognized during the year <u>shall be included</u> in the determination of net income <u>for that year</u>. [[57]]

But, if an item with far-reaching impact for Applicants and their customers falls outside the test year, omitting that item from consideration may threaten just and reasonable rates. To protect just and reasonable rates, the Commission allows deferral for:

> Extraordinary items. . . . Those <u>items related to the effects of events</u> and transactions which have occurred during the current period and which are of unusual nature and infrequent occurrence <u>shall be</u> 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

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[55] General Instruction No. 7.

[56] General Instruction No. 7 (emphasis added).

[57] General Instruction No. 7.1 (emphasis added).

> not reasonably be expected to recur in the foreseeable future [.[58]]

That language examines an event's:

- Time (during current period);
- Effect (significant);
- Rarity (unusual, infrequent, not foreseeably recurring, activities abnormal and significantly different from the ordinary and typical).

Applicants have not proved that the transmission cost increases meet that standard. The projected transmission cost increases are not "extraordinary" within the legal definition because they are not rare or current.

"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.

As to time, Applicants project increases on a yearly basis so each projection will apply to its respective "current period [.]" But no party cites any authority under which the Commission may order deferral of an item before the item occurs. And that predetermination—a ruling on facts that have not occurred—is what makes a "tracker" different from an accounting authority order under USoA's plain language. Thus, "items

[58] General Instruction No. 7 (emphasis added).

related to the effects of" future transmission cost increases are not current and, therefore, are not extraordinary.

Because Applicants have not shown that the projected transmission increases are current and will be rare, Applicants have not carried their burden of proving that the projected transmission increases are extraordinary. If the increases—once they happen—prove to be less than five percent of income, Applicants may apply for an accounting authority order under the law they cite. If the projected transmission increases prove to be more than five percent of income, they will be subject to deferral without the Commission's order.

Either way, the law provides a "regulatory mechanism to ensure that increasing SPP transmission expenses between rate cases are appropriately deferred for possible recovery in a future rate proceeding."[59] The only thing that the Commission is denying Applicants is a blessing upon the treatment of facts that have not yet occurred, an order for which Applicants cite no authority in the law. Whether the Commission can create a transmission tracker by regulation, or the General Assembly can create a tracker by legislation, or some other jurisdiction has already done either, does not change the result.

For those reasons, the Commission concludes that denying a tracker is consistent with the law and does not threaten safe and adequate service at just and reasonable rates, so the Commission will not order a transmission tracker.[60]

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[59] *Reply Post-Hearing Brief of [KCPL] and [GMO]* page 25, paragraph 69.

[60] This conclusion renders it unnecessary to determine whether USoA General Instruction 7 represents unconstitutional retro-active ratemaking, or single-issue ratemaking that is contrary to statute as some parties argue. No party cites any authority under which the Commission may declare a regulation unconstitutional or resort to the statutes with which its own regulation conflicts.

v. Winter, Space Heat, and All-Electric

The Commission is changing Applicants' respective rate designs to bring certain classes of customer closer to paying the cost of serving them ("recovery"). The Commission:

- Is not eliminating and not freezing Applicants' residential space-heat classes.
- Is shifting[61] KCPL's costs of service away from small and general service rates and toward large power service as OPC proposes.
- Is increasing KCPL's first blocks of the residential space heating rates and winter All-Electric General Services rates, and GMO's non-residential and residential rates, as Staff proposes.
- Is not implementing the increasing residential true-up revenues by the additional 1.00%, with a corresponding equal-percentage revenue neutral decrease in the true-up revenues for all other non-lighting rate classes, proposed by signatories to the *Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design* in File No. ER-2012-0174.
- Is not raising any monthly customer service charge.

The Commission bases those determinations on the credibility of the witnesses supporting the class cost of service studies ("CCoSSs") and other evidence, and the Commission's policy choices that, together, suggest relief as follows.

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[61] The parties use this term in different ways. For Staff, it means an increase in one place with no corresponding decrease in another. For Applicants and OPC, and this report and order, it means decreasing rates in one schedule and raising them correspondingly in another.

Findings of Fact

1. All of Applicant's customer classes recover their costs but some recover more than others. Recovery is among the focuses of experts in rate design because how much one class recovers determines how much other classes must recover. That creates the mechanism for one class to subsidize another, the use of which experts in rate design determine based on economic conditions, including those described in section IV.A.i of this report and order.

2. Because winter is Applicants' off-peak season, certain of Applicants' rate schedules recover less than their class's cost of service. Those schedules are, for KCPL:

- Residential general use and space heat – one meter ("RESB"),
- Residential general use and space heat – two meters separately metered, space heat rate ("RESC"),
- All-electric Small General Service ("SGS"), and
- All-electric Medium General Service ("MGS");

and for GMO:

- Residential service with space heating ("L&P MO 920 rate schedule"),
- Residential space heating / water heating – separate meter ("L&P MO 922 Frozen rate schedule"), and
- Non-residential space heating/water heating – separate meter ("L&P MO 941 Frozen rate schedule").

3. For example, KCPL's RESB generates a 5.859% return in the summer, but only 2.922% in the winter, and RESC generates 4.161% in the summer and only 2.284% in the winter.

4. Nevertheless, those rates recover their costs of service over the course of a year, do not constitute a discount or promotion, and do not constitute a subsidy of all-electric and space heat customers.

5. If residential space heat rates were eliminated or priced out of the market, Applicants would lose part of their winter load, and the profit margin it represents. To maintain their profitability, Applicants would have to seek that margin through other rates.

6. For example, a typical KCP&L customer's bill would increase 24.83%. A typical GMO's L&P customer's bill would increase 12.58%. For GMO's space heating customers, \$50.88 per year at the low-use end and \$674.88 for customers at the higher usage level of 4,000 kilowatt hours per month, or 17.53%. Those increases do not consider any increase ordered in this action.

7. To freeze a rate is to close it to new customers. Frozen rate tariff language has proven to be difficult to draft and administer for other services. Such a tariff has caused confusion among the utility, customers, and the Commission. The result was multiple customer complaints and litigation.[62]

8. On a scale in which 1.0 represents KCPL's system-average rate of return, KCPL's rate classes contribute to KCPL's rate of return as follows.

Residential	0.98
Small General Service	1.98
Medium General Service	1.28
Large General Service	1.05
Large Power Service	0.54

9. KCPL devotes \$431,849,089 of its rate base to its Large Power Service ("LP"), which generates a 3.011% return, compared to the system average return of 5.539%.

10. Rate design sometimes employs two components for billing: a periodic customer charge that does not vary with use, and a volumetric charge that varies with usage. The amount of service the customer uses determines the volumetric charge, so the volumetric charge is more within the customer's control.

Conclusions of Law

Applicants propose that any increase awarded in this report and order apply equally to all classes and rate components, after any adjustment specific to any class, and MEUA-KC concurs. Staff, OPC, and Southern Union agree, but each adds a set of adjustments to remedy the disparity in certain classes between costs and recovery. The parties' proposals include the following.

- Eliminate space heat and all-electric rates (either immediately[63] or gradually through freezing[64]),
- Shift revenue among rate schedules,[65] and
- Raise some space heating and all-electric rates.[66]

Counter-proposals and other matters arise in response. Therefore, the Commission will order that any increase awarded in this report and order apply equally to all classes and rate components, after any adjustment specific to any class, as follows.

Eliminate Space Heating and All-Electric Rates. Southern Union d/b/a Missouri Gas Energy proposes eliminating Applicants' space-heating classes, either immediately or

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[62] *Briarcliff Developments v. Kansas City Power & Light Company*, Case No. EC-2011-0383, *Report and Order* issued Mar. 7, 2012.

[63] Issues List I.6.g.i. and III.7.e.i.

[64] Issues List I.6.g.ii. and III.7.e.ii.

[65] Issues List I.6.f.i. and III.7.d.i.

[66] Issues List I.6.g.iii and I.6.d; and III.e.iii and e'.

gradually after freezing those classes. In support, Southern Union offers several arguments. The Commission rejects that proposal as follows.

Southern Union alleges that residential space-heating rates represent an unfair subsidy from other customers, because they return less than other classes. The Commission has found otherwise; there is no such subsidy. Contrary to Southern Union's allegations, Applicants have shown that elimination of space heating rates would cause a hardship on Applicant's customers. Moreover, such hardship would be even greater under Southern Union's calculations. Southern Union's alternative, gradual elimination by freezing space heating rates, causes its own set of difficulties, as the Commission has learned from experience.

Southern Union also argues that residential space-heating rates are a policy relic of an earlier time, when the Commission favored electricity over natural gas for reasons that no longer exist, especially price. Southern Union cites the recent drop in natural gas prices. The Commission is aware of that development but is also aware of the investment that customers have made in reliance on those classifications, which represents a commitment that such rates represent among Applicants, customers, and the Commission. The Commission will not abandon its part of that commitment.

Southern Union asks whether it is fair that two of Applicants' customers pay different amounts for electricity just because one is all-electric? The answer is yes, if the record supports that result. Even ignoring Southern Union's obvious incentive to make electricity less attractive than natural gas, the Commission concludes that eliminating residential space heat rates—suddenly or gradually through freezing—does not support safe and adequate electric service at just and reasonable rates.

Revenue Shift among Rate Schedules. For KCPL, the low contribution to return of Large Power ("LP") and high contribution from Small Gas Service ("SGS") and Medium Gas Service ("MGS") requires a remedy.

Based on KCPL's CCoSS, which is in part the basis of the Commission's findings, OPC proposes to increase LP as follows. It takes the difference between LP return (3.011%) and KCPL's system-average return (5.539%). The difference is 2.528% (5.539% - 3.011%). The amount of LP rate base under-contributing is therefore $10,917,144. (2.528% x $431,849,089).

Using those amounts, OPC recommends shifting half the under-contributing LP rate base ($10,917,144 x ½ = $5,458,572) to decrease SGS and MGS by a 69% / 31% split:

$5,458,572 x 69% = $3,319,366 decrease to SGS,

$5,458,572 x 31% = $2,139,206 decrease to MGS,

with the remaining $5,458,572 as an increase to LP.

The results are:

- LP increases by $5,458,572, which is 50% of KCPL's CCoSS shifts.
- MGS decreases by $2,139,206, which is 39% of the LP increase; and
- SGS decreases by $3,319,366, which is 61% of the LP increase.

The Commission concludes that the shifts that OPC proposes for KCPL best furthers the policy of moving rates toward recovery. That is because it represents a middle ground between the undesirable results of the status quo (leaving disparities in recovery unaltered) and eliminating all disparities immediately (causing rate shock). The Commission concludes that OPC's proposal will best support safe and adequate service at just and reasonable rates, so the Commission will order the shifts that OPC proposes for KCPL.

Increase Space Heating and All-Electric Rates. In this matter, the Commission must resolve two policies that, as of this date, conflict. The general consensus is that a class of customers should pay for the cost of serving them. But the Commission's finding on lingering economic hardships, as set forth in section IV.A.i of this report and order raises a reluctance to increase rates. This is especially true of residential customers, who cannot simply pass on the expense to someone else. The Commission is applying its policy-making expertise by ordering rates altered according to the proposal of Staff.

Staff proposes to gradually move recovery toward winter costs by increasing certain rates, in addition to any other revenue increase required by this report and order, as follows. For KCPL, 5% to each of the following:

- First winter block of RESB (residential general use and space heat – one meter); and
- Winter season separately metered space heat rate of RESC (residential general use and space heat – two meters).

For GMO, 6% to each of the following:

- L&P MO 920 rate schedule (residential service with space heating), the two winter energy block rates;
- L&P MO 922 Frozen rate schedule (residential space heating / water heating – separate meter), the winter energy rate; and
- MO 941 Frozen rate schedule ("non-residential space heating / water heating – separate meter").

OPC concurs as to the KCPL increases. As to all Staff's proposed increases, the Commission concludes that safe and adequate service at just and reasonable rates finds the most support in the shifts that Staff proposes for KCPL. Therefore, the Commission will order those increases as Staff recommends.

Additional 1% for KCPL Residential Rates. The signatories to the KCPL *Non-Unanimous Stipulations and Agreements Regarding Class Cost of Service / Rate Design* agree that the Commission should increase KCPL residential true-up revenues by 1% in addition to any other increase, with a corresponding equal-percentage revenue decrease in true-up revenues for all other non-lighting rate classes. OPC objects, and AARP and CCoMO join in that objection. The objectors are correct that the slow recovery from economic woes, on which the Commission heard much testimony during local public hearings, supports no more increase in residential rates than the Commission has already reluctantly ordered. Therefore, the Commission will rule in favor of OPC and against the 1% residential increase that OPC opposes.

Customer Charge.[67] OPC asks the Commission that any increase in residential rates not apply to the monthly customer charge. AARP and CCoMO concur. Because volumetric charges are more within the customer's control to consume or conserve, the volumetric rate is the more appropriate to increase. Therefore, the Commission will order that any increase in residential rates should not apply to the monthly customer charge.

Rulings. The Commission concludes that the grant and denial of rate shifts and increases as described above will best support safe and adequate service at just and reasonable rates, so the Commission will order those shifts and increases accordingly.

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[67] Issues List I.6.f.ii and III.7.d.2.

vi. PURPA

Staff seeks a determination that the Commission and Applicants need take no further actions under certain federal laws. That request has no opposition from any party.

Findings of Fact

1. To address the four Energy Independence and Security Act of 2007 ("EISA") standards, the Commission established Files No.

a. EW-2009-0290 ("IRP Docket");[68]

b. EW-2009-0291 ("Rate Design Docket");[69] and

c. EW-2009-0292 ("Smart Grid Docket").[70]

In each of those files, the Commission issued its *Order Finding Consideration / Implementation of New Federal Standards through Workshop and Rulemaking Procedures Is Required*,[71] stating at page 5:

> The Commission has satisfied the requirements for consideration of the new EISA standards, and on the basis of the quasi-legislative record created in these workshops, the Commission determines that no comparable standards have been considered that would constitute prior state action and prohibit the Commission from taking any further action in relation to the new EISA standards [.]

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[68] *In the Matter of the Consideration of Adoption of the PURPA Section 111(d)(16) Integrated Resource Planning Standard as Required by Section 532 of the Energy Independence and Security Act of 2007*.

[69] *In the Matter of the Consideration of Adoption of the PURPA Section 111(d)(17) Rate Design Modifications to Promote Energy Efficiency Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007*.

[70] *In the Matter of the Consideration of Adoption of the PURPA Section 111(d)(18), Smart Grid Investments Standard, and the PURPA Section 111(d)(19), Smart Grid Information Standard, as Required by Section 1307 of the Energy Independence and Security Act of 2007*.

[71] Issued on November 23, 2009.

2. The Commission promulgated a rulemaking in File No. EX-2010-0368,[72] as a result of which Commission regulations 4 CSR 240-20.093, 20.094, 3.163, and 3.164The rules became effective on May 30, 2011.

3. The Commission's promulgation of a rulemaking revising Chapter 22 Electric Resource Planning Rules in File No. EX-2010-0254[73] became effective on June 30, 2011.

4. The Commission opened a repository on December 29, 2010, for information concerning the Smart Grid in Missouri as File No. EW-2011-0175. In File No. EW-2011-0175, on January 13, 2011, Staff, filed the *Missouri Smart Grid Report* Among other things, the *Missouri Smart Grid Report* presents issues and concerns and identifies key issues requiring further emphasis, including Smart Grid deployment, planning, implementation, cost recovery, cyber security and data privacy, customer acceptance and involvement, and customer savings and benefits. It recommends the Commission hold a Smart Grid workshop every six months for information exchange and sharing of best practices and educational opportunities; and also recommends the Commission open a docket to address cost recovery issues.[359]

5. The Commission has also held Smart Grid conferences on June 28, 2010, and November 29, 2011, and the Smart Grid was also the recent subject of the *PSConnection*, a publication of the Commission. On July 17, 2012, the Commission issued an *Order Directing Notice and Directing Filing* in File No. EW-2013-0011 to gather information related to cyber vulnerabilities and the integrity of the electric utilities' internal cyber security practices. This workshop proceeding provides another

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[72] *In the Matter of the Consideration and Implementation of Section 393.1075, The Missouri Energy Efficiency Investment Act*.

opportunity for the Commission to explore issues and take action related to the PURPA Smart Grid Investments standard. The Commission on October 5, 2012 issued a *Notice And Order Setting On-The-Record Proceeding* scheduling an on-the-record proceeding in File No. EW-2013-0011 for November 26, 2012 regarding cyber security practices.

6. In 2009, Governor Nixon signed Senate Bill 376, the "Missouri Energy Efficiency Investment Act," with a stated policy [74] to "value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs."

7. The Commission has a workshop docket, Case No. EW-2010-0187, open to investigate how to achieve its statutory responsibilities under the Missouri Energy Efficiency Investment Act ("MEEIA"),[75] among other things, within the background of Federal Energy regulatory Commission ("FERC") policies that eliminate barriers to demand response and that direct the Midwest Independent Transmission System Operator ("MISO") and the Southwest Power Pool ("SPP") to accommodate state policy regarding retail customer demand-side activity.

8. On December 22, 2011, KCPL[76] and GMO[77] each submitted a MEEIA application.

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[73] *In the Matter of a Proposed Rulemaking Regarding Revision of the Commission's Chapter 22 Electric Utility Resource Planning Rules*.

[74] Section 393.1075.3, RSMo Supp. 2012.

[75] Section 393.1075, RSMo. Supp. 2012.

[76] File No. EO-2012-0008.

[77] File No. EO-2012-0009.

9. KCPL dismissed its action on February 17, 2012. The Commission closed that file on March 6, 2012. Nevertheless, the Commission has in place the framework necessary to make a determination on the associated PURPA principles.

10. In GMO's action, certain parties filed the *Non-Unanimous Stipulation And Agreement Resolving KCP&L Greater Missouri Operations Company's MEEIA Filing* ("GMO MEEIA settlement"), filed in File No. ER- 2012-0175 as Exhibit No. 392.[78]

11. On November 7, 2012, in File Nos. ER-2012-0174 and ER-2012-0175, the Commission issued an *Order Incorporating Unopposed Non-Unanimous Stipulations And Agreements* in which it incorporated, as if fully set forth at length, the GMO MEEIA agreement as modified by the October 26, 2012 *Non-Unanimous Stipulation And Agreement Regarding Low-Income Weatherization And Withdrawal Of Objection And Request For Hearing* and October 29, 2012 *Non-Unanimous Stipulation And Agreement Resolving KCP&L Greater Missouri Operations Company's MEEIA Filing*, among other documents.

12. On November 15, 2012, the Commission in File No. EO-2012-0009 issued an *Order Approving Non-Unanimous Stipulation and Agreement Resolving KCP&L Greater Missouri Operations Company's MEEIA Filing*.

Discussion, Conclusions of Law, and Ruling

The Commission must consider and determine whether to implement each of the four "new" Public Utility Regulatory Policies Act of 1978 ("PURPA") Section 111(d) standards for electric utilities established by Congress through the Energy Independence and

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[78] On November 19, 2012.

Security Act of 2007 ("EISA") so as to carry out the purposes of PURPA, which are to encourage:

(1) conservation of electric energy,

(2) efficiency in the use of facilities and resources by electric utilities, and

(3) equitable rates to consumers of electricity.[348]

If the Commission determines that a standard is appropriate to carry out the above-noted purposes, but declines to implement it, the Commission must state in writing its reasons. The law required the Commission to complete its consideration and determination of each standard no later than December 19, 2009. Absent such determination, the Commission is to consider whether or not it is appropriate to implement such standard to carry out the above noted purposes in the first general rate case for each individual electric utility commenced after December 19, 2010. Staff asks the Commission to consider each standard and make its determination with respect to Applicants.

PURPA Section 111(d)(16), Integrated Resource Planning Standard as required by Section 532 of EISA, requires state commission consideration of whether to implement the following:

(A) integrate energy efficiency resources into utility, State, and regional plans; and

(B) adopt policies establishing cost-effective energy efficiency as a priority resource.

While not specifically making a determination to implement PURPA Section 111(d)(16), the Commission has promulgated rulemakings to address the principles of that section.

Therefore, the Commission concludes that nothing remains for the Commission to determine in response to PURPA Section 111(d)(16) for KCPL and GMO.

PURPA Section 111(d)(17), Rate Design Modifications to Promote Energy Efficiency Investments Standard as required by Section 532 of EISA, requires state commissions to consider whether to implement:

> (1) removing the throughput incentive and disincentives to energy efficiency;
>
> (2) providing utility incentives for successful management of energy efficiency programs;
>
> (3) including the impact of energy efficiency as one of the goals of retail rate design;
>
> (4) adopting rate designs that encourage energy efficiency;
>
> (5) allowing timely recovery of energy efficiency related costs; and
>
> (6) offering energy audits, demand-response programs, publicizing the benefits of home energy efficiency improvements and educating homeowners about Federal and State incentives.

The Commission concludes that no further determination is needed in response to PURPA Section 111(d)(17) for Applicants.

PURPA Section 111(d)(18), the Smart Grid Investments Standard, requires the Commission to consider and determine whether the following is appropriate to implement to carry out the purposes of PURPA:

(A) IN GENERAL – Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including --

(i) total costs;

(ii) cost-effectiveness;

(iii) improved reliability;

(iv) security;

(v) system performance; and

(vi) societal benefit.

(B) RATE RECOVERY – Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.

(C) OBSOLETE EQUIPMENT – Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

PURPA Section 111(d)(19), the Smart Grid Information Standard, requires the Commission to consider and determine whether it is appropriate that all electricity purchasers and other interested parties should be provided access to information from their electricity provider related to, among other things, time-based prices, usage, and sources of power and type of generation, with associated greenhouse gas emissions for each type of generation, to the extent such information is available on a cost-effective basis, so as to carry out the purposes of PURPA. The standard appears in EISA as follows:

> (A) STANDARD. – All electricity purchasers shall be provided direct access, in written or machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B).
>
> (B) INFORMATION. – Information provided under this section, to the extent practicable, shall include:
>
> > (i) PRICES. – Purchasers and other interested persons shall be provided with information on –
> >
> > > (I) time-based electricity process in the wholesale electricity market; and
> > >
> > > (II) time-based electricity retail prices or rates that are available to the purchasers.
> >
> > (ii) USAGE. – Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.
> >
> > (iii) INTERVALS AND PROJECTIONS – Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.
> >
> > (iv) SOURCES – Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be etermined, by type of

> generation, including greenhouse gas missions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.
>
> (C) ACCESS – Purchasers shall be able to access their own information at any time through the internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.

The Commission has established the appropriate avenues for monitoring smart grid activities and no greater ongoing activity is needed in response to PURPA sections 111(d)(18) and 111(d)(19).

B. KCPL Only (ER-2012-0174): Additional Resource Planning

The following matter relates to KCPL only, and not to GMO.

- The Commission is not ordering procedures and standards in addition to those already provided by law for examining the prudence of environmental protection measures at Montrose and La Cygne.

Sierra Club, OPC, and the consumer groups ask the Commission to order procedures and standards, related to environmental retrofits at coal-fired plant, in addition to those already existing at law.

Findings of Fact

1. When running a power plant costs more than the revenue it generates, it is time to consider retiring the plant. Retirement of coal-fired plants is common for several reasons. The cost of complying with environmental regulations are rising. Market prices for natural gas and wholesale electricity are declining. The availability of alternative resources like

renewable energy and energy efficiency are growing. Those trends make sales of electricity off-system less profitable.

2. KCPL owns 50 percent of the coal-fired La Cygne generating plant. The only other owner of La Cygne is Westar. That power plant has two units, one of which started operating in 1973 and the other of which started operating in 1977.

3. KCPL also owns Montrose Generating Station, which consists of three coal – fired generating units built in 1958, 1960, and 1964

4. To comply with environmental standards, KCPL is investing a highly confidential amount in Montrose and approximately $1.23 billion in La Cygne. Of that latter amount, Westar will pay 50 percent to KCPL when the work is done, which will be approximately June 2015. KCP&L's 2012 IRP filing addresses the economics of retrofitting coal units at La Cygne and Montrose versus retiring them.

Discussion, Conclusions of Law, and Ruling

In support of its proposed orders for more procedures and standards, Sierra Club alleges that retrofitting La Cygne and Montrose is economically inefficient, but the Commission will not pre-determine the prudence of those expenses.

Sierra Club also cites the possibility of rate shock because the Commission cannot include the retrofit costs in rates not until that work is done. That is because of an initiative passed in 1976:

> Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property

> before it is fully operational and used for service, is unjust and unreasonable, and is prohibited.[79]

That provision bars construction work in progress ("CWIP"), like the retrofit, from rate base and makes graduated accommodation nearly impossible. Sierra Club also cites the possibility of imprudent expenditures. On those bases, Sierra Club, OPC AARP, and the Consumers Council of Missouri ask the Commission to prescribe an ongoing formal procedure during retrofitting.

Sierra Club acknowledges the existence of the Integrated Resource Planning ("IRP") procedure, KCPL's informational meetings with Staff and OPC, and the Commission's periodic prudence reviews. Nevertheless, Sierra Club alleges that some kind of ongoing formal hearing procedure would benefit shareholders and customers. The cost of such proceedings to rate-payers does not figure into Sierra Club's proposal. Absent a full analysis of the effects on ratepayers, Sierra Club's proposals are unpersuasive as a matter of fact and policy. Moreover, no rulemaking, IRP, or prudence review is before the Commission in this contested case.

The Commission concludes that the proposed additional standards and procedures do not support safe and adequate service at just and reasonable rates, so the Commission will not order the proposed procedures or standards for KCPL in this contested case.

C. GMO Only (ER-2012-0175)

The following matters relate to GMO only, and not to KCPL.

- Crossroads: the Commission is updating, but not changing, the method of valuing amounts to include in MPS rate base, and exclude transmission costs

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[79] Section 393.135, RSMo 2000.

- Off-System Sales: the Commission is making no ruling because none is sought.
- FAC: The Commission is not changing the sharing percentage, ordering flow-through of both gains and losses for REC flow-through, excluding transmission costs, continuing current reporting, and ordering new tariff terminology.

i. Crossroads

The parties dispute the value for MPS rate base of the Crossroads as to physical plant, depreciation, accumulated tax set-off and transmission costs. The Commission already ruled on these issues in GMO's last general rate action ("previous rulings"), which was in File No. ER-2010-0356.[80] GMO asks to increase the amounts in rate base attributable to Crossroads. Dogwood Energy, LLC, ("Dogwood,") which owns a generating facility), and Staff oppose that claim. MECG, MEUG, and Ag Processing, Inc. a Cooperative ("Ag Processing," a customer) ask to reduce those amounts. No party has shown that the Commission should change its previous rulings. The Commission incorporates, as if fully set forth its findings of fact and conclusions of law from the previous rulings and recapitulates only the most salient facts relevant to Crossroads' valuation only as necessary to show how the movants for change have failed to meet their burden of proof.

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[80] *In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service*, *Report and Order*, issued May 4, 2011.

Generally. The following matters relate generally to both valuation and transmission costs.

Findings of Fact

1. GMO's MPS service area receives part of its power from Crossroads Energy Center ("Crossroads"), a generating facility in Clarksdale, Mississippi.

2. In the previous rulings, the Commission determined that the fair market value of Crossroads was $61.8 million before depreciation and deferred taxes.

3. In the previous rulings, the Commission denied the costs of transmitting power from Crossroads to MPS territory.

Discussion, Conclusions of Law, and Ruling

The parties may seek review of matters already determined under the previous rulings before the current Commission, which may alter those rulings.

> Every order or decision of the commission . . . shall continue in force either for a period which may be designated therein or until changed or abrogated by the commission [.[81]]

But even if GMO met its burden of proof, administrative and judicial economy would support a reservation of ruling in this report and order. That is because the previous rulings are pending before the Court of Appeals.[82] Departure from the previous rulings before the

[81] Section 386.490.2, RSMo 2000. Another standard of proof appears in the statutes for "[a]ll proceedings arising under the provisions of" chapter 386, RSMo: A "party . . . seeking to set aside any . . . order of said commission [must] show by clear and satisfactory evidence that the . . . order of the commission complained of is unreasonable or unlawful as the case may be. Section 386.430, RSMo 2000. Clear and satisfactory evidence is a standard higher than the preponderance of the evidence. *State ex rel. Taylor v. Anderson*, 254 S.W.2d 609, 615 (Mo. Div. 1, 1953). Missouri courts equate it with clear and convincing evidence. *Hackbarth v. Gibstine*, 182 S.W.2d 113, 118 (St.L. Ct. App. 1944). The Commission need not decide whether the higher standard applies because GMO did not meet the lower preponderance of evidence in addressing the previous rulings.

[82] Case No. WD75038, *KCPL&L v. Missouri Public Service Comm'n*.

Court of Appeals has reviewed them invites confusion and uncertainty to these matters for all involved.

Plant, Depreciation, Taxes. The parties dispute the value that Crossroads represents for MPS rate base, including physical plant, depreciation, and deferred taxes. GMO has not shown that GMO's proposed valuation best supports safe and adequate service at just and reasonable rates. The preponderance of the evidence shows the updated values as follows.

Findings of Fact

1. Crossroads is the property of the City of Clarksdale, Mississippi. GMO neither owns nor leases any part of Crossroads. GMO has a capital lease on the power generated at Crossroads that includes the duty to pay for, and the right to inspect, Crossroads operations.

2. GMO uses Crossroads power for peak demand in the summer. Crossroads runs less than half of the summer's days and has never run in the winter. Nevertheless, GMO pays for gas to be available in the winter.

3. The previous rulings recognized that Crossroads represents some value to GMO customers, and based valuation upon the market for the same technology, and on GPE's valuation of Crossroads in filings with the United States Securities and Exchange Commission ("SEC").[83]

4. In a Joint Proxy Statement/Prospectus and amendments filed with the SEC between May and August 2007, Aquila (GMO under its previous name and management)

[83] File No. ER-2010-0356, *Report and Order* page 96.

and GPE stated three times that the fair market value of Crossroads was $51.6 million. Aquila and GPE stated that they based the evaluation on sales of comparable assets.

5. The comparable assets were combustion turbines of the same type as those in Crossroads. Aquila Merchant installed the turbines in two Illinois facilities: Raccoon Creek and Goose Creek, both of which facilities it sold at a loss. Aquila Merchant (Aquila's unregulated affiliate) sold other turbines to utilities in Nebraska and Colorado at a loss. Aquila Merchant returned the last of those turbines to the manufacturer and, in so doing, surrendered to the manufacturer the deposit it had put down on that turbine. Those sales occurred between 2006 and 2008.

6. Aquila Merchant also tried to sell Crossroads, but could come to terms with no buyer, so it transferred Crossroads to a subsidiary of Aquila. Aquila became financially distressed and GPE bought it, thus acquiring Crossroads. GPE also tried, but failed, to sell Crossroads to an outside buyer. GPE sold Crossroads to Aquila, which it later renamed GMO.

7. Using the same valuation principles as in the previous rulings, the value of Crossroads updated as of August 31, 2012, is $62,609,430. Based on a fair market value of Crossroads at $62,609,430, the applicable depreciation is $10,033,437 and the deferred tax due on Crossroads is $4,333,301.

Discussion, Conclusions of Law, and Ruling

The parties agree generally that depreciation and accumulated taxes must follow the valuation of physical plant.

GMO argues that Crossroads' rate base value is GMO's depreciated net original cost, sometimes called depreciated book value, of $82.7 million. In support, GMO offers case law from another jurisdiction,[84] which states that all evidence bearing on value is relevant, but pre-dating the Commission regulation that adopts USoA.[85] USoA defines cost as beginning with the amount incurred by the entity that first put the asset to public service. GMO relies on Aquila's building costs, the price in a transaction between affiliated entities GPE and GMO, and an estimate expressly designed to justify the price paid in that transaction, none of which are persuasive.

Holding GMO to those statements nonetheless, MECG suggests that, if the Commission departs from its previous rulings, the Commission should embrace the values that GPE and GMO (then Aquila) assigned in its filings with the SEC.

MECG also cites the Commission's affiliate transaction rule, which sets the cost of goods from an affiliate at the lesser of either (i) fully distributed cost or (ii) fair market price.[86] Staff emphasizes fair market price as determined in the previous rulings. Then, as now, Staff argues, the fair market price is determinable from the sales of the comparable Raccoon Creek and Goose Creek facilities. The Commission stated:

> The ten 75 MW General Electric model 7EA combustion turbines installed at Raccoon Creek and Goose Creek that Aquila Merchant sold to AmerenUE in 2006 are ten of the eighteen combustion turbines Aquila Merchant bought at the same time. Four of those eighteen were installed at Crossroads. The turbines sold at an average installed cost of \$205.88 per kW. Based on that average installed cost of \$205.88 per kW, the 300 MW of combustion turbines at Crossroads would have an installed cost of \$61.8 million.[87]

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[84] _Springfield Gas & Elec. Co. v. PSC,_ 10 F.2d 252, 255 (W.D. Mo. 1925); and _State ex rel. Missouri Water Co. v. PSC_, 308 S.W.2d 704, 717 (Mo. 1957).

[85] 4 CSR 240-20-030.

[86] 4 CSR 240-20.015(2)(A).

[87] File No. ER-2010-0356, *Report and Order*, page 94 (citations omitted).

Staff provides an analysis based on that method in direct testimony on its true-up accounting schedules. That amount is less than GMO's cost figure and therefore controls. In this regard, the arguments for maintaining the status quo analysis rebuts GMO's claim for a higher amount in rate base.

Finally, MEUG and Ag Processing succinctly suggest that the MPS rate base value of Crossroads is zero. The argument has an elegant simplicity. After all, GMO does not own or lease Crossroads. And constructing a surrogate value for Crossroads is not the only way to account for the power that GMO buys from the City of Clarksdale, Mississippi. But the evidence does not weigh in that direction. The Commission rejected Staff's argument to disallow Crossroads from rate base entirely in the previous rulings[88]because some benefit from distant Mississippi does reach the MPS customers and that remains true today. Therefore, the Commission will not value Crossroads at zero.

Crossroads is a relic of the failed utility Aquila. A full recital of Aquila's tortured history is unnecessary to the Commission's rulings,[89] because it only raises the issue of how long the Commission will visit the sins of the predecessor on the successor. It is true that GMO is the same legal entity as Aquila, but it is also true that management is different.

Therefore, the Commission will order that the value of Crossroads for GMO's MPS rate base shall be $62,609,430 without transmission cost. At that value, GMO and Staff agree, the accumulated depreciation is $10,033,437 and the accumulated deferred taxes are $4,333,301. Those values best support safe and adequate service at just and

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[88] File No. ER-2010-0356, *Report and Order*, page 99.

[89] MECG spares its readers no gruesome detail. *Initial Post-Hearing Brief of [MECG] (GMO Issues)*, pages 59-73.

reasonable rates for MPS, so the Commission will order those amounts to be included in GMO's MPS rate base.

Transmission Costs. GMO asks the Commission to depart from the previous rulings and include in MPS rates the costs of transmitting power from Crossroads to MPS territory but it has not carried its burden of proof on that claim.

<u>Findings of Fact</u>

1. Crossroads is 500 miles from GMO's MPS territory.

2. Between the territory of MPS and Crossroads are the territories of regional transmission organizations ("RTOs"). RTOs collect payment for the transmission of power through their territories. GMO does not belong to all those RTOs so GMO must pay higher fees for transporting power than to an RTO of which GMO is a member.

3. There are generating facilities closer, including Dogwood's facility and the South Harper plant. Even though Crossroads provides power for GMO only during half of the days in the summer, GMO pays about $5.2 million to transmit power from Crossroads all year round. The high cost of transmission is not outweighed by lower fuel costs in Mississippi.

<u>Discussion, Conclusions of Law, and Ruling</u>

GMO has not carried its burden of proof on transmission costs. GMO alleges that the lower price of fuel in Mississippi outweighs the cost of transmission. The Commission has found that the evidence preponderates otherwise.

GMO also argues that the Commission must include transmission costs because FERC has approved a rate for that service. In support, GMO cites opinions providing that the Commission cannot nullify FERC's rate or any other FERC ruling.

But as Dogwood explains, and Staff and MECG agree, those opinions do not bar the Commission from determining the prudence of buying power from Crossroads. For example:

> Without deciding this issue, we may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower cost power is available elsewhere, even though the higher cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price.* [[90]]

In other words, FERC's rate-setting for a facility requires neither the purchase of power, nor approval of that purchase, from that facility.

Moreover, in the presence of a FERC-approved rate, the courts have opined that review of cost prudence remains within the Commission's jurisdiction.

> Regarding the states' traditional power to consider the prudence of a retailer's purchasing decision in setting retail rates, we find no reason why utilities must be permitted to recover costs that are imprudently incurred; those should be borne by the stockholders, not the rate payers. Although Nantahala underscores that a state cannot independently pass upon the reasonableness of a wholesale rate on file with FERC, it in no way undermines the long-standing notion that a state commission may legitimately inquire into whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another source. [[91]]

And to recognize the marginal value of purchased power from Crossroads does not constitute an endorsement of its inflated cost.

Therefore, the Commission concludes that including the Crossroads transmission costs does not support safe and adequate service at just and reasonable rates, and the Commission will deny those costs.

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[90] Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953, 972 (1986).

ii. Off-System Sales Margins

Staff expresses concerns at the amount of negative margins in GMO's off-system sales compared to other regulated electric companies and asks the Commission to urge GMO to do better. GMO promises to try. No party seeks any relief on this matter any longer so the Commission will order none, and no further findings of fact and conclusions of law are required..

iii. Fuel Adjustment Clause

The fuel and purchased power adjustment clause ("FAC") is, essentially, a device by which GMO can pass increases or decreases in fuel or purchased power costs to its customers without a general rate action.

AARP and CCoMO argue for an end to GMO's FAC, and all FACs, on policy grounds. But the General Assembly has determined that the Commission shall have discretion to order an FAC. AARP and CCoMO have not shown that an FAC for GMO makes safe and adequate service at just and reasonable rates impossible, so the Commission will not grant AARP and GMO's request.

For GMO's FAC, the Commission is ordering:

- No change in the sharing mechanism.
- Flow-through of revenues from excess RECs.
- Specific exclusion of Crossroads transmission costs.
- Continued reporting.
- New tariff language.

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[91] *Kentucky W. Virginia Gas Co. v. Pennsylvania Pub. Util. Comm'n*, 837 F.2d 600, 609 (3d Cir. 1988).

Sharing Percentages. The sharing percentage splits fuel and purchased power price fluctuations between GMO and its customers.

Findings of Fact

1. The essence of the current FAC is that fluctuations in the price of fuel and purchased power, up or down from an established baseline, pass through to GMO customers at 95%, the remaining 5% is GMO's to pay or retain.

2. The record shows no incident of imprudent GMO purchasing.

3. The 95%-5% sharing has been enough incentive for GMO to maintain prudence in its purchases.

Discussion, Conclusions of Law, and Ruling

In simplified terms, an FAC measures fluctuations in the price that GMO pays for fuel and purchased power and allows GMO to pass such fluctuations through to customers between general rate actions:

> 1. . . . periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. [[92]]

An FAC must not compromise the opportunity to earn a fair rate of return; and include periodic true-ups, prudence reviews, refunds, and review during a general rate action.[93] The statutes also allow incentives to look for lower prices:

> The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency

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[92] Section 386.266.1, RSMo Supp. 2012.

[93] Section 386.266.1, RSMo Supp. 2012.

> and cost-effectiveness of its fuel and purchased-power procurement activities. [[94]]

Among those incentives is the sharing percentage.

Essentially, under the current sharing percentage, of any price decrease, GMO gets to keep 5% and the rest passes on to customers in the form of a rate decrease. And of any price increase, GMO has to pay 5% and the rest passes on to customers in the form of a rate increase. Staff proposes an 85%-15% split.

In support, Staff alleges that the current split does not give GMO enough incentive to seek the best prices. In support, Staff offers evidence related to GMO's satisfaction with the current split, its transactions with KCPL, and its use of short-term purchase contracts. None of that is persuasive because Staff has cited no incident of imprudent purchasing. "[M]ere speculations . . . do not demonstrate that the Commission act[s] unreasonably in permitting this particular FAC."[95]

The Commission concludes that GMO's current FAC sharing percentages of 95%-5% better support safe and adequate service at just and reasonable rates than 85%-15%, so the Commission will order GMO's current percentages for GMO's FAC.

REC Flow-Through. Staff proposes that, if GMO has more renewable energy certificates than it needs for compliance with the renewable energy laws[96] ("excess RECs"), and GMO sells those excess RECs, the proceeds must pass

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[94] Section 386.266.1, RSMo Supp. 2012.

[95] *State ex rel. Noranda Aluminum, Inc. v. Pub. Serv. Comm'n of State*, 356 S.W.3d 293, 314 (Mo. App., S.D. 2011).

through the FAC like a fuel price decrease. GMO proposes that the costs of those RECs pass through the FAC, too, like a fuel price increase. Staff's proposal is consistent with law and GMO's proposal is contrary to law as follows.

Findings of Fact

1. When GMO customers pay their bills, GMO uses that money for a variety of purposes, including purchasing power. GMO has agreements to purchase power from sellers of renewable energy, including wind and methane. Purchases or use of power from those sources generate renewable energy certificates ("RECs").

2. RECs are a measure of compliance with laws promoting the use of renewable energy. When purchasing power, the REC does not cost extra. If GMO has more RECs than it needs to satisfy the requirements of law ("excess RECs"), it is prudent practice to sell them.

3. Because GMO customers paid the money that generated the REC, if GMO sells the REC, it sells something that the customers bought.

Discussion, Conclusions of Law, and Ruling

The FAC law provides that the Commission may use GMO's FAC to encourage efficient fuel and power purchasing:

> The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. [[97]]

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[96] Section 393.1030, RSMo Supp. 2012; and Commission regulation 4 CSR 240-20.100.

[97] Section 386.266.1, RSMo Supp. 2012.

Making sure that GMO does not retain the revenue from excess RECs constitutes an incentive to purchase renewable power efficiently.

GMO proposes to pass the costs of excess RECs on to customers through the FAC but Staff cites 4 CSR 240-20.100(6)(A)16, which bars GMO's proposal:

> RES compliance costs shall only be recovered through an RESRAM or as part of a general rate proceeding and shall not be considered for cost recovery through an environmental cost recovery mechanism or fuel adjustment clause or interim energy charge.

That law bars the pass-through of REC costs through GMO's FAC. Even without that regulation, GMO's proposal constitutes a disincentive to purchase renewable power efficiently.

Staff's proposal supports safe and adequate service at just and reasonable rates, so the Commission will order excess REC revenues to pass through the FAC, but not the costs of RECs.

Crossroads Transmission. Several parties ask the Commission to order that GMO's FAC tariff sheets state expressly that GMO's FAC excludes transmission costs related to the Crossroads. Insofar as the Commission has determined that no transmission costs from Crossroads will enter GMO's MPS rates, there is no further dispute, and no further findings of fact and conclusions of law are required. The Commission will order GMO's FAC clarified to state that GMO's FAC excludes transmission costs related to Crossroads.

Additional Reporting. Staff and GMO dispute only whether the Commission should order the reporting in Appendix D to continue. GMO objects only to the implication that it has failed to deliver something demanded of it. That dispute requires no findings of fact and no conclusions of law because no party seeks relief on it. Therefore, without any finding that GMO has failed to do anything listed in Appendix D, the Commission will order GMO to do, or continue to do, the reporting listed in Appendix D.

Changes to FAC Tariff Sheet Terminology. Staff asks the Commission to order GMO's FAC tariff modified to include replacement sheets that, without making substantive changes, employ standard terminology proposed for all of the Missouri regulated electrical corporations FACs. No party opposes that request so the Commission makes no findings of fact and no conclusions of law. Therefore, the Commission will order that any FAC tariff sheets filed pursuant to this report and order shall employ the language sought by Staff as set forth in the revised exemplar FAC tariff sheets.

V. Compliance Tariffs

For those reasons, the Commission will reject the tariffs and order the filing of new tariff sheets in compliance with this report and order ("compliance tariffs"). The parties request approval of such compliance tariffs effective on January 26, 2013. To accommodate that request, the Commission will expedite the effective date for this decision,[98] the filing date for compliance tariffs, and the filing date for Staff's recommendation on the compliance tariffs.

THE COMMISSION ORDERS THAT:

1. The provisions of the following documents are incorporated into this order as if fully set forth, either as the Commission's order or as a consent order, as described in the body of this report and order:

---

[98] Section 386.490.2, RSMo 2000.

a. In File Nos. ER-2012-0174 and ER-2012-0175:

Document	Filed (2012)
Partial Nonunanimous Stipulation and Agreement Respecting Kansas City Water Services Department and Airport Issues	October 19
Non-Unanimous Stipulation and Agreement as to Certain Issues	October 19
Non-Unanimous Stipulation and Agreement Regarding Low-Income Weatherization and Withdrawal of Objection and Request for Hearing	October 26
Non-Unanimous Stipulation and Agreement Regarding Praxair, Inc., Ag Processing Inc a Cooperative and the Midwest Energy Users' Association's Objection and Withdrawal of Objection and Request for Hearing	October 29

b. In File No. ER-2012-0174:

Second Non-Unanimous Stipulation and Agreement as to Certain Issues	November 8

c. In File No. ER-2012-0175:

Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design	October 29
Second Non-Unanimous Stipulation and Agreement as to Certain Issues	November 8

2. The first and second motions to strike, as described in the body of this report and order, are denied without ruling on the merits. The third motion to strike, as described in the body of this report and order, is denied.

3. The *Motion to Update Reply Brief* and *Motion to Provide Supplemental Authorities*, including the additional orders filed on December 26, 2012, are granted.

4. All other rulings described in the body of this report and order are made in, and incorporated into, this paragraph as if fully set forth; and, on those grounds, the tariff sheets listed in Appendix E are rejected.

5. No later than January 16, 2013:

a. Kansas City Power and Light Company ("KCPL") shall file a new tariff consistent with the rulings described in this report and order ("compliance tariff") under File No. ER-2012-0174; and

b. KCPL Greater Missouri Operations Company ("GMO") shall file a compliance tariff in File No. ER-2012-0175.

6. No later than January 24, 2013, the Commission's staff shall file a recommendation on the compliance tariffs.

7. No later than February 5, 2013, the information required under Section 393.275.1, RSMo 2000, and 4 CSR 240-10.060 shall be filed:

a. By KCPL in File No. ER-2012-0174; and

b. By GMO in File No. ER-2012-0175

8. This order shall become effective on January 9, 2013.

BY THE COMMISSION

(S E A L)

Shelley Brueggemann

Shelley Brueggemann
Acting Secretary

Gunn, Chm., Jarrett, Kenney, and
Stoll, CC., concur;
and certify compliance with the
provisions of Section 536.080, RSMo.

Dated at Jefferson City, Missouri,
on this 9th day of January, 2013

Appendix A: Appearances

Party	Counsel	Counsel's Address
i. Applicants		
Kansas City Power & Light Company; and KCP&L Greater Missouri Operations Company	James M. Fischer	101 Madison Street Jefferson City, Missouri 65101
	Lisa A. Gilbreath Karl Zobrist	4520 Main, Suite 1100 Kansas City, MO 64111
	Heather A. Humphrey Roger W. Steiner	1200 Main, PO Box 418679 Kansas City, MO 64141-9679
	Charles W. Hatfield	230 W. McCarty Street Jefferson City, MO 65101-1553
ii. Parties under 4 CSR 240-2.010(10)		
Staff of the Commission	Kevin Thompson Steven Dottheim Nathan Williams Jeff Keevil Sarah Kliethermes Annette Slack Tanya Alm John Borgmeyer	P.O. Box 360 200 Madison Street, Suite 800 Jefferson City, MO 65102
Office of the Public Counsel	Lewis R. Mills, Jr. Christina Baker	200 Madison Street, Suite 650 P.O. Box 2230 Jefferson City, MO 65102
iii. Intervenors		
AARP; and Consumers Council of Missouri	John B. Coffman	871 Tuxedo Blvd. St. Louis, MO 63119-2044
AG Processing, Inc. a Cooperative and Midwest Energy Users' Group[99]	Stuart Conrad	3100 Broadway Suite 1209 Kansas City, MO 64111
City of Kansas City, Missouri	Mark W. Comley	601 MonRoE Street., Suite 301 Jefferson City, MO

[99] Which sometimes calls itself Midwest Energy Users' Association.

		65102-0537
Dogwood Energy, LLC	Carl J. Lumley	130 S. Bemiston, Ste 200 St. Louis, MO 63105
Federal Executive Agencies	Steven E. Jones	1104 SE Talonia Drive Lee's Summit, MO 64081
Midwest Energy Consumers Group	David Woodsmall	807 Winston Court Jefferson City, MO 65101
Midwest Energy Users' Association-Kansas City[100]	Reed J. Bartels	3100 Broadway, Suite 1209
	Jeremiah D. Finnegan	1200 Penntower Office Center 3100 Broadway Kansas City, MO 64111
Missouri Department of Natural Resources	Jessica L. Blome Mary Ann Young	221 W. High Street P.O. Box 899 Jefferson City, MO 65102
The Empire District Electric Company	Diana C. Carter	312 East Capitol P.O. Box 456 Jefferson City, MO 65102
Southern Union Company	Dean L. Cooper	312 East Capitol P.O. Box 456 Jefferson City, MO 65102
	Todd J. Jacobs	3420 Broadway Kansas City, MO 64111
Missouri Industrial Energy Consumers	Diana M. Vuylsteke John R. Kindschuh	211 N. Broadway, Suite 3600 St. Louis, MO 63102
Natural Resources Defense Council; and Sierra Club	Henry B. Robertson	705 Olive Street, Suite 614 St. Louis, MO 63101
	Thomas Cmar	5042 N. Leavitt St., Ste 1 Chicago, IL 60625
	Shannon Fisk	1617 John F. Kennedy Blvd. Suite 1675 Philadelphia, PA 19103
Earth Island Institute d/b/a Renew Missouri	Shannon Fisk	1617 John F. Kennedy Blvd Suite 1675, Philadelphia, PA 19103
Union Electric Company	James B. Lowery	111 South Ninth St. Suite 200, P.O. Box 918 Columbia, MO 65205-0918
	Thomas M. Byrne	1901 Chouteau Avenue P.O. Box 66149 (MC 1310) St. Louis, MO 63166-6149
United States Air Force-	Steven E. Jones	1104 SE Talonia Drive

[100] Which also sometimes calls itself Midwest Energy Users' Association.

Whiteman AFB and other affected federal agencies		Lee's Summit, MO 64081
	Capt. Samuel T. Miller	139 Barnes Drive, Suite 1 Tyndall Air Force Base, FL 32403
United States Department of Energy and other affected federal agencies	Therese LeBlanc	2000 E. 95th St. P.O. Box 419159 Kansas City, MO 64141
	Arthur Perry Bruder	1000 Independence Ave. SW Washington, DC 20585
Missouri Joint Municipal Electrical Utility Commission	Douglas L. Healy	939 Boonville, Suite A Springfield, Missouri 65802

Senior Regulatory Law Judge: Daniel Jordan.

Appendix B: Briefs and Statements after Evidentiary Hearing

i. Initial Briefs

Party	ER-2012-0174 and ER2012-0175	
Kansas City Power & Light Company; and KCP&L Greater Missouri Operations Company	Proposed Findings of Fact and Conclusions of Law of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company; and Initial Post-Hearing Brief of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company	
Staff	Staff's Initial Brief	
Office of the Public Counsel	Initial Brief of the Office of the Public Counsel	
AARP	Initial Brief of AARP	
Consumers Council of Missouri	Initial Brief of Consumers Council of Missouri	
Federal Executive Agencies[101]	The Federal Executive Agencies' Post-Hearing Brief on Rate of Return and Capital Structure	
Missouri Industrial Energy Consumers	Initial Brief of Missouri Industrial Energy Consumers	
	ER-2012-0174	**ER-2012-0175**
Midwest Energy Consumers' Group	Initial Posthearing Brief of Midwest Energy Consumers' Group (KCPL Issues)	Initial Posthearing Brief of Midwest Energy Consumers' Group (GMO Issues)
Southern Union Company	Initial Brief of Southern Union Company d/b/a Missouri Gas Energy	Initial Brief of Southern Union Company d/b/a Missouri Gas Energy
	ER-2012-0174	
Sierra Club	Brief of Sierra Club	
Midwest Energy Users' Association-Kansas City	Post-Hearing Brief Midwest Energy Users' Association	
Praxair, Inc.	Praxair, Inc. Statement in Lieu of Initial Brief	
	ER-2012-0175	
Midwest Energy Users' Group and AG Processing, Inc. a Co-Operative	Initial Brief on Limited Issues by Midwest Energy Users' Group and AG Processing, Inc. a Co-Operative	
Dogwood Energy, LLC	Proposed Findings of Fact and Conclusions of Law; and Brief	
Federal Executive Agencies[102]	The Federal Executive Agencies' Post-Hearing Brief on Transmission Tracker	

[101] Filed by counsel for the United States Department of Energy.

[102] Filed by counsel for the United States Air Force.

ii. Reply Briefs

Party	ER-2012-0174 and ER2012-0175
Kansas City Power & Light Company; and KCP&L Greater Missouri Operations Company	Reply Post-Hearing Brief of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company
Staff	Staff's Reply Brief
Office of the Public Counsel	Post-Hearing Reply Brief of the Office of the Public Counsel
Federal Executive Agencies	The Federal Executive Agencies' Reply Brief on Rate of Return and Capital Structure
Missouri Industrial Energy Consumers	Reply Brief of the Missouri Industrial Energy Consumers
Midwest Energy Consumers' Group	Reply Posthearing Brief of Midwest Energy Consumers' Group; and Proposed Findings of Fact and Conclusions of Law
Southern Union Company	Reply Brief of Southern Union Company d/b/a Missouri Gas Energy
	ER-2012-0174
Sierra Club	Reply Brief of Sierra Club
Midwest Energy Users' Association-Kansas City	Post-Hearing Reply Brief Midwest Energy Users' Association-Kansas City
	ER-2012-0175
Dogwood Energy, LLC	Dogwood Energy, LLC's Reply Brief

Appendix C: USoA Accounts for Other Regulatory Assets and Liabilities

182.3 Other regulatory assets.

A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (See Definition No. 31.)

B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services. When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, account 407.4, regulatory credits, shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred, except all regulatory assets established through the use of account 407.4 shall be charged to account 407.3, Regulatory debits, concurrent with the recovery in rates.

C. If rate recovery of all or part of an amount included in this account is disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, or Account 435, Extraordinary Deductions, in the year of the disallowance.

D. The records supporting the entries to this account shall be kept so that the utility can furnish full information as to the nature and amount of each regulatory asset included in this account, including justification for inclusion of such amounts in this account.

18 C.F.R. § 201

254 Other regulatory liabilities.

A. This account shall include the amounts of regulatory liabilities, not includible in other accounts, imposed on the utility by the ratemaking actions of regulatory agencies. (See Definition No. 30.)

B. The amounts included in this account are to be established by those credits which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that: Such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services; or refunds to customers, not provided for in other accounts, will be required. When specific identification of the particular source of the regulatory liability cannot be made or when the liability arises from revenues collected pursuant to tariffs on file at a regulatory agency, account 407.3, regulatory debits, shall be debited. The amounts recorded in this account generally are to be credited to the same account that would have been credited if included in income when earned except: All regulatory liabilities established through the use of account 407.3 shall be credited to account 407.4, regulatory credits; and in the case of refunds, a cash account or other appropriate account should be credited when the obligation is satisfied.

C. If it is later determined that the amounts recorded in this account will not be returned to customers through rates or refunds, such amounts shall be credited to Account 421, Miscellaneous Nonoperating Income, or Account 434, Extraordinary Income, as appropriate, in the year such determination is made.

D. The records supporting the entries to this account shall be so kept that the utility can furnish full information as to the nature and amount of each regulatory liability included in this account, including justification for inclusion of such amounts in this account.

18 C.F.R. § 201

Appendix D: Additional FAC Reporting

- As part of the information GMO submits when it files a tariff modification to change its FAC rate, GMO includes GMO's calculation of the interest included in the proposed rate;
- GMO maintains at GMO's corporate headquarters or at some other mutually agreed upon place within a mutually agreed upon time for review, a copy of each and every nuclear fuel, coal and transportation contract GMO has that is, or was, in effect for the previous four years;
- Within 30 days of the effective date of each and every nuclear fuel, coal and transportation contract GMO enters into, GMO provides both notice to the Staff of the contract and opportunity to review the contract at GMO's corporate headquarters or at some other mutually agreed upon place;
- GMO maintains at GMO's corporate headquarters or provides at some other mutually agreed upon place within a mutually agreed upon time, a copy for review of each and every natural gas contract GMO has that is in effect;
- Within 30 days of the effective date of each and every natural gas contract GMO enters into, GMO provides both notice to the Staff of the contract and opportunity for review of the contract at GMO's corporate headquarters or at some other mutually agreed upon place;
- GMO provides a copy of each and every GMO 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 GMO hedging policy, GMO provides a copy of the changed hedging policy for Staff to retain;
- GMO provides a copy of GMO's internal policy for participating in the SPP, including any GMO sales or purchases from that market that are in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain; and
- If GMO revises any internal policy for participating in the SPP, within 30 days of that revision, GMO provides a copy of the revised policy with the revisions identified for Staff to retain.

Appendix E: Tariff Sheets Rejected

The tariff sheets rejected are:

i. In File No. ER-2012-0174, the tariff assigned tracking number YE-2012-0404:

Kansas City Power & Light Company
PSC Mo. No. 7
11th Revised Sheet No. TOC-1, canceling 10th Revised Sheet No. TOC-1
7th Revised Sheet No. 5A, canceling 6th Revised Sheet No. 5A
7th Revised Sheet No. 5B, canceling 6th Revised Sheet No. 5B
2nd Revised Sheet No. 5C, canceling 1st Revised Sheet No. 5C
2nd Revised Sheet No. 6, canceling 1st Revised Sheet No. 6
7th Revised Sheet No. 8, canceling 6th Revised Sheet No. 8
6th Revised Sheet No. 8A, canceling 5th Revised Sheet No. 8A
7th Revised Sheet No. 9A, canceling 6th Revised Sheet No. 9A
7th Revised Sheet No. 9B, canceling 6th Revised Sheet No. 9B
2nd Revised Sheet No. 9E, canceling 1st Revised Sheet No. 9E
7th Revised Sheet No. 10A, canceling 6th Revised Sheet No. 10A
7th Revised Sheet No. 10B, canceling 6th Revised Sheet No. 10B
7th Revised Sheet No. 10C, canceling 6th Revised Sheet No. 10C
2nd Revised Sheet No. 10E, canceling 1st Revised Sheet No. 10E
7th Revised Sheet No. 11A, canceling 6th Revised Sheet No. 11A
7th Revised Sheet No. 11B, canceling 6th Revised Sheet No. 11B
7th Revised Sheet No. 11C, canceling 6th Revised Sheet No. 11C
2nd Revised Sheet No. 11E, canceling 1st Revised Sheet No. 11E
7th Revised Sheet No. 14A, canceling 6th Revised Sheet No. 14A
7th Revised Sheet No. 14B, canceling 6th Revised Sheet No. 14B
7th Revised Sheet No. 14C, canceling 6th Revised Sheet No. 14C
2nd Revised Sheet No. 14E, canceling 1st Revised Sheet No. 14E
7th Revised Sheet No. 17A, canceling 6th Revised Sheet No. 17A
3rd Revised Sheet No. 17D, canceling 2nd Revised Sheet No. 17D
7th Revised Sheet No. 18A, canceling 6th Revised Sheet No. 18A
7th Revised Sheet No. 18B, canceling 6th Revised Sheet No. 18B
7th Revised Sheet No. 18C, canceling 6th Revised Sheet No. 18C
3rd Revised Sheet No. 18E, canceling 2nd Revised Sheet No. 18E
7th Revised Sheet No. 19A, canceling 6th Revised Sheet No. 19A
7th Revised Sheet No. 19B, canceling 6th Revised Sheet No. 19B
7th Revised Sheet No. 19C, canceling 6th Revised Sheet No. 19C
3rd Revised Sheet No. 19D, canceling 2nd Revised Sheet No. 19D
7th Revised Sheet No. 20C, canceling 6th Revised Sheet No. 20C
1st Revised Sheet No. 20E, canceling Original Sheet No. 20E
2nd Revised Sheet No. 24, canceling 1st Revised Sheet No. 24
12th Revised Sheet No. 24A, canceling 11th Revised Sheet No. 24A
3rd Revised Sheet No. 25D, canceling 2nd Revised Sheet No. 25D
3rd Revised Sheet No. 26D, canceling 2nd Revised Sheet No. 26D

6th Revised Sheet No. 28B, canceling 5th Revised Sheet No. 28B
2nd Revised Sheet No. 28D, canceling 1st Revised Sheet No. 28D
2nd Revised Sheet No. 29D, canceling 1st Revised Sheet No. 29D
7th Revised Sheet No. 30, canceling 6th Revised Sheet No. 30
1st Revised Sheet No. 30A, canceling Original Sheet No. 30A
7th Revised Sheet No. 33, canceling 6th Revised Sheet No. 33
3rd Revised Sheet No. 33B, canceling 2nd Revised Sheet No. 33B
7th Revised Sheet No. 35, canceling 6th Revised Sheet No. 35
7th Revised Sheet No. 35A, canceling 6th Revised Sheet No. 35A
7th Revised Sheet No. 35B, canceling 6th Revised Sheet No. 35B
7th Revised Sheet No. 35C, canceling 6th Revised Sheet No. 35C
7th Revised Sheet No. 36, canceling 6th Revised Sheet No. 36
7th Revised Sheet No. 36A, canceling 6th Revised Sheet No. 36A
7th Revised Sheet No. 36B, canceling 6th Revised Sheet No. 36B
7th Revised Sheet No. 37, canceling 6th Revised Sheet No. 37
7th Revised Sheet No. 37A, canceling 6th Revised Sheet No. 37A
7th Revised Sheet No. 37B, canceling 6th Revised Sheet No. 37B
7th Revised Sheet No. 37C, canceling 6th Revised Sheet No. 37C
7th Revised Sheet No. 37D, canceling 6th Revised Sheet No. 37D
7th Revised Sheet No. 37E, canceling 6th Revised Sheet No. 37E
7th Revised Sheet No. 37F, canceling 6th Revised Sheet No. 37F
7th Revised Sheet No. 37G, canceling 6th Revised Sheet No. 37G
7th Revised Sheet No. 45, canceling 6th Revised Sheet No. 45
7th Revised Sheet No. 45A, canceling 6th Revised Sheet No. 45A
1st Revised Sheet No. 43Z, canceling Original Sheet No. 43Z
1st Revised Sheet No. 43Z.1, canceling Original Sheet No. 43Z.1
1st Revised Sheet No. 43Z.2, canceling Original Sheet No. 43Z.2
1st Revised Sheet No. 43Z.3, canceling Original Sheet No. 43Z.3
1st Revised Sheet No. 43AQ, canceling Original Sheet No. 43AQ
1st Revised Sheet No. 50, canceling Original Sheet No. 50.

ii. In File No. ER-2012-0175, the tariff assigned tracking number YE-2012-0405.

KCP&L Greater Missouri Operations Company
PSC Mo. No. 1, Electric Rates
5th Revised Sheet No. 1, canceling 4th Revised Sheet No.1
6th Revised Sheet No. 18, canceling 5th Revised Sheet No. 18
6th Revised Sheet No. 19, canceling 5th Revised Sheet No. 19
6th Revised Sheet No. 21, canceling 5th Revised Sheet No. 21
6th Revised Sheet No. 22, canceling 5th Revised Sheet No. 22
6th Revised Sheet No. 23, canceling 5th Revised Sheet No. 23
6th Revised Sheet No. 24, canceling 5th Revised Sheet No. 24
6th Revised Sheet No. 25, canceling 5th Revised Sheet No. 25
6th Revised Sheet No. 28, canceling 5th Revised Sheet No. 28
6th Revised Sheet No. 29, canceling 5th Revised Sheet No. 29
6th Revised Sheet No. 31, canceling 5th Revised Sheet No. 31

6th Revised Sheet No. 34, canceling 5th Revised Sheet No. 34
6th Revised Sheet No. 35, canceling 5th Revised Sheet No. 35
6th Revised Sheet No. 41, canceling 5th Revised Sheet No. 41
6th Revised Sheet No. 42, canceling 5th Revised Sheet No. 42
6th Revised Sheet No. 43, canceling 5th Revised Sheet No. 43
6th Revised Sheet No. 44, canceling 5th Revised Sheet No. 44
6th Revised Sheet No. 47, canceling 5th Revised Sheet No. 47
6th Revised Sheet No. 48, canceling 5th Revised Sheet No. 48
6th Revised Sheet No. 50, canceling 5th Revised Sheet No. 50
5th Revised Sheet No. 51, canceling 4th Revised Sheet No. 51
5th Revised Sheet No. 52, canceling 4th Revised Sheet No. 52
5th Revised Sheet No. 53, canceling 4th Revised Sheet No. 53
5th Revised Sheet No. 54, canceling 4th Revised Sheet No. 54
5th Revised Sheet No. 56, canceling 4th Revised Sheet No. 56
5th Revised Sheet No. 57, canceling 4th Revised Sheet No. 57
6th Revised Sheet No. 60, canceling 5th Revised Sheet No. 60
6th Revised Sheet No. 61, canceling 5th Revised Sheet No. 61
5th Revised Sheet No. 66, canceling 4th Revised Sheet No. 66
5th Revised Sheet No. 67, canceling 4th Revised Sheet No. 67
5th Revised Sheet No. 68, canceling 4th Revised Sheet No. 68
5th Revised Sheet No. 70, canceling 4th Revised Sheet No. 70
5th Revised Sheet No. 71, canceling 4th Revised Sheet No. 71
5th Revised Sheet No. 74, canceling 4th Revised Sheet No. 74
5th Revised Sheet No. 76, canceling 4th Revised Sheet No. 76
5th Revised Sheet No. 79, canceling 4th Revised Sheet No. 79
5th Revised Sheet No. 80, canceling 4th Revised Sheet No. 80
6th Revised Sheet No. 88, canceling 5th Revised Sheet No. 88
6th Revised Sheet No. 89, canceling 5th Revised Sheet No. 89
5th Revised Sheet No. 90, canceling 4th Revised Sheet No. 90
6th Revised Sheet No. 91, canceling 5th Revised Sheet No. 91
6th Revised Sheet No. 92, canceling 5th Revised Sheet No. 92
4th Revised Sheet No. 93, canceling 3rd Revised Sheet No. 93
6th Revised Sheet No. 95, canceling 5th Revised Sheet No. 95
5th Revised Sheet No. 103, canceling 4th Revised Sheet No. 103
5th Revised Sheet No. 104, canceling 4th Revised Sheet No. 104
1st Revised Sheet No. 127.6, canceling Original Sheet No. 127.6
1st Revised Sheet No. 127.7, canceling Original Sheet No. 127.7
1st Revised Sheet No. 127.8, canceling Original Sheet No. 127.8
1st Revised Sheet No. 127.9, canceling Original Sheet No. 127.9
Original Sheet No. 127.11
Original Sheet No. 127.12
Original Sheet No. 127.13
Original Sheet No. 127.14
Original Sheet No. 127.15
1st Revised Sheet No. 143, canceling Original Sheet No. 143

KCP&L Greater Missouri Operations Company
PSC Mo. No. 1, Electric Rules and Regulations
1st Revised Sheet No. 62.15, canceling Original Sheet No. 62.15
1st Revised Sheet No. 62.16, canceling Original Sheet No. 62.16
1st Revised Sheet No. 62.17, canceling Original Sheet No. 62.17
1st Revised Sheet No. 62.18, canceling Original Sheet No. 62.18.

ATTACHMENT 2

REHEARING APPLICATION

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.	))))	Case No. ER-2012-0174
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.	))))	Case No. ER-2012-0175

APPLICATION FOR REHEARING AND/OR MOTION FOR CLARIFICATION OF KANSAS CITY POWER & LIGHT COMPANY AND KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations Company ("GMO") (collectively the "Companies"), pursuant to Section 386.500.[1] and 4 CSR 240-2.160, apply for rehearing and move for clarification of the Commission's Report and Order ("Report and Order") issued January 9, 2012. In support of this Application and Motion, the Companies state as follows:

I. Legal Principles that Govern Applications for Rehearing.

1. All decisions of the Commission must be lawful, with statutory authority to support its actions, as well as reasonable. State ex rel. Ag Processing, Inc. v. PSC, 120 S.W.3d 732, 734-35 (Mo. banc 2003). An order's reasonableness depends on whether it is supported by substantial and competent evidence on the record as a whole. State ex rel. Alma Tel. Co. v. PSC, 40 S.W.3d 381, 387 (Mo. App. W.D. 2001). An order must not be arbitrary, capricious, or unreasonable, and the Commission must not abuse its discretion. Id.

2. In a contested case, the Commission is required to make findings of fact and conclusions of law pursuant to Section 536.090. Deaconess Manor v. PSC, 994 S.W.2d 602, 612 (Mo. App. W.D. 1999). For judicial review to have any meaning, it is a minimum requirement

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[1] All references are to the Missouri Revised Statutes (2000), as amended.

that the evidence, along with the explanation thereof by the Commission, make sense to the reviewing court. State ex rel. Capital Cities Water Co. v. PSC, 850 S.W.2d 903, 914 (Mo. App. W.D. 1993). In order for a Commission decision to be lawful, the Commission must include appropriate findings of fact and conclusions of law that are sufficient to permit a reviewing court to determine if it is based upon competent and substantial evidence. State ex rel. Monsanto Co. v. PSC, 716 S.W.2d 791, 795 (Mo. banc 1986); State ex rel. Noranda Aluminum, Inc. v. PSC, 24 S.W.3d 243, 246 (Mo. App. W.D. 2000); State ex rel. A.P. Green Refractories v. PSC, 752 S.W.2d 835, 838 (Mo. App. W.D. 1988); State ex rel. Fischer v. PSC, 645 S.W.2d 39, 42-43 (Mo. App. W.D. 1982), cert. denied, 464 U.S. 819 (1983).

3. In State ex rel. GS Technologies Operating Co. v. PSC, 116 S.W.3d 680, 691-92 (Mo. App. W.D. 2003), the Court of Appeals described the requirements for adequate findings of fact when it stated:

> While the Commission does not need to address all of the evidence presented, the reviewing court must not be "left 'to speculate as to what part of the evidence the court found true or was rejected.'" … In particular, the findings of fact must be sufficiently specific to perform the following functions:
>
> > [F]indings of fact must constitute a factual resolution of the matters in contest before the commission; must advise the parties and the circuit court of the factual basis upon which the commission reached its conclusion and order; must provide a basis for the circuit court to perform its limited function in reviewing administrative agency decisions; [and] must show how the controlling issues have been decided[.]
>
> [St. Louis County v. State Tax Comm'n, 515 S.W.2d 446, 448 (Mo. 1974), citing Iron County v. State Tax Comm'n, 480 S.W.2d 65 (Mo. 1972)].

4. The Commission cannot simply recite facts on which it bases a "conclusory finding," and must rather "fulfill its duty of crafting findings of fact which set out the basic facts from which it reached its ultimate conclusion" in a contested case. Noranda, 24 S.W.3d at 246.

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"Findings of fact that are completely conclusory, providing no insights into how controlling issues were resolved are inadequate." Monsanto, 716 S.W.2d at 795.

5. A review of the evidentiary record in this case demonstrates that the Report and Order failed to comply with these principles in certain respects and that rehearing should be granted as to the issues discussed below.

II. **Issues on Which Rehearing and/or Clarification is Sought.**

A. **Return on Equity.**

6. The Report and Order failed to abide by these standards when it set the Companies' return on common equity ("ROE") at 9.7%. The Commission provided no justification for setting the ROE well below the national average of ROEs ordered by other state utility commissions, and ignored the submissions provided by the Companies demonstrating that ROEs set or authorized by utility commissions from California to South Carolina were higher than the 9.70% ROE set in this case.

7. The Commission's Findings of Fact are inadequate. They consist of only 14 paragraphs covering slightly more than three pages. Although they purport to be factual findings, they are grossly inadequate in that they fail to cite even one piece of evidence to support any of the 14 paragraphs. There are no citations to the record. There are no citations to exhibits admitted into evidence. The Report and Order stands in stark contrast to orders issued in other major cases by the Commission. See, e.g., Report and Order, In re Union Elec. Co., ER-2012-0166 (Dec. 12, 2012); Report and Order, In re Kansas City Power & Light Co., No. ER-2010-0355 (Apr. 12, 2011); Report and Order, In re Joint Application of Great Plains Energy Inc., Kansas City Power & Light Co. and Aquila, Inc., No. EM-2007-0374 (July 1, 2008); Report and Order, In re Kansas City Power & Light Co., No. ER-2007-0291 (Dec. 6, 2007).

8. Consequently, the Commission Report and Order has "made no basic findings from the evidence adduced at the hearing," and must be set aside as inadequate. St. Louis County Water Co. v. State Highway Comm'n, 386 S.W.2d 119, 124 (Mo. 1964). See AT&T Communications of the Southwest, Inc. v. PSC, 62 S.W.3d, 545, 548 (Mo. App. W.D. 2001); State ex rel. Noranda Aluminum, Inc. v. PSC, 24 S.W.3d 243, 246 (Mo. App. W.D. 2000).

9. Anyone who reviews the Commission's Report and Order is either compelled to take each and every finding of fact at face value and assume that some place in the record there is evidence to support it, or is left to speculate what witness or what piece of documentary evidence supports the finding. This is insufficient as a matter of law. As the Court of Appeals has declared: "The only means by which we could review the Commission's conclusion would be to comb through the record looking for evidence that supported it and presuppose that the Commission accepted this evidence as true. This is unacceptable." State ex rel. Noranda Aluminum, Inc. v. PSC, 24 S.W.3d at 246.

10. Even if one were "to comb through the record" to look for supporting evidence, the effort would prove fruitless. For example, in Finding of Fact 11 the Commission concluded that the average ROE for the first nine months of 2012 was 9.97. See Report and Order ¶11 at 18. There is nothing to support that finding.

11. To the contrary, the record shows that the only evidence regarding the national averages of other state commission ROE awards for the first nine months of 2012 is 10.22%. See Hadaway GMO Surrebuttal Testimony, Sch. SCH-14 at 5. Moreover, the Third Quarter 2012 average ROE for vertically-integrated electric utilities like the Companies was 9.90%, with the last four quarters reported there averaging 10.14%. Id.

12. The Commission also made findings of what the "best projections of nominal GDPs [Gross Domestic Product] are," setting forth percentages for the years 2012 (3.9%), 2013

(4.1%), 2014-15 (5.1%), and 2018-23 (4.7%) in Finding of Fact 12. It cites no evidentiary source in the record for these findings.

13. A review of the record does not reveal where the Commission found these numbers in the record. Staff's analysis, which was ultimately rejected by the Commission, "found a relatively wide dispersion in projected EPS [Earnings Per Share] growth" of 3.0% to 8.0%, and ultimately settled on a growth rate range of 5.0% to 5.5%. See Staff KCP&L Ex. 202, Staff Cost of Service Report at 40-41. Mr. Kahal, the expert of the Federal Executive Agencies (FEA), used a growth rate range of 4.5% to 5.5%. See USDOE Ex. 550, Kahal Direct at 23. Public Counsel's expert Mr. Gorman used a growth rate of 5.14% for his Constant Growth DCF model, 4.85% for his Sustainable Growth DCF model, and a long-term growth rate of 4.9% for the final stage of his Multi-Stage Growth DCF model. See OPC Ex. 300, Gorman Direct at 19, 21, 25. None of these figures supports the findings made by the Commission which are apparently based on sources not in the record.

14. The Commission explicitly rejected the 5.7% growth rate recommended by the Companies' expert Dr. Hadaway. In rejecting that figure, the Commission committed error by failing to accurately describe how it was calculated. Although the findings supplied on this issue by the Commission are located in the Conclusions of Law section of the Report and Order on page 21, they are actually phrased as factual findings, not legal conclusions, and are in error.

15. The Commission found that the Companies "use a 5.7% GDP projected from 1971-1980 data, which is not helpful to the 30 most recent lower growth years, and does not reflect investor expectations." See Report and Order at 21. However, this is an erroneous finding because the record is clear that Dr. Hadaway did *not* recommend a 5.7% growth rate based solely on 1971-80 data.

16. To the contrary, Dr. Hadaway explained both in his pre-filed testimony, as well as in live testimony at the evidentiary hearing that the 5.7% growth rate recommendation was based upon 60 years of data ranging from 1951 through 2011. See KCPL-20, Hadaway Rebuttal at 13, 23 & Sch. SCH-11. Contrary to the Commission's findings, Dr. Hadaway gave greater weight to more recent years, especially the past decade, as opposed to the 1970s, which the Commission mistakenly concluded he did. Dr. Hadaway testified:

> However, to account for recent data having a greater influence on current expectations, I applied a weighted averaging process that gives about five times as much weight to the most recent 10 years as compared to the earliest 10 years. Giving more weight to the more recent, low inflation years also lowers the overall forecast. [Id. at 23.]

17. Dr. Hadaway concluded that his updated forecast for a future growth rate of 5.7% was lower than the overall long-run average of over 60 years of data (1951-2011), which yielded a growth rate of 6.6%. Id. The Commission's finding that Dr. Hadaway arrived at a projected 5.7% GDP growth rate "from 1971-1980 data" is clearly erroneous.

18. At the evidentiary hearing, under cross-examination Dr. Hadaway explained that the most recent ten-year average of growth rates, which reflects the most recent very low growth period, including negative growth rate in 2008 and zero growth in 2009, was "given six times as much weight" as the other ten-year averages which included periods of much higher growth rate. See Tr. 399. Consequently, the low growth rate for the most recent ten-year period (2000-2011) is in "every one of those averages, it's in there six times." Id. at 448.

19. The Commission's order is also unreasonable in that it ignored the Fourth Quarter 2012 ROEs approved by other state utility commissions around the United States. With the exception of Kansas, state utility commissions authorized ROEs from a low of 9.80% to 10.40% for vertically-integrated utilities. See Exhibit A, Regulatory Research Associates, Regulatory

Focus, "Major Rate Case Decisions -- Calendar 2012" (Jan. 17, 2013. The average ROE for vertically-integrated utilities was reported as 10.16% for the Fourth Quarter. Id.

20. With the upswing in the economy and improvement in growth, other state commissions recognized the positive news and took appropriate action in setting ROEs. Contrary to what the Commission apparently believes, the average ROE for all utilities *increased* from 9.78% (the Third Quarter 2012 figure quoted by the Commission at pages 18 and 23 of the Report and Order) to 10.05% in the Fourth Quarter. See Exhibit A. The Commission's ROE decision for the Companies is, therefore, 35 points below the national average.

21. For vertically-integrated utilities like the Companies, the average ROE also *increased*, from a Third Quarter average of 9.90% to a Fourth Quarter average of 10.16%. Id. The disparity here is even more glaring, with Commission's ROE decision being an unreasonable 46 points below the national average.

22. The Commission erroneously found that the adjustment made by Dr. Hadaway to the Companies' proxy group "omitted three of the companies with the lowest RoE …." See Report and Order at 20. The record shows that of the four companies removed by Dr. Hadaway in his second proxy group, only two had earnings growth estimates that were low (Edison International and Cleco).

23. Vectren and Ameren had relatively high earnings growth potential and were not among the three lowest ROE companies in the proxy group. Compare KCPL-19, Hadaway Direct, Sch. SCH-5 at 1 with KCPL-20, Hadaway Rebuttal, Sch. SCH-12 at 1. Low-ranking utilities like IDACORP (parent of Idaho Power Company) and Xcel Energy were not removed. Id. The Commission's finding that the changes Dr. Hadaway made to his proxy group caused a

"skewing" of "his results" -- that is, distorting them from their true value or slanting them[2] -- is not supported by the record. See Report and Order at 21, n. 51.

24. Despite these criticisms, the Commission uses Dr. Hadaway's ROE of 9.8% from his second proxy group Constant Growth DCF model to support its award of a 9.7% ROE. Id. at 21-22. However, it failed to note that Dr. Hadaway's other DCF recommendations from his second proxy group analysis yielded average and mean ROEs of 10.1% and 10.0%, respectively, under the Constant Growth DFC model using long-term GDP growth rates. See KCPL-20, Hadaway Rebuttal, Sch. SCH-12 at 1.[3]

25. Given the well-established requirement that the Commission should authorize a return on common equity that is commensurate with returns on other investments of corresponding risks, its decision to award a 9.7% ROE to the Companies is unjust, unreasonable, arbitrary, not supported by substantial and competent evidence of record, and not supported by adequate findings of fact and conclusions of law. See Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944); Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 670 (1923).

26. In order to put itself back in the mainstream of where the Companies' allowed return on common equity should be, the Commission must grant rehearing and authorize the Companies to earn an ROE of at least 9.8%. This figure falls within the ranges recommended both by Mr. Kahal, on behalf of the Federal Executive Agencies, and Dr. Hadaway on behalf of the Companies. See Report and Order at 19-20.

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[2] The Merriam-Webster Dictionary defines "skew" as "to distort especially from a true value or symmetrical form."

[3] Both the average and median Low Near-Term Growth DCF model (2-Stage growth) supported a 9.9% ROE. See KCPL Ex. 20, Hadaway Rebuttal, Sch. SCH-12 at 1.

B. <u>Transmission Tracker.</u>

27. It is clear from the Report and Order that the Commission wants the Companies to be able to defer or track transmission costs above those in base rates. The Commission believes that the Companies can already track transmission cost increases under the Uniform System of Accounts ("USoA"). <u>See</u> Report and Order at 29. Moreover, the Commission, in its Findings of Fact on this issue, accurately noted that the Southwest Power Pool's ("SPP") regional transmission upgrade projects and administrative fees represent an approximately 14% increase per year and theses transmission costs will continue to increase at an accelerating pace. <u>See</u> Report and Order at 28-29. The Companies appreciate the Commission's analysis of this important issue but do not agree, as explained below, with the Commission's belief that it cannot grant "any practical relief" to the Companies regarding these accelerating costs. In order to effectuate its desire that the transmission costs be deferred under the USoA, the Commission must provide the essential language that the Companies need to defer these costs under the USoA. As explained below, the Commission must specifically find that the Companies are authorized by the Commission to record as a regulatory asset (Account 182.3) or regulatory liability (Account 254) the excess, or shortfall, amount of transmission expense compared to what is currently included in base rates, respectively, to be addressed in the Companies' next general rate proceeding.

28. The Companies move for clarification of that portion of the Report and Order concerning the Transmission Tracker, or alternatively, a rehearing on the grounds that the Report and Order is unlawful and unreasonable, and lacks sufficient findings of fact to support the Report and Order. <u>See</u> Report and Order at 28-32. In particular, the Report and Order is unreasonable and not based upon competent and substantial evidence in its finding

that "Applicants have not carried their burden of proving that the Commission should order deferred recording ("a tracker") for transmission costs. The issue is moot because Applicants can already determine how to record that costs by themselves, as they do with almost every cost every day, under the Uniform System of Accounts." See Report and Order at 28.

29. There is no competent and substantial evidence on the record that supports the finding and conclusion that the Companies' already have the authority under the USoA to determine how to record and defer the transmission costs by themselves if they are more than 5% of net income without a further order from the Commission. See Report and Order at 31-32. In fact, there is no testimony in the entire record in which any party proposed or suggested that the Companies already have the discretion to determine whether to defer transmission costs for review and possible recovery in the Companies' next rate cases without a specific order from the Commission. As a result, this portion of the Order is unlawful and unreasonable.

30. The Report and Order specifically finds that the Companies' request for a transmission tracker "is moot because the Commission can grant no practical relief. No practical relief is possible because Applicants can already 'track' transmission cost increases under the plain language of the only authority that any party cites for a tracker." See Report and Order at 29. The Report and Order goes on to interpret the USoA as indicating that no Commission order is needed to defer the transmission costs, assuming they are more than 5% of income, when it states: "If the projected transmission increases prove to be more than five percent of income, they will be subject to deferral without the Commission's order." See Report and Order at 32.

31. In interpreting the USoA, the Commission erroneously links General Instruction No. 7[4] with the appropriate USoA authority cited for establishment of regulatory assets and regulatory liabilities, the account definitions of accounts 182.3 and 254, respectively, which are provided in the USoA and provided in Appendix C to the Commission's Report and Order. The Commission errs when it states at page 29 of the Report and Order that "Whether a utility may defer an item is the subject of General Instruction No. 7." This statement is inconsistent with the USoA. The correct application of General Instruction No. 7 is that it provides for relocation on a Company's income statement of items considered extraordinary. Nowhere in General Instruction No. 7 does it provide for the deferral of income statement activity to the Balance Sheet. Deferral to the Balance Sheet is addressed only, and appropriately, in the USoA under the descriptions of Accounts 182.3 and 254. The USoA does not link General Instruction No. 7 and the descriptions of Accounts 182.3 and 254. Because of its inaccurate linkage of these sections of the USoA, the Commission errs in deciding that "If the projected transmission increases prove to be more than five percent of income, they will be subject to deferral without the Commission's order."

32. The Commission errs in determining that General Instruction No. 7 provides that a Commission order is only necessary for an item that is less than 5% of income because it misapplies General Instruction No. 7 of the USoA. See Report and Order at 29-30. The correct application of General Instruction No. 7 is that a Company may reflect items meeting the criteria of General Instruction No. 7 and which are greater than 5% of net income in the extraordinary item section of their income statement, specifically to Accounts 434 and 435. Thus, General

[4] The Companies are not aware that General Instruction No. 7 was introduced into the record of this proceeding. There is no competent and substantial evidence to support the Commission's reliance upon General Instruction No. 7. As explained herein, the Commission has misinterpreted the application of General Instruction No. 7, and the Commission should grant rehearing on this aspect of the Report and Order.

Instruction No. 7 only addresses the appropriate income statement classification of extraordinary items. The restriction in General Instruction No. 7 that Commission approval must be obtained to treat an item of less than 5% as extraordinary is equally misinterpreted by the Commission. This restriction does not suggest that state regulatory Commission approval is appropriate. Rather, it requires Companies to obtain <u>FERC Commission</u> approval before classifying an item of less than 5%, as an extraordinary <u>income statement</u> classification change and reflect the item in Accounts 434 and 435.

33. Historically, public utilities have sought prior approval from the Commission to establish various trackers or accounting authority orders. This is the case because General Instruction No. 7 of the USoA is not authoritative to deferral of charges that would normally be recorded in expense under the USoA, as erroneously asserted by the Commission. Accounts 182.3 and 254 are the only authority under the USoA to record the deferrals. The plain language of the definition of Account 182.3 in the USoA and provided in Appendix C of the Report and Order is crystal clear on what is necessary to defer amounts to Account 182.3:

> This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies.

34. It is notable that for Accounts 182.3 and 254, there is no reference to General Instruction No. 7 and there is no reference to any such 5% threshold. That is because neither General Instruction No. 7 nor the 5% threshold apply to deferral to Accounts 182.3 and 254. The one and only criteria for deferral to Accounts 182.3 and 254 is that deferrals result from the ratemaking actions of regulatory agencies. This is precisely why, historically, public utilities have sought prior approval from the Commission to establish various trackers or accounting authority orders and why, in this case, the Companies initially

sought approval of an Accounting Authority Order ("AAO") related to the recent Missouri River flood, as well as a Renewable Energy Standards Tracker and Property Tax Tracker in addition to the Transmission Expense Tracker. See KCPL-29, Ives Direct at 12-21; GMO-123, Ives Direct at 11-20. See also Re Kansas City Power & Light Company, Case No. EU-2012-0130 (AAO related to interruptions coal supplied to some of its power plants caused by the 2011 Missouri River flooding); Re Union Electric Company, File No. EU-2012-0027; Re Empire District Electric Company, File No.EU-2011-0387; Re Union Electric Company, Case No. EU-2008-0141; Re Aquila, Inc., Case No. EU-2008-0233; Re Kansas City Power & Light Company, Case No. EU-2006-0560.

35. Although, as noted above, the Commission has misinterpreted and misapplied General Instruction No. 7 and the guidance provided in the USoA for Accounts 182.3 and 254, the Companies believe that the Commission understood that the Companies have the ability to defer transmission costs under the USoA and is authorizing in its Report and Order the Companies to defer transmission costs to a regulatory asset for deferral and determination of recovery in a future rate case. Under the appropriate application of the USoA for Accounts 182.3 and 254 though, the Companies require evidence of ratemaking actions of regulatory agencies to be able to record the deferrals intended by the Commission in its Report and Order. **Therefore, the Companies hereby seek clarification of this portion of the Report and Order, and request that the Commission specifically find that the Companies are authorized by the Commission to record as a regulatory asset (Account 182.3) or regulatory liability (Account 254) the excess, or shortfall, amount of transmission expense compared to what is currently included in base rates, respectively, to be addressed in the Companies' next general rate proceeding.**

36. The Companies believe that this finding and conclusion by the Commission will be essential for the Companies' outside external auditors to permit the Companies to defer such excess, or shortfall, in transmission costs to a regulatory asset or liability, respectively. Otherwise, the Companies will not have the discretion to defer such costs to a regulatory asset or liability without a Commission order. This result would be inconsistent and contrary to the apparent intent of the Report and Order to give the Companies the discretion to book and defer such transmission expenses to a regulatory asset or liability, and allow the Commission to consider recovery of these transmission expenses in a future rate proceeding.

37. In the alternative, the Companies seek rehearing of the Commission's decision to deny a transmission tracker. For all of the reasons stated in the Companies' testimony, a transmission tracker is an appropriate regulatory tool and would promote the public interest. The Companies request a rehearing on this issue and request that the Commission authorize the use of a transmission tracker mechanism to ensure appropriate recovery of transmission costs as a result of charges from SPP and other providers of transmission service.

38. The record demonstrates that these actual charges from transmission providers are appropriate candidates for a tracker mechanism because they are material, expected to change significantly in the near future, and are primarily outside the control of KCP&L and GMO. Transmission costs can change significantly from year-to-year, and such costs are a material cost of service component. Historically, transmission costs have fluctuated due to load variations, both native and off-system. However, the Companies are currently experiencing increasing costs for SPP's regional transmission upgrade projects and

increasing SPP administrative fees. The Companies expect these costs to continue to increase. See KCPL-29, Ives Direct at 13-17; GMO-123, Ives Direct at 11-15.

39. The Companies should be authorized to use a transmission expense tracker due to the historical growth in and current high level of the Companies' transmission expenses, the uncertainty in the levels of its future transmission expenses, and because the Companies have less control over the level of transmission expenses the SPP assigns to it than the Company has over most of its other expenses. The Commission's Order related to the denial of the Transmission Tracker is neither lawful nor supported by competent and substantial evidence. In addition, the Commission's Order does not include appropriate findings of fact and conclusions of law that are sufficient to permit a reviewing court to determine if it is based upon competent and substantial evidence. For these reasons, the Companies request a rehearing on the transmission tracker issue if the Commission does not clarify its order, as requested herein.

40. Typically, trackers have been utilized for expenses that are material, expected to change significantly in the near future, and are primarily outside the control of the public utility. Many varied trackers have been established over the years (e.g. pension, Iatan O&Ms, Off-system Sales, vegetation management expense, storm trackers, etc.). AAOs have been utilized to capture costs associated with extraordinary occurrences, but not necessarily related to specific environmental events such as an ice storm, tornado, or flood. Some examples of the different AAOs given to utilities over the years have included ice storms (Nos. EU-2002-1053 and EU-2008-0233), environmental work at power plants (Nos. EO-90-114 and EO-91-38), and additional expenses for special projects (No.EO-91-247). However, from a practical standpoint, both trackers and AAOs have the effect of giving the utility the ability to defer expenses from the current period to a future period with a determination of recovery in a future rate case. The

Companies request that the Commission either clarify its order and specifically find that the Companies are authorized by the Commission to record as a regulatory asset (Account 182.3) or regulatory liability (Account 254) the excess, or shortfall, amount of transmission expense compared to what is currently included in base rates, respectively, to be addressed in the Companies' next general rate proceedings, or alternatively grant a rehearing on the Transmission Tracker issue.

C. Winter, Space Heat, and All-Electric Issue.

41. The Companies also seek rehearing of a portion of the Commission's Report and Order related to the Winter, Space Heat, and All-Electric issue. See Report and Order at 33-40, as modified, Order of Clarification (Jan. 11, 2013).

42. On January 11, 2013, Staff filed its Motion For Clarification in which it announced that since the Commission varied from the terms of the Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design, "Staff reverted to its initial position of recommending increases to the first block of the KCPL winter all electric LGS rate schedule." See Staff Motion at 2. In its Motion, "Staff seeks clarification that the Commission intended to order, and did order (1) Staff's recommended increases to the first block of the KCPL winter all electric SGS and MGS rate schedules, and (2) Staff's recommended increase to the first block of the KCPL winter all electric LGS schedule." Id.

43. On January 11, 2013, the Commission issued its Order of Clarification which stated at page 3:

> Staff's motion asks the Commission to rule on Staff's proposal to increase certain rates. The part at issue addresses the winter first energy block of the all-electric rate schedules for Small General Service ("SGS"), Medium General Service ("MGS"), and Large General Service ("LGS"). No ruling on that proposal appears in the Report and Order. In its brief, Staff sought a ruling on SGS and MGS, and referred to the rate design statement on LGS. But in Staff's motion, Staff correctly notes that the rate design statement is not binding, so Staff refers to its earlier

> position on LGS. The Commission intended to grant that proposal on page 39 of the Report and Order. The discussion on that page shows where it addressed the RESB and RESC shows that to be true. Therefore the Commission corrects the Report and Order nunc pro tunc.

44. For the reasons stated herein, the Companies seek rehearing on the decision to adopt Staff's motion and Staff's rate design proposal as it relates to the winter first energy block of the all-electric rate schedules for Small General Service ("SGS"), Medium General Service ("MGS"), and Large General Service ("LGS"). Staff's motion for clarification should have been denied. Instead, the Commission should have held that the rate increases for the SGS, MGS, and LGS classes should be spread on an equal percentage basis, as recommended by KCP&L's testimony. See KCPL-41, Rush Direct at 9; KCPL-42, Rush Rebuttal at 5; KCPL-43, Rush Surrebuttal at 6-10).

45. This position was also embodied in the recommendations contained in the Non-Unanimous Stipulation and Agreement Regarding Class Cost of Service / Rate Design at page 2: "The overall increase granted by the commission should be applied as an equal percentage increase to the base rate revenues of each class after adjusting to the inter-class adjustments described in paragraph 1."

46. As explained by KCP&L witness Tim M. Rush, if major changes in rate design occur, then there is a likelihood that customers will switch between classes, and this "rate switching" phenomena can affect the Company's ability to recover its revenue requirement. See KCPL-42, Rush Rebuttal at 5. As Mr. Rush testified: "Any significant change to the Small, Medium, Large, and Large Power classes will put the company at risk to rate switching." Id. at 5. In his Surrebuttal Testimony, Mr. Rush explained this problem as follows:

> Staff's proposal does not explore the disruption of the relationship between the Large General Service and the Large Power rate groups, leading to the potential rate switching impact of its proposal. Mr. Scheperle does not address my concern in his Rebuttal. In fact, in response to the Industrials' proposal, on page 19 of Mr.

> Scheperle's Rebuttal, he expresses the exact, rate switching concern I offer in respect to the Staff proposal. Rate switching is a very real risk to the Company and its ability to realize the authorized rate increase amount. [KCPL-43, Rush Surrebuttal at 9].

47. The Company's testimony regarding the "rate switching" phenomena was not refuted by any party in this proceeding, including Staff. However, it was not addressed by the Report and Order or the Order Of Clarification, and the Commission's decision fails to consider this important concern that will result from the adoption of the Staff's proposal to increase the first winter energy block of the all-electric rate schedules from SGS, MGS, and LGS. Consequently, the Report and Order is not based on competent and substantial evidence, makes inadequate findings of fact, and is unreasonable. The Commission should therefore grant rehearing on this portion of the rate design issue.

D. Revenue Shift Among Rate Schedules.

48. The Companies request that the Commission rehear and reconsider the following conclusion found on page 38 of the Report and Order:

> The Commission concludes that the shifts that OPC proposes for KCPL best furthers the policy of moving rates toward recovery. That is because it represents a middle ground between the undesirable results of the status quo (leaving disparities in recovery unaltered) and eliminating all disparities immediately (causing rate shock). The Commission concludes that OPC's proposal will best support safe and adequate service at just and reasonable rates, so the Commission will order the shifts that OPC proposes for KCPL.

49. KCP&L requests a rehearing related to the adoption of OPC's proposal to make revenue shifts among the rate schedules, as this conclusion is not based upon competent and substantial evidence and is an abuse of the Commission's discretion. The competent and substantial evidence on record as a whole supported the proposal of the Company, Staff, and other signatories to the KCP&L Class Cost of Service Stipulation and Agreement ("KCP&L CCOS Stipulation") to increase residential rates slightly more than other rate schedules.

50. The signatories to the KCP&L CCOS Stipulation agreed that the Commission should increase residential true-up revenues by 1.00% in addition to any other increase implemented by the Commission with a corresponding equal-percentage revenue neutral decrease in the true-up revenues for all other non-lighting rate classes. This shift is consistent with the CCOS studies which demonstrated that the residential class was not paying its appropriate share of the Company's costs of service. See KCPL-38, Normand Direct, Sch. PMN-2; Staff-211 Staff Rate Design and Class Cost of Service Report at 3; USDOE-501, Goins Direct, Sch. DWG-1. In fact, all of the class cost of service studies in the record showed that residential rates as a whole were not recovering their cost of service. However, the Commission ignored or disregarded this competent and substantial evidence when it granted OPC's proposed revenue shift among the various rate schedules. The Commission should therefore grant rehearing of this issue. Id.

51. By adopting the OPC's position regarding revenue shifts among the classes, the Company is concerned that there will be "rate switching" by various customers. As explained by Mr. Rush in his Rebuttal Testimony, "Any significant change to the Small, Medium, Large, and Large Power classes will put the company at risk to rate switching . . . [I]f major shifts between classes occurred, it would be necessary to take rate switching into account as part of the final rate design definition." See KCPL-42, Rush Rebuttal at 5.[5] The Commission's Report and Order

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[5] Rate switching concerns have also been addressed in rate design stipulations and agreements in previous KCP&L rate cases. See e.g., Non-Unanimous Stipulation And Agreement As To Class CCOS and Rate Design, Case No. ER-2010-0355, paragraph 5, p. 2:

> 5. Any potential revenue shortfall associated with potential migration of customers resulting from the LGS / LP rate design methodology provided in paragraph 4, currently quantified as $395,000 shall be assigned to the LGS and LP classes on the basis of relative energy usage by those classes) i.e.) based on the LGS class allocator being (annual LGS class kWh usage) I (annual LGS class kWh usage + annual LP class kWh usage); and the LP class allocator being: (annual LP class kWh usage) I (annual LGS class kWh usage + annual LP class kWh usage), using trued-up amounts for the annual class kWh usages of the LGS and LP classes.

adopted OPC's proposed revenue shifts, but it failed to take into account the rate switching that will occur. Therefore, the Commission should grant a rehearing on this issue.

E. Crossroads Energy Center.

a. The Commission's Decisions Regarding the Valuation of Crossroads and the Disallowance of Crossroads Transmission Costs Are Not Based Upon Appropriate Findings of Fact and Conclusions of Law.

52. The Commission's Report and Order failed to make sufficient findings of fact and conclusions of law related to the valuation of the Crossroads Energy Center ("Crossroads") as well as to the disallowance of transmission costs associated with the delivery of power from Crossroads. Very little of what the Commission said in its Report and Order on these issues actually constituted findings of fact or conclusions of law.

53. Other than its Accumulated Deferred Income Tax ("ADIT") calculation, the Commission arrived at the same erroneous Crossroads conclusions as it did in GMO's last rate case, No. ER-2010-0356 (which the Commission referred to as the "previous rulings"). Although the Commission did correct the ADIT errors from that case and properly calculated the ADIT associated with Crossroads based upon the regulatory value that it found, the Commission failed to change its previous rulings on Crossroads' valuation and electric transmission costs.

54. In so doing, the Commission "incorporates, as if fully set forth its findings of fact and conclusions of law from the previous rulings and recapitulates only the most salient facts relevant to Crossroads' valuation only as necessary to show how the movants for change have failed to meet their burden of proof." See Report and Order at 52. However, no party incorporated the evidence from the last case into this case, nor did any party present evidence on which the Commission could decide *in this case* that the value of Crossroads is something other than the Company's proposed net original cost. Consequently, it is not surprising that the

Commission rejects GMO's positions on valuation and transmission costs in only eight pages which contain no citations to the record.

55. Because the Commission's factual findings and conclusions of law on the Crossroads issues fail to cite even one piece of evidence, they are clearly inadequate. St. Louis County Water Co. v. State Highway Comm'n, 386 S.W.2d 119, 124 (Mo. 1964). Furthermore, because the Commission merely relied upon its previous rulings, it clearly did not consider additional evidence presented only in this case. As such, its Report and Order is not based on competent and substantial evidence on the record as a whole.

56. As the previous rulings on valuation and transmission costs were unlawful and unreasonable for the reasons GMO stated in its May 13, 2011 Motion for Clarification and/or Reconsideration and Application for Rehearing in its last rate case, No. ER-2010-0356, so too are the Commission's present rulings unlawful and unreasonable. Rehearing thus should be granted as to the valuation and disallowance of transmission costs from Crossroads, discussed below.

b. The Commission's Valuation Is Unreasonable and Contrary to the Record.

57. The Commission determined that the fair market value of Crossroads as of August 31, 2012 is $62.6 million. See Report and Order ¶ 7 at 55, 57. In making that determination, the Commission rejected GMO's inclusion of Crossroads in rate base at its "net original cost" as defined by the USoA. However, the Commission failed to analyze, and did not consider, GMO testimony regarding its valuation disclosure to the Securities and Exchange Commission ("SEC") and regarding the independent third-party appraisal of Crossroads. Furthermore, the Commission's use of the Goose Creek and Raccoon Creek units in making its valuation determination is not appropriate because those units and the circumstances surrounding their sale are not comparable to Crossroads. Indeed, the Missouri Court of Appeals, as well as the

Commission itself, have previously found that "their purchase price is not a good measure of the market price" for other units. State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 579 (Mo. App. W.D. 2009), quoting In re Union Elec. Co., Case No. ER-2007-0002, Report and Order at 62 (May 22, 2007) ("AmerenUE Report and Order"). As a result, the Report and Order is unreasonable, arbitrary, capricious, and not supported by adequate findings of fact and conclusions of law.

(i) The Commission Unreasonably Rejected GMO's Valuation Evidence.

58. Contrary to the Report and Order's statement at 55-56 that GMO relied on a valuation that pre-dates the Commission's adoption of FERC's USoA, the Company included Crossroads at its net book value, or its "net original cost" as defined by the USoA. See GMO-125, Ives Surrebuttal at 26. As of March 31, 2012, GMO valued Crossroads at approximately $82.7 million. See GMO-111, Crawford Rebuttal at 1. No party rebutted the Company's testimony that net original cost has been calculated using generally accepted accounting principles. See GMO-125, Ives Surrebuttal at 26. Nor did any party dispute the fair market valuation that the independent, third-party accounting firm PricewaterhouseCoopers determined was actually higher than the net original cost used by the Company in its filing in this case. See Tr. 937; GMO-111, Crawford Rebuttal at 2; GMO-125, Ives Surrebuttal at 37.

59. The evidence is undisputed that GMO transferred Crossroads to its regulated books at the fair market value of $117 million, as the fair market value of Crossroads was less than the fully distributed cost described in the Rebuttal Testimony of Mr. Crawford. See GMO-111, Crawford Rebuttal at 5, 7. GMO has routinely sought to include Crossroads in its rate cases at this fair market value (less depreciation in the present case). See GMO-111, Crawford Rebuttal at 1-5, 7, Sch. BLC2010-9(HC); GMO-125, Ives Surrebuttal at 29-30. GMO's

valuation evidence thus is consistent with the USoA. Finding otherwise is contrary to the substantial and competent evidence on the record. Consequently, the Report and Order is unreasonable, arbitrary, capricious, and not supported by adequate findings of fact and conclusions of law.

60. Furthermore, the Commission entirely disregarded the valuation of Crossroads at the time it was offered in response to the March 2007 Request For Proposals ("RFP") for supply resources put out by GMO. See GMO-111, Crawford Rebuttal at 3. There is no dispute in this case that Aquila's regulated operations acquired Crossroads from Aquila Merchant using an RFP process. See Tr. 913-914; Staff-271, Featherstone Rebuttal at 22; GMO-125, Ives Surrebuttal at 29. Crossroads was offered at its net book value, but also included projected transmission costs of $11 million. See Tr. at 913-14. Even with the $11 million in included transmission costs, which is more than double the actual transmission costs (id.), Crossroads was the lowest cost of several options considered. See GMO-111, Crawford Rebuttal at 3; Sch. BLC2010-9(HC); Tr. 913. Therefore, the Affiliate Transactions Rule, 4 CSR 240-20.015(3), dictates that the fair value of Crossroads at the time was the net book value, or its "net original cost" as defined by the USoA. This is exactly the basis for the value the Company requests in this rate case (less depreciation since that time).

61. The net original cost and the RFP response are the only evidence of what a willing buyer would pay a willing seller for the Crossroads facility. The Commission disregards this competent and substantial evidence on the record as a whole in following its previous unreasonable valuation methodology adopted in GMO's last rate case.

(ii) The Commission Unreasonably Relied on Statements to the SEC.

62. The Commission also makes much of Great Plains Energy Incorporated's ("GPE") preliminary, unilateral valuation filed in its S-4 Joint Proxy Statement[6] with the SEC regarding the "fair value" of Crossroads, yet completely disregards GMO's evidence as to why its valuation of the facility is higher than the preliminary salvage value included in the Joint Proxy Statement. See Report and Order ¶ 4 at 54-55.

63. The Joint Proxy Statement is not relevant to the valuation analysis. The evidence was undisputed that the Joint Proxy Statement value was preliminary and was not an agreement between a buyer and seller about the value. See GMO-125, Ives Surrebuttal at 31-38. While Staff provided a good deal of testimony about the Joint Proxy Statement, Staff never asserted that the preliminary proxy value was the correct value. See Tr. 943.

64. The text of the Joint Proxy Statement noted the preliminary and unilateral nature of the value stated. It clearly referred to GPE's "estimates" and disclosed that the value was a "preliminary internal analysis" that was "significantly affected by assumptions regarding the current market." See Staff-258, Cost of Service Report at 78-79.

65. Furthermore, while GPE disclosed to the SEC that the fair market salvage value of the combustion turbines alone was $51.6 million, it reported the net book value of the entire facility at $118.9 million. Id. at 78. Reading the Joint Proxy Statement in its entirety, it is clear that the $51.6 million allocation was preliminary, subject to change, could differ materially from the final purchase price allocation on the date the merger is completed, and did not represent the net book value of the entire facility.

[6] Form S-4, referred to as a joint proxy statement/prospectus, must be submitted to the SEC in the event of a merger or an acquisition between two companies. GPE and Aquila filed their Form S-4 with the SEC on May 8, 2007. It will be referred to as the "Joint Proxy Statement" herein.

66. Yet the Commission relied on these salvage value statements in determining that the sale of two "comparable assets" in Illinois supports its valuation. See Report and Order ¶ 4 at 55. Because the Commission failed to analyze and rejected the Company's evidence that GPE's preliminary statements to the SEC were not probative on the valuation issue, and instead relied upon these statements, its valuation of Crossroads is unreasonable, arbitrary, capricious, and not supported by adequate findings of fact and conclusions of law.

(iii) The Commission Unreasonably Calculated Valuation Using the "Forced Sale" of Two Dissimilar Combustion Turbines.

67. The "comparable assets" upon which the Commission calculated the Crossroads value are the Goose Creek and Raccoon Creek combustion turbines in Illinois. See Report and Order ¶ 5 at 55. "Using the same valuation as in the previous rulings," the Commission calculated the value of Crossroads using the average installed dollar per kilowatt basis that AmerenUE,[7] another public utility, paid for those combustion turbines. See Report and Order 52, ¶ 7 at 55.

68. In its previous rulings adopted here, the Commission determined that Goose Creek and Raccoon Creek transactions were a "good indicator of the fair market value" and showed "the depressed market" for gas turbines at that time, without any evidence that the different years and different location in which those transactions occurred are sufficiently similar to warrant their comparison. See Case No. ER-2010-0356 Report and Order ¶ 270 at 94, ¶ 275 at 96.

69. However, the Goose Creek and Raccoon Creek transaction was "essentially a forced sale." State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 579 (Mo. App. W.D. 2009).

[7] AmerenUE, now doing business under the name Ameren Missouri, is Union Electric Company, a regulated Missouri public utility. See State ex rel. Public Counsel v. PSC, 274 S.W.3d 569, 572 & n.1 (Mo. App. W.D. 2009).

Because of the circumstances surrounding their sale, "their purchase price is not a good measure of the market price" for other units. Id., quoting AmerenUE Report and Order at 62. Nevertheless, the Commission now unreasonably and arbitrarily relies on the average installed dollar per kilowatt basis that AmerenUE paid for those units in arriving at its valuation for Crossroads.

70. Such reliance is further unreasonable, as the record demonstrates that Goose Creek and Raccoon Creek are not "comparable assets" because the cost to operate the facilities in the provision of retail electric service to GMO customers would be markedly different.[8] GMO, unlike AmerenUE, would need annual revenue of $9.7 million to transmit the electricity if it were to purchase those facilities, which is nearly double the $5.2 million revenue requirement to transmit power from Crossroads. See GMO-111, Crawford Rebuttal at 7. Similarly, gas transportation is significantly higher for those facilities. See GMO-103, Blunk Rebuttal at 3; GMO-111, Crawford Rebuttal at 7. This analysis makes clear that, for GMO, Crossroads was the lowest cost option. See GMO-111, Crawford Rebuttal at 7.

71. Contrary to the substantial and competent evidence on the record, and diverging from the findings by the Court of Appeals, the Commission calculated the value of Crossroads using the average installed dollar per kilowatt basis that AmerenUE paid for Goose Creek and Raccoon Creek. As a result, the Report and Order is unreasonable, arbitrary, capricious, and not supported by adequate findings of fact and conclusions of law.

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[8] Even Staff concedes that "there is a material difference in the comparison of GMO's acquisition of Crossroads with AmerenUE's acquisition of Goose Creek and Raccoon Creek." See Staff Initial Brief at 54.

c. The Commission Unreasonably and Unlawfully Disallows Crossroads Transmission Costs.

72. In a brief two-page discussion, the Commission denied GMO cost recovery for transmitting power from Crossroads to its MPS rate district. See Report and Order at 59. In making that determination, the Commission failed to make appropriate findings of fact and conclusions of law, failed to analyze and consider GMO's evidence regarding its least cost analysis of Crossroads, and unreasonably removed from the lowest-cost Crossroads option the one element of cost that was higher than its other elements.

73. The section of the Report and Order entitled "Transmission Cost" set forth at pages 58-59 does not include appropriate findings of fact and citations to the record, and thus failed to meet the statutory requirements of Sections 386.420 and 536.090. See Noranda, 24 S.W.3d at 243. The Commission's statements were completely conclusory, and provided no reasonable explanation for why the transmission costs were disallowed from recovery when the Crossroads plant itself was found to be prudent and was included in rate base.

74. Furthermore, the Commission's decision to eliminate the transmission cost component from retail rates is unlawful. In excluding from rates the cost of transmission required to bring energy from Crossroads to GMO's service territory, the Commission improperly ordered the elimination of the tariff rate approved by FERC, thus "trapping" such costs in violation of the Filed Rate Doctrine and the Supremacy Clause of the U.S. Constitution.

(i) The Commission Failed to Analyze the Undisputed Evidence that the Cost of Transmission is Outweighed By Savings in Fuel Costs.

75. The Commission disregarded the evidence of transmission costs as part of the overall cost analysis of the Crossroads plant, contrary to its finding that it was the most prudent resource alternative. Furthermore, in simply adopting its findings in the previous rulings, the

Commission failed to consider new, additional evidence included in this case that was not part of GMO's last general rate case.

76. At hearing, Staff's witness acknowledged that a utility would be prudent to utilize a power plant outside of its service area if this presented the lowest cost to ratepayers. See Tr. 956-57. That is exactly why GMO chose the Crossroads option. Nevertheless, the Commission found that "[t]he high cost of transmission is not outweighed by lower fuel costs in Mississippi," and disallowed transmission costs. See Report and Order ¶ 3 at 58. This finding is contrary to the evidence.

77. It was undisputed that producing electricity through the use of natural gas is significantly less expensive in Mississippi because of its proximity to natural gas fields. See Tr. 316. As a result of this proximity, fuel transportation costs are much lower than they would be for a facility located in Missouri. See Tr. 318. By using a plant in Mississippi, GMO captures significant cost savings compared with producing electricity within its Missouri territory, for example at the South Harper facility. See GMO-102, Blunk Direct at 29-30. Company witness Wm. Edward Blunk explained his calculations in pre-filed testimony and at hearing. See Tr. 319-321. He summarized his findings as follows:

> Q: So based on the calculations you've done in your testimony, does it save the ratepayers money on transportation costs to use the Crossroads facility in Mississippi?
> A: Yes.
> Q: And is that savings sufficient to justify the transmission costs?
> A: Yes. You save more off the – you save more off the natural gas transportation than what the electric transmission is going to cost. [See Tr. 321:13-22.]

The evidence clearly showed that GMO is prudently incurring electric transmission costs because the overall Crossroads option results in savings to customers. Id. No party provided an alternative analysis and no witness rebutted the gas transportation costs to which Mr. Blunk testified. Consequently, it is undisputed that these transmission costs are more than offset by the gas transportation cost savings. The Commission's finding otherwise is contrary to the evidence on the record and is, therefore, unreasonable.

(ii) The Commission Unreasonably and Illogically Removed One Cost Element from the Least-Cost Option.

78. In making its determination to disallow transmission costs, the Commission ignored that fact that transmission costs were factored into the analysis when considering capacity options in 2007 and that when all costs are considered, Crossroads was the lowest total cost option. See GMO-111, Crawford Rebuttal at 3; Sch. BLC2010-9(HC); Tr. 913.

79. When Crossroads was offered in response to the March 2007 RFP, its book value included projected transmission costs of $11 million. See Tr. at 913-14. Even with the $11 million in transmission costs, which is more than double the actual transmission costs, Crossroads was the lowest cost option. See GMO-111, Crawford Rebuttal at 3; Sch. BLC2010-9(HC); Tr. 913-14.

80. The Commission cannot accept the Company's total cost option analysis of Crossroads as prudent, and then arbitrarily remove a single element of that analysis. Such decision-making is not reasonable, and is not supported by substantial and competent evidence on the record as a whole because electric transmission costs were an essential element of the Company's overall cost analysis of Crossroads, which the Commission found to be prudent. The Commission determined that Crossroads was prudent because it was the lowest-cost option, but then removed a cost component that led to that finding. In so doing, the Commission has impeached its own prudence determination. Accordingly, the Report and Order is unreasonable.

(iii) The Commission's Disallowance of FERC-approved Transmission Costs Violated the Filed Rate Doctrine and the Supremacy Clause of the U.S. Constitution Because it Unlawfully "Traps" Such Costs and Prevents Them From Being Recovered by the Company.

81. By allowing recovery of the value of Crossroads, the Commission found that GMO acted prudently when it put Crossroads in its generation fleet. However, the Commission then improperly excluded from GMO's rates the transmission component of the cost of service to utilize Crossroads power, even though Crossroads was overall (including the transmission cost component) the least cost solution to meet GMO's resource needs. By excluding Crossroads transmission costs from rates, the Commission denied recovery of costs that are the subject of a FERC-approved tariff in violation of the Filed Rate Doctrine.

82. The Filed Rate Doctrine developed as an outgrowth of federal preemption and the U.S. Constitution's Supremacy Clause. It "holds that interstate power rates fixed by the FERC must be given binding effect by state utility commissions determining intrastate rates." See Associated Natural Gas Co. v. PSC, 954 S.W.2d 520, 530 (Mo. App. W.D. 1997). Consequently, "a state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price." Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953, 965 (1986). Missouri courts have explicitly recognized and honored these concepts of federalism and the Filed Rate Doctrine. See Associated Natural Gas Co. v. PSC, 954 S.W.2d 520, 531 (Mo. App. W.D. 1997).

83. Ironically, in this proceeding the Commission has done exactly what it previously declared it lacks authority to do. See Order Consolidating Cases, Finding Jurisdiction to Proceed, and Directing the Parties to File a Proposed Procedural Schedule, In re Missouri Gas Energy's Purchased Gas Adjustment Tariff Revisions, Case No. GR-2001-382, 2002 WL 31492304 *2 (Sept. 10, 2002). It has decided that the FERC-approved interstate transmission

rate that GMO is paying for power from Crossroads is too high, and has, in effect, ordered the FERC tariff to be reduced to zero by denying recovery of the costs that the Company incurs regarding such service. By determining that it was not just and reasonable for GMO customers to pay the cost of purchased power from Crossroads, the Commission has explicitly infringed on the authority of FERC under the Federal Power Act, violated the Filed Rate Doctrine, and run afoul of the Supremacy Clause. See Report and Order at 59.

84. In finding that it is not barred from determining the prudence of buying power from Crossroads, the Commission misinterprets a key holding of the United States Supreme Court in Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953 (1986), which prohibited the "trapping" of the FERC-determined costs where a state commission denied a utility recovery of FERC-determined costs, in violation of the Filed Rate Doctrine. Id. at 970.

85. The Commission erroneously concluded that it may disallow FERC-approved transmission costs from language in Nantahala that a state commission may deem a quantity of power from a particular source "unreasonably excessive if lower cost power is available elsewhere." The Commission reads this language as stating that "FERC's rate-setting for a facility requires neither the purchase of power, nor approval of that purchase, from that facility." See Report and Order at 59. Such conclusion misses the point that Crossroads *was* the lowest cost alternative, and is identical to the erroneous "oversimplification" that caused the Supreme Court to reverse the decision of the North Carolina Supreme Court in Nantahala. 476 U.S. at 967.

86. Given the Commission's conclusion that Crossroads should be included in rate base, no other alternative offered lower costs for Missouri ratepayers. This finding is important because it distinguishes GMO's case from other cases where state bodies inquired about lower cost alternatives. See Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953, 972-73

(1986); Kentucky West Virginia Gas Co. v. Pennsylvania Pub. Util. Comm'n., 837 F.2d 600, 607-609 (3d Cir. 1988); Appalachian Power Co. v. Public Serv. Comm'n, 812 F.2d 898, 903 (4th Cir. 1987). That a state commission may inquire about lower cost alternatives in no way supports the Commission's decision to disallow FERC-approved transmission costs that are part and parcel of the *lowest* cost alternative for Missouri ratepayers.

87. The Commission could not lawfully lower the costs of the Crossroads option by disallowing FERC transmission costs that were included in GMO's analysis, as the evidence showed. Compelling GMO to absorb the cost of electricity transmitted under a federal tariff violates both the U.S. Constitution's Supremacy Clause and the Filed Rate Doctrine.

88. The Commission's refusal to allow the Company to recover electric transmission costs from Crossroads, which was placed in rate base as the most prudent option available, is unlawful, unreasonable, arbitrary, and capricious, and runs afoul of federal jurisdiction. As a result, the Report and Order is unjust, unlawful, unreasonable, arbitrary, capricious, not supported by substantial and competent evidence of record, and not supported by adequate findings of fact and conclusions of law.

WHEREFORE, Kansas City Power and Light Company and KCP&L Greater Missouri Operations Company respectfully request that the Commission clarify its Report and Order, as requested herein, and grant rehearing of its Report and Order, as more fully described herein.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the above and foregoing was served upon counsel of record on this 18th day of January, 2013.

/s/ Lisa A. Gilbreath

Attorney for Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company

EXHIBIT A

KCP&L Missouri
Electric Utility ROE Cases (2012)

Panel 1

T&D Utilities and Vertically-Integrated Utilities

T&D Utilities

No	Date	Company	State	ROE	Comment
1	5/29/2012	Commonwealth Edison	IL	10.05%	
2	6/14/2012	Orange and Rockland Utilities	NY	9.40%	
3	7/20/2012	Delmarva Power & Light	MD	9.81%	
4	7/20/2012	Potomac Electric Power	MD	9.31%	
5	9/19/2012	Ameren Illinois	IL	10.05%	
6	9/26/2012	Potomac Electric Power	DC	9.50%	
7	10/12/2012	Lone Star Transmission	TX	9.60%	
8	10/23/2012	Atlantic City Electric	NJ	9.75%	
9	11/29/2012	Delmarva Power & Light	DE	9.75%	
10	12/5/2012	Ameren Illinois	IL	9.71%	
11	12/5/2012	PPL Electric Utilities	PA	10.40%	
12	12/19/2012	Commonwealth Edison	IL	9.71%	
13	12/20/2012	Narragansett Electric	RI	9.50%	
Average T&D				**9.73%**	
			Min	**9.31%**	
			Max	**10.40%**	

Vertically-Integrated Utilities

No	Date	Company	State	ROE
1	1/25/2012	Duke Energy Carolinas	SC	10.50%
2	1/27/2012	Duke Energy Carolinas	NC	10.50%
3	2/15/2012	Indiana Michigan Power	MI	10.20%
4	2/23/2012	Idaho Power	OR	9.90%
5	2/27/2012	Gulf Power	FL	10.25%
6	2/29/2012	Northern States Power-Minnesota	ND	10.40%
7	3/29/2012	Northern States Power-Minnesota	MN	10.37%
8	4/4/2012	Hawaii Electric Light	HI	10.00%
9	4/26/2012	Public Service Co. of Colorado	CO	10.00%
10	5/2/2012	Maui Electric Company	HI	10.00%
11	5/7/2012	Puget Sound Energy	WA	9.80%
12	5/15/2012	Arizona Public Service	AZ	10.00%
13	6/7/2012	Consumers Energy	MI	10.30%
14	6/15/2012	Wisconsin Power and Light	WI	10.40%
15	6/18/2012	Cheyenne Light, Fuel and Power	WY	9.60%
16	6/19/2012	Northern States Power-Minnesota	SD	9.25%
17	6/26/2012	Wisconsin Electric Power	MI	10.10%
18	6/29/2012	Hawaiian Electric Company	HI	10.00%
19	7/9/2012	Oklahoma Gas & Electric	OK	10.20%
20	7/16/2012	PacifiCorp	WY	9.80%
21	9/13/2012	Entergy Texas	TX	9.80%
22	9/19/2012	PacifiCorp	UT	9.80%

Other Cases

No	Date	Company	State	ROE	Comment
1	1/3/2012	Appalachian Power	VA	11.40%	Generation rider
2	2/2/2012	Virginia Electric and Power	VA	11.40%	Generation rider
3	3/16/2012	Virginia Electric and Power	VA	12.40%	Generation rider
4	3/20/2012	Virginia Electric and Power	VA	11.40%	Generation rider
5	3/23/2012	Virginia Electric and Power	VA	11.40%	Generation rider
Average Other				**11.60%**	
Average All Utilities for 2012				**10.14%**	

Panel 2

Summary of Results by Quarter

T&D Utilities

By Quarter	1Q	2Q	3Q	4Q	Total
Avg. ROE		9.73%	9.67%	9.77%	**9.73%**
No. Cases	0	2	4	7	**13**

Vertically-Integrated Utilities

By Quarter	1Q	2Q	3Q	4Q	Total
Avg. ROE	10.30%	9.95%	9.90%	10.16%	**10.10%**
No. Cases	7	11	4	17	**39**

Other Cases

By Quarter	1Q	2Q	3Q	4Q	Total
ROE	11.60%				**11.60%**
No. Cases	5				**5**

All Utilities

By Quarter	1Q	2Q	3Q	4Q	Total
ROE	10.84%	9.92%	9.78%	10.05%	**10.15%**
No. Cases	12	13	8	24	**57**

Vertically-Integrated Utilities (continued)

No	Date	Company	State	ROE
23	10/24/2012	Wisconsin Public Service	WI	10.30%
24	11/9/2012	Madison Gas and Electric	WI	10.30%
25	11/28/2012	Wisconsin Electric Power	WI	10.40%
26	11/29/2012	California Pacific Electric	CA	9.88%
27	12/12/2012	Union Electric	MO	9.80%
28	12/13/2012	Florida Power & Light	FL	10.50%
29	12/13/2012	Kansas City Power & Light	KS	9.50%
30	12/14/2012	Northern States Power-WI	WI	10.40%
31	12/19/2012	South Carolina Electric & Gas	SC	10.25%
32	12/20/2012	Pacific Gas and Electric	CA	10.40%
33	12/20/2012	San Diego Gas & Electric	CA	10.30%
34	12/20/2012	Southern California Edison	CA	10.45%
35	12/20/2012	Kentucky Utilities	KY	10.25%
36	12/20/2012	Louisville Gas & Electric	KY	10.25%
37	12/20/2012	PacifiCorp	OR	9.80%
38	12/21/2012	Virginia Electric & Power	NC	10.20%
39	12/26/2012	Avista Corp.	WA	9.80%
Average Vertically-Integrated				**10.10%**
			Min	**9.25%**
			Max	**10.50%**

Source: Regulatory Research Associates Regulatory Focus: "Major Rate Case Decisions - Calendar 2012" (Jan. 17, 2012).

EXHIBIT A

ATTACHMENT 3

Order Denying Rehearing

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 30th day of January, 2013.

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2012-0174 Tracking No. YE-2013-0325

and

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	File No. ER-2012-0175 Tracking No. YE-2013-0326

ORDER DENYING REHEARING OF REPORT AND ORDER AND REHEARING OF ORDER APPROVING COMPLIANCE TARIFFS

Issue Date: January 30, 2013 Effective Date: January 30, 2013

The Missouri Public Service Commission is denying each application for rehearing ("application") related to the *Report and Order*[1] and each application related to the *Order Granting Expedited Treatment, Overruling Objection, and Approving Compliance Tariffs* ("compliance tariff order").[2] On January 18, the parties filed applications related to the *Report and Order* as follows.

File Nos. ER-2012-0174 and ER-2012-0175
Kansas City Power & Light Company ("KCPL") and KCP&L Greater Missouri Operations Company ("GMO")[3]
Southern Union Company d/b/a Missouri Gas Energy
Midwest Energy Consumers Group ("MECG")

[1] Issued on January 9. All dates are in 2013.

[2] Issued on January 23.

[3] Styled *Application for Rehearing and/or Motion for Clarification of KCP&L and GMO*.

File No. ER-2012-0174	File No. ER-2012-0175
Midwest Energy Consumers Group, Missouri Industrial Energy Consumers, and Praxair, Inc.	AARP
	Consumers Council Of Missouri

Responses to the application of KCPL and GMO were filed by Dogwood Energy, LLC in File No. ER-2012-0175, and by Union Electric Company d/b/a Ameren Missouri ("Ameren") in both actions, on January 28; and by MECG in both actions on January 29. On January 25, MECG filed an application related to the compliance tariff order in both actions. The Commission grants an application for rehearing if "in its judgment sufficient reason therefor be made to appear."[4] Under that standard, and on consideration of the applications and responses, the Commission will deny the applications for rehearing.

THE COMMISSION ORDERS THAT:

1. Each application for rehearing is denied.
2. This order is effective immediately on issuance.

BY THE COMMISSION

(S E A L)

Shelley Brueggemann

Shelley Brueggemann
Acting Secretary

Gunn, Chm., Jarrett, R. Kenney, Stoll,
and W. Kenney, CC., concur.

Jordan, Senior Regulatory Law Judge

[4] Section 386.500.1, RSMo 2000.

ATTACHMENT 4

RECONCILIATION

Kansas City Power & Light
MPSC Case No. ER-2012-0174
Reconciliation of Issues Decided by the Commission
Revenue Requirement Impact

		Change Revenue Requirement
ROE		
9.7% Per Order	67,390,893	
9.1% Per OPC	56,955,758	(10,435,135)
9.5% Per FEA	63,901,664	(3,489,229)
9.78% Per Staff	68,753,293	1,362,400
10.3% Per Company	77,790,775	10,399,882
Cost of Debt		
6.187% Per Staff	65,114,196	(2,276,697)
Capital Structure		
Eliminate OCI per Company	67,951,683	560,790
Debt/Equity Cost Structure per OPC, MECG	62,368,957	(5,021,936)
Class Cost of Service		
Class Cost of Service per Company, Staff, MECG, MIEC	67,390,893	0
Rate Design - Winter, Space Heating, & All-Electric		
Space Heating Elimination per MGE	67,390,721	(172)
Winter Heating Blocks per Company	67,392,902	2,009
Customer Charge per Company, Staff	67,391,670	777

Kansas City Power & Light
MPSC Case No. ER-2012-0174

ROE
Issue: **9.1% Per OPC**
Value: **(10,435,135)**

	Impact	
	Amount	Percent
Large Power	(1,866,004)	-1.31%
Large General Service	(2,432,047)	-1.36%
Medium General Service	(1,428,892)	-1.39%
Small General Service	(700,878)	-1.46%
Residential	(3,875,643)	-1.36%
Lighting	(131,670)	-1.36%
Total	(10,435,135)	-1.36%

ROE
Issue: **9.5% Per FEA**
Value: **(3,489,229)**

	Impact	
	Amount	Percent
Large Power	(623,942)	-0.44%
Large General Service	(813,211)	-0.46%
Medium General Service	(477,783)	-0.46%
Small General Service	(234,355)	-0.49%
Residential	(1,295,911)	-0.46%
Lighting	(44,027)	-0.46%
Total	(3,489,229)	-0.46%

ROE
Issue: **9.78% Per Staff**
Value: **1,362,400**

	Impact	
	Amount	Percent
Large Power	243,624	0.17%
Large General Service	317,525	0.18%
Medium General Service	186,555	0.18%
Small General Service	91,506	0.19%
Residential	506,000	0.18%
Lighting	17,191	0.18%
Total	1,362,400	0.18%

ROE
Issue: **10.3% Per Company**
Value: **10,399,882**

	Impact	
	Amount	Percent
Large Power	1,859,701	1.30%

Large General Service	2,423,831	1.36%
Medium General Service	1,424,064	1.39%
Small General Service	698,510	1.45%
Residential	3,862,550	1.36%
Lighting	131,225	1.36%
Total	10,399,882	1.36%

Cost of Debt
Issue: **6.187% Per Staff**
Value: **(2,276,697)**

	Impact Amount	Impact Percent
Large Power	(407,118)	-0.29%
Large General Service	(530,615)	-0.30%
Medium General Service	(311,750)	-0.30%
Small General Service	(152,915)	-0.32%
Residential	(845,573)	-0.30%
Lighting	(28,727)	-0.30%
Total	(2,276,697)	-0.30%

Capital Structure
Issue: **Eliminate OCI per Company**
Value: **560,790**

	Impact Amount	Impact Percent
Large Power	100,280	0.07%
Large General Service	130,700	0.07%
Medium General Service	76,789	0.07%
Small General Service	37,666	0.08%
Residential	208,279	0.07%
Lighting	7,076	0.07%
Total	560,790	0.07%

Capital Structure
Issue: **Debt/Equity Cost Structure per OPC, MECG**
Value: **(5,021,936)**

	Impact Amount	Impact Percent
Large Power	(898,020)	-0.63%
Large General Service	(1,170,429)	-0.66%
Medium General Service	(687,658)	-0.67%
Small General Service	(337,299)	-0.70%
Residential	(1,865,163)	-0.66%
Lighting	(63,367)	-0.66%
Total	(5,021,936)	-0.66%

Class Cost of Service
Issue: **Class Cost of Service per Company, Staff, MECG, MIEC**

Value: **0**

	Impact Amount	Impact Percent
Large Power	(6,212,284)	-4.36%
Large General Service	(982,347)	-0.55%
Medium General Service	1,562,051	1.52%
Small General Service	3,036,269	6.30%
Residential	2,596,310	0.91%
Lighting	-	0.00%
Total	(0)	0.00%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Space Heating Elimination per MGE**
Value: **(172)**

	Impact Amount	Impact Percent
RATE A (GENERAL USE)	(4,712,888)	-2.36%
RATE B (GENERAL USE WITH SPACE HEAT - ONE METER)	3,687,207	7.81%
RATE C (GENERAL USE AND SPACE HEAT - 2 METERS)	1,024,581	7.95%
MO RESIDENTIAL OTHER USE	(160)	-0.43%
MO RESIDENTIAL TIME-OF-DAY	1,088	1.87%
Total	(172)	0.00%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Winter Heating Blocks per Company**
Value: **2,009**

	Impact Amount	Impact Percent
RATE A (GENERAL USE)	863,733	0.44%
RATE B (GENERAL USE WITH SPACE HEAT - ONE METER)	(773,050)	-1.64%
RATE C (GENERAL USE AND SPACE HEAT - 2 METERS)	(90,407)	-0.70%
MO RESIDENTIAL TIME-OF-DAY	248	0.43%
MO RESIDENTIAL OTHER USE	161	0.44%
SECONDARY VOLTAGE - SGSS	28,334	0.07%
PRIMARY VOLTAGE - SGSP	220	0.09%
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - SGSSA	(29,543)	-1.89%
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - SGSPA	-	0.00%
SECONDARY VOLTAGE, SPACE HEATING (TWO METER) - SGSSH	421	0.07%
SECONDARY VOLTAGE UNMETERED - SGSSU	796	0.09%
SECONDARY VOLTAGE - MGSS	115,352	0.14%
PRIMARY VOLTAGE - MGSP	1,133	0.13%
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - MGSSA	(117,493)	-1.30%
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - MGSPA	(496)	-1.13%
SECONDARY VOLTAGE, SPACE HEATING (TWO METER) - MGSSH	2,269	0.13%
SECONDARY VOLTAGE - LGSS	419,156	0.49%
PRIMARY VOLTAGE - LGSP	86,110	0.50%
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSSA	(423,242)	-0.95%
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSPA	(105,573)	-0.94%
SECONDARY VOLTAGE, SPACE HEAT (TWO METER) - LGSSH	23,882	0.54%
Total	2,009	0.00%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Customer Charge per Company, Staff**
Value: **777**

	Impact	
	Amount	Percent
RATE A (GENERAL USE)	33,627	0.02%
RATE B (GENERAL USE WITH SPACE HEAT - ONE METER)	(44,762)	-0.10%
RATE C (GENERAL USE AND SPACE HEAT - 2 METERS)	11,849	0.09%
MO RESIDENTIAL TIME-OF-DAY	74	0.13%
MO RESIDENTIAL OTHER USE	(11)	-0.03%
Total	777	0.00%

	A	B	C	D
1	**MO RESIDENTIAL**			
2	**RATE A (GENERAL USE)**			
3				
4	**SUMMER**			
5				
6			**BILLING UNITS**	
7				
8		CUSTOMER COUNT	697,173.3	
9				
10		KWH:		
11		0 - 600	394,581,445.9	
12		601 - 1000	179,464,112.2	
13		1000+	241,023,183.0	
14			815,068,741	
15				
16				
17				
18				
19				
20				
21	**WINTER**			
22				
23			**BILLING UNITS**	
24				
25		CUSTOMER COUNT	1,558,895.9	
26				
27		KWH:		
28		0 - 600	678,290,264.6	
29		601 - 1000	195,947,049.9	
30		1000+	208,912,407.5	
31			1,083,149,722	
32				
33				
34				
35				
36				
37				
38	**ANNUAL**		1,898,218,463	
39				

	A	B	C	D
40	**MO RESIDENTIAL**			
41	**RATE B (GENERAL USE WITH SPACE HEAT - ONE METER)**			
42				
43	**SUMMER**			
44				
45			**BILLING UNITS**	
46				
47		CUSTOMER COUNT	135,858.3	
48				
49		KWH:		
50		0 - 1000	124,210,310.2	
51		1000+	54,414,530.6	
52			178,624,841	
53				
54				
55				
56				
57				
58				
59	**WINTER**			
60				
61			**BILLING UNITS**	
62				
63		CUSTOMER COUNT	347,617.3	
64				
65		KWH:		
66		0 - 1000	241,259,090.3	
67		1000+	109,403,780.2	
68			350,662,870	
69				
70				
71				
72				
73				
74				
75	**ANNUAL**		529,287,711	
76				
77				

	A	B	C	D
78	**MO RESIDENTIAL**			
79	**RATE C (GENERAL USE AND SPACE HEAT - 2 METERS)**			
80				
81	**SUMMER**			
82				
83			**BILLING UNITS**	
84				
85		CUSTOMER COUNT	41,264.8	
86			41,264.8	
87				
88		KWH:		
89		0 - 600	24,896,571.2	
90		601 - 1000	6,872,724.1	
91		1000+	9,076,197.5	
92			40,845,493	
93				
94				
95				
96				
97				
98				
99				
100				
101	**WINTER**			
102				
103			**BILLING UNITS**	
104				
105		CUSTOMER COUNT	87,017.8	
106			87,017.8	
107				
108		KWH:		
109		0 - 600	36,061,578.0	
110		601 - 1000	7,596,616.8	
111		1000+	5,818,461.6	
112			49,476,656	
113				
114		HEAT KWH	55,803,862.8	
115				
116				
117				
118				
119				
120				
121				
122	**ANNUAL**		146,126,012	
123				
124				

	A	B	C	D
125	**MO RESIDENTIAL TIME-OF-DAY**			
127	**SUMMER**			
129			**BILLING UNITS**	
131		CUSTOMER COUNT	141.7	
133		KWH:		
134		On-Peak	57,677.3	
135		Off-Peak	195,288.6	
136			252,966	
143	**WINTER**			
145			**BILLING UNITS**	
147		CUSTOMER COUNT	325.6	
149		KWH:		
150		All KWH	335,067.8	
158	**ANNUAL**		588,034	

	A	B	C	D
161	**MO RESIDENTIAL OTHER USE**			
162				
163	**SUMMER**			
164				
165			**BILLING UNITS**	
166				
167		CUSTOMER COUNT	374.0	
168				
169		KWH:		
170		All KWH	79,951.0	
171			79,951	
172				
173				
174				
175				
176				
177				
178	**WINTER**			
179				
180			**BILLING UNITS**	
181				
182		CUSTOMER COUNT	26.2	
183				
184		KWH:		
185		All KWH	197,475.7	
186				
187				
188				
189				
190				
191				
192				
193	**ANNUAL**		277,427	
194				

	A	B	C	D
1	**MO SMALL GENERAL**			
2	**SECONDARY VOLTAGE - SGSS**			
3				
4	**SUMMER**			
5				
6			**BILLING UNITS**	
7				
8		A: CUSTOMER CHARGE		
9		Metered Service:		
10		0-24 KW	78,003.1	
11		25-199 KW	4,907.4	
12		200-999 KW	65.4	
13		1001+ KW	0.9	
14		Unmetered Service	-	
15		Separately Metered Space Heat	-	
16			82,977	
17		B: FACILITIES CHARGE		
18		0-25 KW	-	
19		26+ KW	106,104.8	
20			106,105	
21		C: ENERGY CHARGE		
22		0-180 hrs use per month	94,463,856.1	
23		181-360 hrs use per month	39,980,304.9	
24		361+ hrs use per month	10,257,411.3	
25			144,701,572	
26				
27		D: SEPARATELY METERED SPACE HEAT	-	
28				
29				
30	**WINTER**			
31				
32			**BILLING UNITS**	
33				
34		A: CUSTOMER CHARGE		
35		Metered Service:		
36		0-24 KW	188,678.5	
37		25-199 KW	11,506.8	
38		200-999 KW	132.0	
39		1001+ KW	4.1	
40		Unmetered Service	-	
41		Separately Metered Space Heat	-	
42			200,321	
43		B: FACILITIES CHARGE		
44		0-25 KW	-	
45		26+ KW	248,923.3	
46			248,923	
47		C: ENERGY CHARGE		
48		0-180 hrs use per month	148,220,941.4	
49		181-360 hrs use per month	59,356,073.0	
50		361+ hrs use per month	21,008,884.5	
51			228,585,899	
52				
53		D: SEPARATELY METERED SPACE HEAT	-	
54				
55	**ANNUAL**		373,287,471	
56				

MO SMALL GENERAL

PRIMARY VOLTAGE - SGSP

SUMMER		
		BILLING UNITS
	A: CUSTOMER CHARGE	
	Metered Service:	
	0-24 KW	121.6
	25-199 KW	26.3
	200-999 KW	20.3
	1001+ KW	6
	Unmetered Service	-
	Separately Metered Space Heat	-
		174
	B: FACILITIES CHARGE	
	0-25 KW	-
	26+ KW	14,204.6
		14,205
	C: ENERGY CHARGE	
	0-180 hrs use per month	587,241.0
	181-360 hrs use per month	130,126.4
	361+ hrs use per month	16,357.7
		733,725
	D: SEPARATELY METERED SPACE HEAT	-
WINTER		
		BILLING UNITS
	A: CUSTOMER CHARGE	
	Metered Service:	
	0-24 KW	222.3
	25-199 KW	52.3
	200-999 KW	29.1
	1001+ KW	-
	Unmetered Service	-
	Separately Metered Space Heat	-
		304
	B: FACILITIES CHARGE	
	0-25 KW	-
	26+ KW	19,555.7
		19,556
	C: ENERGY CHARGE	
	0-180 hrs use per month	485,411.1
	181-360 hrs use per month	183,496.9
	361+ hrs use per month	48,950.2
		717,858
	D: SEPARATELY METERED SPACE HEAT	-
ANNUAL		1,451,583

	A	B	C	D
112	**MO SMALL GENERAL**			
113	**SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - SGSSA**			
114				
115	**SUMMER**			
116				
117			**BILLING UNITS**	
118				
119		A: CUSTOMER CHARGE		
120		Metered Service:		
121		0-24 KW	1,175.2	
122		25-199 KW	318.6	
123		200-999 KW	2.9	
124		1001+ KW	-	
125		Unmetered Service	-	
126		Separately Metered Space Heat	-	
127			1,497	
128		B: FACILITIES CHARGE		
129		0-25 KW	-	
130		26+ KW	5,830.1	
131			5,830	
132		C: ENERGY CHARGE		
133		0-180 hrs use per month	2,967,801.4	
134		181-360 hrs use per month	1,519,658.8	
135		361+ hrs use per month	487,640.0	
136			4,975,100	
137				
138		D: SEPARATELY METERED SPACE HEAT	-	
139				
140	**WINTER**			
141				
142			**BILLING UNITS**	
143				
144		A: CUSTOMER CHARGE		
145		Metered Service:		
146		0-24 KW	3,292.9	
147		25-199 KW	899.6	
148		200-999 KW	7.9	
149		1001+ KW	-	
150		Unmetered Service	-	
151		Separately Metered Space Heat	-	
152			4,200	
153		B: FACILITIES CHARGE		
154		0-25 KW	-	
155		26+ KW	15,970.3	
156			15,970	
157		C: ENERGY CHARGE		
158		0-180 hrs use per month	6,465,019.5	
159		181-360 hrs use per month	2,685,543.3	
160		361+ hrs use per month	1,358,315.5	
161			10,508,878	
162				
163		D: SEPARATELY METERED SPACE HEAT	-	
164				
165	**ANNUAL**		15,483,979	
166				

	A	B	C	D
167	**MO SMALL GENERAL**			
168	**PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - SGSPA**			
169				
170	**SUMMER**			
171				
172			**BILLING UNITS**	
173				
174		A: CUSTOMER CHARGE		
175		Metered Service:		
176		0-24 KW	-	
177		25-199 KW	-	
178		200-999 KW	-	
179		1001+ KW	-	
180		Unmetered Service	-	
181		Separately Metered Space Heat	-	
182			-	
183		B: FACILITIES CHARGE		
184		0-25 KW	-	
185		26+ KW	-	
186			-	
187		C: ENERGY CHARGE		
188		0-180 hrs use per month	-	
189		181-360 hrs use per month	-	
190		361+ hrs use per month	-	
191			-	
192				
193		D: SEPARATELY METERED SPACE HEAT	-	
194				
195	**WINTER**			
196				
197			**BILLING UNITS**	
198				
199		A: CUSTOMER CHARGE		
200		Metered Service:		
201		0-24 KW	-	
202		25-199 KW	-	
203		200-999 KW	-	
204		1001+ KW	-	
205		Unmetered Service	-	
206		Separately Metered Space Heat	-	
207			-	
208		B: FACILITIES CHARGE		
209		0-25 KW	-	
210		26+ KW	-	
211			-	
212		C: ENERGY CHARGE		
213		0-180 hrs use per month	-	
214		181-360 hrs use per month	-	
215		361+ hrs use per month	-	
216			-	
217				
218		D: SEPARATELY METERED SPACE HEAT	-	
219				
220	**ANNUAL**		-	
221				

KANSAS CITY POWER & LIGHT COMPANY

MO SMALL GENERAL
SECONDARY VOLTAGE, SPACE HEATING (TWO METER) - SGSSH

SUMMER

	BILLING UNITS
A: CUSTOMER CHARGE	
Metered Service:	
0-24 KW	596.9
25-199 KW	240.8
200-999 KW	7.3
1001+ KW	-
Unmetered Service	-
Separately Metered Space Heat	844.8
	1,690
B: FACILITIES CHARGE	
0-25 KW	
26+ KW	6,105.9
	6,106
C: ENERGY CHARGE	
0-180 hrs use per month	1,346,108.7
181-360 hrs use per month	381,250.0
361+ hrs use per month	65,212.7
	1,792,571
D: SEPARATELY METERED SPACE HEAT	-

WINTER

	BILLING UNITS
A: CUSTOMER CHARGE	
Metered Service:	
0-24 KW	1,257.5
25-199 KW	500.6
200-999 KW	12.4
1001+ KW	-
Unmetered Service	-
Separately Metered Space Heat	1,770.7
	3,541
B: FACILITIES CHARGE	
0-25 KW	
26+ KW	12,868.7
	12,869
C: ENERGY CHARGE	
0-180 hrs use per month	1,363,482.1
181-360 hrs use per month	371,387.7
361+ hrs use per month	103,521.0
	1,838,391
D: SEPARATELY METERED SPACE HEAT	1,929,727.3

ANNUAL	5,560,690

MO SMALL GENERAL
SECONDARY VOLTAGE - SGSSU

SUMMER

	BILLING UNITS
A: CUSTOMER CHARGE	
Metered Service:	
0-24 KW	-
25-199 KW	-
200-999 KW	-
1001+ KW	-
Unmetered Service	9,226.5
Separately Metered Space Heat	-
	9,227
B: FACILITIES CHARGE	
0-25 KW	-
26+ KW	-
	-
C: ENERGY CHARGE	
0-180 hrs use per month	1,423,670.0
181-360 hrs use per month	846,099.3
361+ hrs use per month	233,955.4
	2,503,725
D: SEPARATELY METERED SPACE HEAT	-

WINTER

	BILLING UNITS
A: CUSTOMER CHARGE	
Metered Service:	
0-24 KW	-
25-199 KW	-
200-999 KW	-
1001+ KW	-
Unmetered Service	23,976.6
Separately Metered Space Heat	-
	23,977
B: FACILITIES CHARGE	
0-25 KW	-
26+ KW	-
	-
C: ENERGY CHARGE	
0-180 hrs use per month	2,799,307.2
181-360 hrs use per month	1,863,796.5
361+ hrs use per month	468,926.4
	5,132,030
D: SEPARATELY METERED SPACE HEAT	-
ANNUAL	7,635,755

	A	B	C	D
1	**MO MEDIUM GENERAL**			
2	**SECONDARY VOLTAGE - MGSS**			
3				
4	**SUMMER**			
5				
6			**BILLING UNITS**	
7				
8		A: CUSTOMER CHARGE		
9		0-24 KW	26.0	
10		25-199 KW	16,723.0	
11		200-999 KW	532.3	
12		1001+ KW	5.1	
13		Separately Metered Space Heat	-	
14			17,286	
15				
16		B: FACILITIES CHARGE	1,212,400.0	
17				
18		C: DEMAND CHARGE	1,179,227.2	
19				
20		D: ENERGY CHARGE		
21		0-180 hrs use per month	197,488,920.9	
22		181-360 hrs use per month	129,064,402.9	
23		361+ hrs use per month	39,509,003.8	
24			366,062,328	
25				
26		E: SEPARATELY METERED SPACE HEAT	-	
27				
28	**WINTER**			
29				
30			**BILLING UNITS**	
31				
32		A: CUSTOMER CHARGE		
33		0-24 KW	53.2	
34		25-199 KW	39,951.3	
35		200-999 KW	1,247.4	
36		1001+ KW	12.2	
37		Separately Metered Space Heat	-	
38			41,264	
39				
40		B: FACILITIES CHARGE	2,880,208.0	
41				
42		C: DEMAND CHARGE	2,012,745.7	
43				
44		D: ENERGY CHARGE		
45		0-180 hrs use per month	324,820,162.0	
46		181-360 hrs use per month	201,101,903.3	
47		361+ hrs use per month	66,354,516.2	
48			592,276,581	
49				
50		E: SEPARATELY METERED SPACE HEAT	-	
51				
52		F: REACTIVE DEMAND ADJUSTMENT	29,072	
53				
54	**ANNUAL**		958,338,909	
55				
56				

MO MEDIUM GENERAL
PRIMARY VOLTAGE - MGSP

SUMMER		
		BILLING UNITS
	A: CUSTOMER CHARGE	
	0-24 KW	-
	25-199 KW	94.3
	200-999 KW	17.3
	1001+ KW	1.7
	Separately Metered Space Heat	-
		113
	B: FACILITIES CHARGE	14,723.6
	C: DEMAND CHARGE	15,626.3
	D: ENERGY CHARGE	
	0-180 hrs use per month	1,929,964.9
	181-360 hrs use per month	1,238,859.6
	361+ hrs use per month	529,412.7
		3,698,237
	E: SEPARATELY METERED SPACE HEAT	-
	F: REACTIVE DEMAND ADJUSTMENT	831
WINTER		
		BILLING UNITS
	A: CUSTOMER CHARGE	
	0-24 KW	-
	25-199 KW	253.9
	200-999 KW	46.2
	1001+ KW	4.6
	Separately Metered Space Heat	-
		305
	B: FACILITIES CHARGE	41,799.9
	C: DEMAND CHARGE	19,767.0
	D: ENERGY CHARGE	
	0-180 hrs use per month	3,116,347.7
	181-360 hrs use per month	2,040,043.5
	361+ hrs use per month	999,450.4
		6,155,842
	E: SEPARATELY METERED SPACE HEAT	-
	F: REACTIVE DEMAND ADJUSTMENT	2,459
ANNUAL		9,854,079

A	B	C	D
MO MEDIUM GENERAL			
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - MGSSA			
SUMMER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
	0-24 KW	-	
	25-199 KW	1,202.0	
	200-999 KW	107.2	
	1001+ KW	-	
	Separately Metered Space Heat	-	
		1,309	
	B: FACILITIES CHARGE	128,236.6	
	C: DEMAND CHARGE	111,554.9	
	D: ENERGY CHARGE		
	0-180 hrs use per month	19,356,242.0	
	181-360 hrs use per month	14,932,565.2	
	361+ hrs use per month	5,214,579.4	
		39,503,387	
	E: SEPARATELY METERED SPACE HEAT	-	
WINTER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
	0-24 KW	-	
	25-199 KW	3,170.5	
	200-999 KW	287.3	
	1001+ KW	-	
	Separately Metered Space Heat	-	
		3,458	
	B: FACILITIES CHARGE	340,631.5	
	C: DEMAND CHARGE	230,639.8	
	D: ENERGY CHARGE		
	0-180 hrs use per month	39,832,271.1	
	181-360 hrs use per month	27,326,074.5	
	361+ hrs use per month	9,392,840.7	
		76,551,186	
	E: SEPARATELY METERED SPACE HEAT	-	
ANNUAL		116,054,573	

A	B	C
MO MEDIUM GENERAL		
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - MGSPA		
SUMMER		
		BILLING UNITS
	A: CUSTOMER CHARGE	
	0-24 KW	-
	25-199 KW	1.8
	200-999 KW	1.6
	1001+ KW	-
	Separately Metered Space Heat	-
		3
	B: FACILITIES CHARGE	772.0
	C: DEMAND CHARGE	776.9
	D: ENERGY CHARGE	
	0-180 hrs use per month	136,595.2
	181-360 hrs use per month	77,072.4
	361+ hrs use per month	11,892.6
		225,560
	E: SEPARATELY METERED SPACE HEAT	-
WINTER		
		BILLING UNITS
	A: CUSTOMER CHARGE	
	0-24 KW	-
	25-199 KW	4.2
	200-999 KW	3.9
	1001+ KW	-
	Separately Metered Space Heat	-
		8
	B: FACILITIES CHARGE	1,792.5
	C: DEMAND CHARGE	1,015.6
	D: ENERGY CHARGE	
	0-180 hrs use per month	174,446.4
	181-360 hrs use per month	123,370.9
	361+ hrs use per month	29,481.5
		327,299
	E: SEPARATELY METERED SPACE HEAT	-
ANNUAL		552,859

	A	B	C	D
219	**MO MEDIUM GENERAL**			
220	**SECONDARY VOLTAGE, SPACE HEATING (TWO METER) - MGSSH**			
221				
222	**SUMMER**			
223				
224			**BILLING UNITS**	
225				
226		A: CUSTOMER CHARGE		
227		0-24 KW	-	
228		25-199 KW	309.7	
229		200-999 KW	33.6	
230		1001+ KW	-	
231		Separately Metered Space Heat	343.2	
232			686	
233				
234		B: FACILITIES CHARGE	33,126.7	
235				
236		C: DEMAND CHARGE	21,746.3	
237				
238		D: ENERGY CHARGE		
239		0-180 hrs use per month	3,659,247.5	
240		181-360 hrs use per month	2,749,949.5	
241		361+ hrs use per month	1,101,545.0	
242			7,510,742	
243				
244		E: SEPARATELY METERED SPACE HEAT	-	
245				
246	**WINTER**			
247				
248			**BILLING UNITS**	
249				
250		A: CUSTOMER CHARGE		
251		0-24 KW	-	
252		25-199 KW	605.2	
253		200-999 KW	65.5	
254		1001+ KW	-	
255		Separately Metered Space Heat	670.7	
256			1,341	
257				
258		B: FACILITIES CHARGE	64,678.5	
259				
260		C: DEMAND CHARGE	45,028.6	
261				
262		D: ENERGY CHARGE		
263		0-180 hrs use per month	3,513,637.1	
264		181-360 hrs use per month	2,549,511.7	
265		361+ hrs use per month	1,014,980.8	
266			7,078,130	
267				
268		E: SEPARATELY METERED SPACE HEAT	5,679,492.8	
269				
270	**ANNUAL**		20,268,364	
271				

	A	B	C	D
1	**MO LARGE GENERAL**			
2	**SECONDARY VOLTAGE - LGSS**			
3				
4	**SUMMER**			
5				
6			**BILLING UNITS**	
7				
8		A: CUSTOMER CHARGE		
9		0-24 KW	-	
10		25-199 KW	-	
11		200-999 KW	2,270.8	
12		1001+ KW	98.0	
13		Separately Metered Space Heat	-	
14			2,369	
15				
16		B: FACILITIES CHARGE	1,091,204.4	
17				
18		C: DEMAND CHARGE	1,097,514.4	
19				
20		D: ENERGY CHARGE		
21		0-180 hrs use per month	189,176,099.4	
22		181-360 hrs use per month	152,208,363.8	
23		361+ hrs use per month	75,213,540.5	
24			416,598,004	
25				
26		E: SEPARATELY METERED SPACE HEAT	-	
27				
28		F: REACTIVE DEMAND ADJUSTMENT	-	
29				
30	**WINTER**			
31				
32			**BILLING UNITS**	
33				
34		A: CUSTOMER CHARGE		
35		0-24 KW	-	
36		25-199 KW	-	
37		200-999 KW	5,492.4	
38		1001+ KW	221.6	
39		Separately Metered Space Heat	-	
40			5,714	
41				
42		B: FACILITIES CHARGE	2,577,685.5	
43				
44		C: DEMAND CHARGE	1,923,964.5	
45				
46		D: ENERGY CHARGE		
47		0-180 hrs use per month	321,882,384.7	
48		181-360 hrs use per month	256,846,147.5	
49		361+ hrs use per month	121,070,960.7	
50			699,799,493	
51				
52		E: SEPARATELY METERED SPACE HEAT	-	
53				
54		F: REACTIVE DEMAND ADJUSTMENT	2,315	
55				
56	**ANNUAL ENERGY/REVENUE**		1,116,397,497	
57				

A	B	C	D
MO LARGE GENERAL			
PRIMARY VOLTAGE - LGSP			
SUMMER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
	0-24 KW	-	
	25-199 KW	-	
	200-999 KW	206.7	
	1001+ KW	68.6	
	Separately Metered Space Heat	-	
		275	
	B: FACILITIES CHARGE	230,336.3	
	C: DEMAND CHARGE	224,850.1	
	D: ENERGY CHARGE		
	0-180 hrs use per month	39,367,907.9	
	181-360 hrs use per month	30,230,176.1	
	361+ hrs use per month	12,894,022.3	
		82,492,106	
	E: SEPARATELY METERED SPACE HEAT	-	
	F: REACTIVE DEMAND ADJUSTMENT	23,666	
WINTER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
	0-24 KW	-	
	25-199 KW	-	
	200-999 KW	505.1	
	1001+ KW	158.3	
	Separately Metered Space Heat	-	
		663	
	B: FACILITIES CHARGE	551,900.1	
	C: DEMAND CHARGE	399,251.9	
	D: ENERGY CHARGE		
	0-180 hrs use per month	69,879,321.4	
	181-360 hrs use per month	52,182,873.6	
	361+ hrs use per month	25,538,340.9	
		147,600,536	
	E: SEPARATELY METERED SPACE HEAT	-	
	F: REACTIVE DEMAND ADJUSTMENT	46,706	
ANNUAL ENERGY/REVENUE		230,092,642	

MO LARGE GENERAL
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSSA

SUMMER

	BILLING UNITS
A: CUSTOMER CHARGE	
0-24 KW	-
25-199 KW	-
200-999 KW	524.3
1001+ KW	160.3
Separately Metered Space Heat	-
	685
B: FACILITIES CHARGE	532,944.6
C: DEMAND CHARGE	495,428.4
D: ENERGY CHARGE	
0-180 hrs use per month	89,131,613.6
181-360 hrs use per month	82,149,453.5
361+ hrs use per month	49,123,653.9
	220,404,721
E: SEPARATELY METERED SPACE HEAT	-
F: REACTIVE DEMAND ADJUSTMENT	3,279

WINTER

	BILLING UNITS
A: CUSTOMER CHARGE	
0-24 KW	-
25-199 KW	-
200-999 KW	1,382.5
1001+ KW	429.8
Separately Metered Space Heat	-
	1,812
B: FACILITIES CHARGE	1,414,775.8
C: DEMAND CHARGE	1,028,689.0
D: ENERGY CHARGE	
0-180 hrs use per month	186,068,561.5
181-360 hrs use per month	165,743,452.6
361+ hrs use per month	95,439,732.3
	447,251,746
E: SEPARATELY METERED SPACE HEAT	-
F: REACTIVE DEMAND ADJUSTMENT	3,952

ANNUAL ENERGY/REVENUE 667,656,467

A	B	C	D
MO LARGE GENERAL			
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSPA			
SUMMER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
	0-24 KW	-	
	25-199 KW	-	
	200-999 KW	6.9	
	1001+ KW	39.7	
	Separately Metered Space Heat	-	
		47	
	B: FACILITIES CHARGE	158,264.2	
	C: DEMAND CHARGE	130,409.1	
	D: ENERGY CHARGE		
	0-180 hrs use per month	23,535,784.1	
	181-360 hrs use per month	20,788,316.1	
	361+ hrs use per month	15,059,512.7	
		59,383,613	
	E: SEPARATELY METERED SPACE HEAT	-	
	F: REACTIVE DEMAND ADJUSTMENT	8,699	
WINTER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
	0-24 KW	-	
	25-199 KW	-	
	200-999 KW	17.1	
	1001+ KW	104.3	
	Separately Metered Space Heat	-	
		121	
	B: FACILITIES CHARGE	411,116.8	
	C: DEMAND CHARGE	265,681.9	
	D: ENERGY CHARGE		
	0-180 hrs use per month	47,766,160.1	
	181-360 hrs use per month	38,736,622.1	
	361+ hrs use per month	24,223,435.3	
		110,726,217	
	E: SEPARATELY METERED SPACE HEAT	-	
	F: REACTIVE DEMAND ADJUSTMENT	13,175	
	ADJUSTMENT		
ANNUAL ENERGY/REVENUE		170,109,830	

	A	B	C	D
232	**MO LARGE GENERAL**			
233	**SECONDARY VOLTAGE, SPACE HEAT (TWO METER) - LGSSH**			
234				
235	**SUMMER**			
236				
237			**BILLING UNITS**	
238		A: CUSTOMER CHARGE		
239		0-24 KW	-	
240		25-199 KW	-	
241		200-999 KW	129.7	
242		1001+ KW	15.8	
243		Separately Metered Space Heat	145.5	
244			291	
245				
246		B: FACILITIES CHARGE	68,972.6	
247				
248		C: DEMAND CHARGE	55,417.4	
249				
250		D: ENERGY CHARGE		
251		0-180 hrs use per month	9,269,916.3	
252		181-360 hrs use per month	7,805,293.2	
253		361+ hrs use per month	3,924,899.0	
254			21,000,108	
255				
256		E: SEPARATELY METERED SPACE HEAT	-	
257				
258		F: REACTIVE DEMAND ADJUSTMENT	-	
259				
260	**WINTER**			
261				
262			**BILLING UNITS**	
263		A: CUSTOMER CHARGE		
264		0-24 KW	-	
265		25-199 KW	-	
266		200-999 KW	254.5	
267		1001+ KW	31.0	
268		Separately Metered Space Heat	285.5	
269			571	
270				
271		B: FACILITIES CHARGE	139,046.6	
272				
273		C: DEMAND CHARGE	111,260.0	
274				
275		D: ENERGY CHARGE		
276		0-180 hrs use per month	9,026,533.9	
277		181-360 hrs use per month	7,546,381.9	
278		361+ hrs use per month	3,702,957.7	
279			20,275,874	
280				
281		E: SEPARATELY METERED SPACE HEAT	16,525,698.8	
282				
283		F: REACTIVE DEMAND ADJUSTMENT	-	
284				
285	**ANNUAL ENERGY/REVENUE**		57,801,681	
286				

	A	B	C	D
1	**MO LARGE POWER**			
2	**SECONDARY VOLTAGE - LPGSS**			
3				
4	**SUMMER**			
5				
6			**BILLING UNITS**	
7				
8		A: CUSTOMER CHARGE		
9			128.0	
10			-	
11			-	
12			128	
13				
14		B: FACILITIES CHARGE	310,779.3	
15				
16		C: DEMAND CHARGE		
17		First 2443 kw	212,847.2	
18		Next 2443 kw	57,728.0	
19		Next 2443 kw	21,524.8	
20		Over 7329 kw	2,789.0	
21			294,889	
22		D: ENERGY CHARGE		
23		0-180 hrs use per month	53,009,956.2	
24		181-360 hrs use per month	52,752,997.2	
25		361+ hrs use per month	56,474,267.1	
26			162,237,220	
27				
28		E: REACTIVE DEMAND ADJUSTMENT	2,887.9	
29				
30				
31	**WINTER**			
32				
33			**BILLING UNITS**	
34				
35		A: CUSTOMER CHARGE		
36			256.0	
37			-	
38			-	
39			256	
40				
41		B: FACILITIES CHARGE	607,769.7	
42				
43		C: DEMAND CHARGE		
44		First 2443 kw	391,822.8	
45		Next 2443 kw	87,652.0	
46		Next 2443 kw	19,750.2	
47		Over 7329 kw	-	
48			499,225	
49		D: ENERGY CHARGE		
50		0-180 hrs use per month	89,180,017.5	
51		181-360 hrs use per month	87,826,192.8	
52		361+ hrs use per month	88,751,506.9	
53			265,757,717	
54				
55		E: REACTIVE DEMAND ADJUSTMENT	4,941.1	
56				
57				
58	**ANNUAL**		427,994,938	
59				

A	B	C	D
MO LARGE POWER			
PRIMARY VOLTAGE - LPGSP			
SUMMER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
		132.0	
		-	
		-	
		132	
	B: FACILITIES CHARGE	645,460.4	
	C: DEMAND CHARGE		
	First 2500 kw	292,606.3	
	Next 2500 kw	144,789.6	
	Next 2500 kw	65,209.7	
	Over 7500 kw	93,895.4	
		596,501	
	D: ENERGY CHARGE		
	0-180 hrs use per month	107,147,703.8	
	181-360 hrs use per month	105,170,304.9	
	361+ hrs use per month	99,734,015.8	
		312,052,024	312,052,024
	E: REACTIVE DEMAND ADJUSTMENT	51,062	
WINTER			
		BILLING UNITS	
	A: CUSTOMER CHARGE		
		264.0	
		-	
		-	
		264	
	B: FACILITIES CHARGE	1,260,896.6	
	C: DEMAND CHARGE		
	First 2500 kw	551,967.7	
	Next 2500 kw	226,692.4	
	Next 2500 kw	106,754.3	
	Over 7500 kw	120,362.6	
		1,005,777	
	D: ENERGY CHARGE		
	0-180 hrs use per month	180,445,945.6	
	181-360 hrs use per month	176,951,504.4	
	361+ hrs use per month	168,506,312.1	
		525,903,762	
	E: REACTIVE DEMAND ADJUSTMENT	94,584	
ANNUAL		837,955,787	

MO LARGE POWER
SUBSTATION VOLTAGE - LPGSSS

SUMMER

	BILLING UNITS
A: CUSTOMER CHARGE	
	12.0
	-
	-
	12
B: FACILITIES CHARGE	268,248.7
C: DEMAND CHARGE	
First 2530 kw	30,565.4
Next 2530 kw	28,681.9
Next 2530 kw	20,250.5
Over 7590 kw	181,247.2
	260,745
D: ENERGY CHARGE	
0-180 hrs use per month	46,915,718.0
181-360 hrs use per month	46,915,718.0
361+ hrs use per month	51,336,467.0
	145,167,903
E: REACTIVE DEMAND ADJUSTMENT	24,065

WINTER

	BILLING UNITS
A: CUSTOMER CHARGE	
	24.0
	-
	-
	24
B: FACILITIES CHARGE	532,431.3
C: DEMAND CHARGE	
First 2530 kw	60,514.6
Next 2530 kw	52,476.1
Next 2530 kw	40,469.5
Over 7590 kw	314,947.8
	468,408
D: ENERGY CHARGE	
0-180 hrs use per month	84,281,992.9
181-360 hrs use per month	84,281,992.9
361+ hrs use per month	93,697,249.5
	262,261,235
E: REACTIVE DEMAND ADJUSTMENT	31,009

ANNUAL 407,429,138

MO LARGE POWER
TRANSMISSION VOLTAGE - LPGSTR

SUMMER

		BILLING UNITS
	A: CUSTOMER CHARGE	
		8.0
		-
		-
		8
	B: FACILITIES CHARGE	-
	C: DEMAND CHARGE	
	First 2553 kw	14,828.0
	Next 2553 kw	10,217.3
	Next 2553 kw	10,217.3
	Over 7659 kw	33,027.1
		68,290
	D: ENERGY CHARGE	
	0-180 hrs use per month	12,292,161.4
	181-360 hrs use per month	11,794,642.9
	361+ hrs use per month	8,125,952.0
		32,212,756
	E: REACTIVE DEMAND ADJUSTMENT	6,217

WINTER

		BILLING UNITS
	A: CUSTOMER CHARGE	
		16.0
		-
		-
		16
	B: FACILITIES CHARGE	-
	C: DEMAND CHARGE	
	First 2553 kw	36,383.0
	Next 2553 kw	20,754.7
	Next 2553 kw	20,418.7
	Over 7659 kw	53,041.9
		130,598
	D: ENERGY CHARGE	
	0-180 hrs use per month	23,293,238.6
	181-360 hrs use per month	21,529,677.1
	361+ hrs use per month	15,876,328.0
		60,699,244
	E: REACTIVE DEMAND ADJUSTMENT	3,189
ANNUAL		92,912,000

	A	B	C	D
237	**MO LARGE POWER**			
238	**TRANSMISSION VOLTAGE - OFF PEAK - LPSTRO**			
239				
240	**SUMMER**			
241				
242			**BILLING UNITS**	
243				
244		A: CUSTOMER CHARGE		
245			8.0	
246			-	
247			-	
248			8	
249				
250		B: FACILITIES CHARGE	-	
251				
252		C: DEMAND CHARGE		
253		First 2553 kw	20,470.5	
254		Next 2553 kw	14,442.6	
255		Next 2553 kw	10,253.2	
256		Over 7659 kw	42,295.9	
257			87,462	
258		D: ENERGY CHARGE		
259		0-180 hrs use per month	15,707,254.3	
260		181-360 hrs use per month	15,707,254.3	
261		361+ hrs use per month	24,275,365.1	
262			55,689,874	
263				
264		E: REACTIVE DEMAND ADJUSTMENT	4,061	
265				
266	**WINTER**			
267				
268			**BILLING UNITS**	
269				
270		A: CUSTOMER CHARGE		
271			16.0	
272			-	
273			-	
274			16	
275				
276		B: FACILITIES CHARGE	-	
277				
278		C: DEMAND CHARGE		
279		First 2553 kw	40,801.5	
280		Next 2553 kw	25,645.4	
281		Next 2553 kw	17,829.8	
282		Over 7659 kw	60,235.1	
283			144,512	
284		D: ENERGY CHARGE		
285		0-180 hrs use per month	25,954,885.7	
286		181-360 hrs use per month	25,954,885.7	
287		361+ hrs use per month	34,252,258.8	
288			86,162,030	
289				
290		E: REACTIVE DEMAND ADJUSTMENT	4,622	
291				
292	**ANNUAL**		141,851,904	
293				
294				
295				

	A	B	C	D
296	**MO LARGE POWER**			
297	**PRIMARY VOLTAGE, OFF PEAK - LPGSPO**			
298				
299	**SUMMER**			
300				
301			**BILLING UNITS**	
302		A: CUSTOMER CHARGE		
303			40.0	
304			-	
305			-	
306			40	
307				
308		B: FACILITIES CHARGE	207,906.1	
309				
310		C: DEMAND CHARGE		
311		First 2500 kw	85,608.4	
312		Next 2500 kw	45,310.5	
313		Next 2500 kw	27,382.0	
314		Over 7500 kw	26,637.7	
315			184,939	
316		D: ENERGY CHARGE		
317		0-180 hrs use per month	33,109,665.2	
318		181-360 hrs use per month	32,766,510.6	
319		361+ hrs use per month	33,152,951.6	
320			99,029,127	
321				
322		E: REACTIVE DEMAND ADJUSTMENT	21,355	
323				
324	**WINTER**			
325				
326			**BILLING UNITS**	
327		A: CUSTOMER CHARGE		
328			80.0	
329			-	
330			-	
331			80	
332				
333		B: FACILITIES CHARGE	417,672.9	
334				
335		C: DEMAND CHARGE		
336		First 2500 kw	163,462.6	
337		Next 2500 kw	68,912.5	
338		Next 2500 kw	34,615.0	
339		Over 7500 kw	46,109.3	
340			313,099	
341		D: ENERGY CHARGE		
342		0-180 hrs use per month	56,294,422.0	
343		181-360 hrs use per month	54,290,447.6	
344		361+ hrs use per month	58,452,136.9	
345			169,037,006	
346				
347		E: REACTIVE DEMAND ADJUSTMENT	37,222	
348				
349	**ANNUAL**		268,066,134	
350				

KCP&L Greater Missouri Operations Company MPS Rate District
MPSC Case No. ER-2012-0175
Reconciliation of Issues Decided by the Commission
Revenue Requirement Impact

ROE		Change Revenue Requirement
9.7% Per Order	26,245,608	
9.1% Per OPC	19,306,624	(6,938,984)
9.5% Per FEA	23,925,403	(2,320,205)
9.78% Per Staff	27,151,550	905,942
10.3% Per Company	33,161,098	6,915,490
Cost of Debt		
6.187% Per Staff	24,731,890	(1,513,718)
Capital Structure		
Eliminate OCI per Company	26,618,548	372,940
Debt/Equity Cost Structure per OPC, MECG	22,905,919	(3,339,689)
Crossroads		
Plant, Reserve, Depr. Exp & Def Inc Tax Exp per Company	33,280,352	7,034,744
ADIT per Company	25,790,244	(455,364)
ADIT per Industrials	25,092,688	(1,152,920)
Transmission Exp. per Company	30,072,364	3,826,756
Rate Design - Winter, Space Heating, & All-Electric		
Space Heating Elimination per MGE	26,243,348	(2,260)
Customer Charge per Company, Staff	26,241,704	(3,904)

KCP&L Greater Missouri Operations Company MPS Rate District
MPSC Case No. ER-2012-0175

ROE
Issue: **9.1% Per OPC**
Value: **(6,938,984)**

	Impact Amount	Impact Percent
Residential	(3,793,337)	-1.22%
Small General Service	(991,959)	-1.24%
Large General Service	(917,423)	-1.23%
Large Power	(1,110,463)	-1.22%
Thermal Service	(6,081)	-1.22%
Lighting	(119,721)	-1.26%
Total	(6,938,984)	-1.23%

ROE
Issue: **9.5% Per FEA**
Value: **(2,320,205)**

	Impact Amount	Impact Percent
Residential	(1,268,387)	-0.41%
Small General Service	(331,684)	-0.41%
Large General Service	(306,761)	-0.41%
Large Power	(371,308)	-0.41%
Thermal Service	(2,033)	-0.41%
Lighting	(40,032)	-0.42%
Total	(2,320,205)	-0.41%

ROE
Issue: **9.78% Per Staff**
Value: **905,942**

	Impact Amount	Impact Percent
Residential	495,252	0.16%
Small General Service	129,509	0.16%
Large General Service	119,777	0.16%
Large Power	144,980	0.16%
Thermal Service	794	0.16%
Lighting	15,631	0.16%
Total	905,942	0.16%

ROE
Issue: **10.3% Per Company**
Value: **6,915,490**

	Impact Amount	Impact Percent
Residential	3,780,494	1.22%
Small General Service	988,601	1.23%

Large General Service	914,317	1.23%
Large Power	1,106,703	1.22%
Thermal Service	6,060	1.22%
Lighting	119,316	1.25%
Total	6,915,490	1.22%

Cost of Debt
Issue: **6.187% Per Staff**
Value: **(1,513,718)**

	Impact	
	Amount	Percent
Residential	(827,505)	-0.27%
Small General Service	(216,393)	-0.27%
Large General Service	(200,133)	-0.27%
Large Power	(242,244)	-0.27%
Thermal Service	(1,326)	-0.27%
Lighting	(26,117)	-0.27%
Total	(1,513,718)	-0.27%

Capital Structure
Issue: **Eliminate OCI per Company**
Value: **372,940**

	Impact	
	Amount	Percent
Residential	203,875	0.07%
Small General Service	53,313	0.07%
Large General Service	49,307	0.07%
Large Power	59,682	0.07%
Thermal Service	327	0.07%
Lighting	6,434	0.07%
Total	372,940	0.07%

Capital Structure
Issue: **Debt/Equity Cost Structure per OPC, MECG**
Value: **(3,339,689)**

	Impact	
	Amount	Percent
Residential	(1,825,709)	-0.59%
Small General Service	(477,424)	-0.59%
Large General Service	(441,550)	-0.59%
Large Power	(534,459)	-0.59%
Thermal Service	(2,927)	-0.59%
Lighting	(57,621)	-0.61%
Total	(3,339,689)	-0.59%

Crossroads
Issue: **Plant, Reserve, Depr. Exp & Def Inc Tax Exp per Company**
Value: **7,034,744**

Impact

	Amount	Percent
Residential	3,845,686	1.24%
Small General Service	1,005,649	1.25%
Large General Service	930,084	1.25%
Large Power	1,125,787	1.24%
Thermal Service	6,164	1.24%
Lighting	121,374	1.28%
Total	7,034,744	1.24%

Crossroads
Issue: **ADIT per Company**
Value: **(455,364)**

	Impact	
	Amount	Percent
Residential	(248,934)	-0.08%
Small General Service	(65,096)	-0.08%
Large General Service	(60,205)	-0.08%
Large Power	(72,873)	-0.08%
Thermal Service	(399)	-0.08%
Lighting	(7,857)	-0.08%
Total	(455,364)	-0.08%

Crossroads
Issue: **ADIT per Industrials**
Value: **(1,152,920)**

	Impact	
	Amount	Percent
Residential	(630,267)	-0.20%
Small General Service	(164,815)	-0.21%
Large General Service	(152,431)	-0.20%
Large Power	(184,505)	-0.20%
Thermal Service	(1,010)	-0.20%
Lighting	(19,892)	-0.21%
Total	(1,152,920)	-0.20%

Crossroads
Issue: **Transmission Exp. per Company**
Value: **3,826,756**

	Impact	
	Amount	Percent
Residential	2,091,974	0.67%
Small General Service	547,052	0.68%
Large General Service	505,946	0.68%
Large Power	612,405	0.67%
Thermal Service	3,353	0.68%
Lighting	66,025	0.69%
Total	3,826,756	0.68%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Space Heating Elimination per MGE**

Value: **(2,260)**

	Impact Amount	Impact Percent
RATE MO860, MO865 (GENERAL USE)	(3,684,048)	-2.09%
RATE MO870, MO866 (GENERAL USE WITH SPACE HEAT & NET METERING)	3,728,456	3.16%
RATE MO815 (GENERAL USE OTHER)	(46,668)	-10.31%
RATE MO600 (GENERAL USE TIME OF DAY)	-	0.00%
Total	(2,260)	0.00%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Customer Charge per Company, Staff**
Value: **(3,904)**

	Impact Amount	Impact Percent
RATE MO860, MO865 (GENERAL USE)	19,627	0.01%
RATE MO870, MO866 (GENERAL USE WITH SPACE HEAT & NET METERING)	(27,355)	-0.03%
RATE MO815 (GENERAL USE OTHER)	3,824	0.84%
RATE MO600 (GENERAL USE TIME OF DAY)	-	0.00%
Total	(3,904)	0.00%

	A	B	C	D	E
1	**MO RESIDENTIAL - MPS**				
2	**RATE MO860, MO865 (GENERAL USE)**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		CUSTOMER COUNT		546,932.7	
9					
10		KWH:			
11		0 - 600		297,722,086.0	
12		601 - 1000		109,231,451.2	
13		1000+		268,812,084.4	
14				675,765,621.6	
15					
16					
17					
18					
19					
20					
21					
22					
23	**WINTER**				
24					
25				**BILLING UNITS**	
26					
27		CUSTOMER COUNT		1,101,255.6	
28					
29		KWH:			
30		0 - 600		534,021,336.2	
31		601 - 1000		177,355,836.0	
32		1000+		160,233,333.1	
33				871,610,505.3	
34					
35					
36					
37					
38					
39					
40					
41					
42					
43	**ANNUAL**			1,547,376,127	
44					
45					

	A	B	C	D	E
46	**MO RESIDENTIAL - MPS**				
47	**RATE MO870, MO866 (GENERAL USE WITH SPACE HEAT & NET METERING)**				
49	**SUMMER**				
51				**BILLING UNITS**	
53		CUSTOMER COUNT		303,978.0	
55		KWH:			
56		0 - 600		168,516,179.3	
57		601 - 1000		61,964,908.7	
58		1000+		180,198,767.9	
59				410,679,855.9	
68	**WINTER**				
70				**BILLING UNITS**	
72		CUSTOMER COUNT		603,709.6	
74		KWH:			
75		0 - 600		337,153,987.0	
76		601 - 1000		167,474,212.1	
77		1000+		317,255,677.8	
78				821,883,876.8	
88	**ANNUAL**			1,232,563,733	

	A	B	C	D	E
91	**MO RESIDENTIAL - MPS**				
92	**RATE MO815 (GENERAL USE OTHER)**				
93					
94	**SUMMER**				
95					
96				**BILLING UNITS**	
97					
98		CUSTOMER COUNT		3,423.4	
99					
100		KWH:			
101		All KWH		700,410.3	
102				700,410.3	
103					
104					
105					
106					
107					
108					
109					
110					
111	**WINTER**				
112					
113				**BILLING UNITS**	
114					
115		CUSTOMER COUNT		6,560.5	
116					
117		KWH:			
118		All KWH		1,817,359.7	
119				1,817,359.7	
120					
121					
122					
123					
124					
125					
126					
127					
128	**ANNUAL**			2,517,770	
129					
130					

	A	B	C	D	E
131	**MO RESIDENTIAL - MPS**				
132	**RATE MO600 (GENERAL USE TIME OF DAY)**				
133					
134	**SUMMER**				
135					
136				**BILLING UNITS**	
137					
138		CUSTOMER COUNT		-	
139					
140		KWH:			
141		On-Peak		-	
142		Shoulder		-	
143		Off-Peak		-	
144				-	
145					
146					
147					
148					
149					
150					
151	**WINTER**				
152					
153				**BILLING UNITS**	
154					
155		CUSTOMER COUNT		-	
156					
157		KWH:			
158		On-Peak		-	
159		Off-Peak		-	
160				-	
161					
162					
163					
164					
165					
166					
167	**ANNUAL**			-	

	A	B	C	D	E
1	**MO SMALL GENERAL - MPS**				
2	**Non-Demand Service MO710, MO867**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		A: CUSTOMER COUNT		35,440.7	
9					
10		B: ENERGY CHARGE			
11		Energy Charge		26,204,554.5	
12					
13				26,204,554.5	
14					
15					
16					
17					
18					
19					
20					
21					
22					
23	**WINTER**				
24					
25				**BILLING UNITS**	
26					
27		A: CUSTOMER COUNT		70,148.4	
28					
29		B: ENERGY CHARGE			
30		Base Energy		29,840,831.3	
31		Seasonal Energy		17,673,510.3	
32				47,514,341.6	
33					
34					
35					
36					
37					
38					
39					
40					
41					
42	**ANNUAL**			73,718,896	
43					

	A	B	C	D	E
44	**MO SMALL GENERAL - MPS**				
45	**Temporary Non-Demand Service MO728**				
46					
47	**SUMMER**				
48					
49				**BILLING UNITS**	
50					
51		A: CUSTOMER COUNT		1,721.7	
52					
53		B: ENERGY CHARGE		390,744.6	
54					
55					
56					
57					
58					
59					
60					
61					
62	**WINTER**				
63					
64				**BILLING UNITS**	
65					
66		A: CUSTOMER COUNT		3,084.9	
67					
68		B: ENERGY CHARGE		842,145.1	
69					
70					
71					
72					
73					
74					
75					
76					
77	**ANNUAL**			1,232,890	
78					
79					

	A	B	C	D	E
80	**MO SMALL GENERAL - MPS**				
81	**Demand Service at Secondary Voltage MO711, MO868**				
82					
83	**SUMMER**				
84					
85				**BILLING UNITS**	
86		A: CUSTOMER CHARGE		76,594.7	
87					
88		B: DEMAND CHARGE			
89		Billing Demand		1,110,544.8	
90					
91				1,110,544.8	
92					
93		C: ENERGY CHARGE			
94		First 180 hours of use		165,641,628.6	
95		Next 180 hours of use		74,784,146.3	
96		Over 360 hours of use		19,082,645.5	
97				259,508,420.4	
98					
99					
100	**WINTER**				
101					
102				**BILLING UNITS**	
103					
104		A: CUSTOMER CHARGE		154,079.3	
105					
106		B: DEMAND CHARGE			
107		Base Billing Demand		1,365,953.5	
108		Seasonal Billing Demand		-	
109				1,365,953.5	
110					
111		C: BASE ENERGY CHARGE			
112		First 180 hours of use		204,807,575.5	
113		Next 180 hours of use		90,678,502.6	
114		Over 360 hours of use		23,801,976.7	
115				319,288,054.9	
116					
117		D: SEASONAL ENERGY CHARGE			
118		Seasonal Energy Charge		112,686,374.7	
119					
120					
121				112,686,374.7	
122					
123	**ANNUAL**			691,482,850	
124					
125					

MO SMALL GENERAL SERVICE - MPS
Demand Service at Primary Voltage MO716 (frozen)

SUMMER

	BILLING UNITS
A: CUSTOMER CHARGE	12.0
B: DEMAND CHARGE	
Billing Demand	329.0
	329.0
C: ENERGY CHARGE	
First 180 hours of use	57,806.8
Next 180 hours of use	36,832.9
Over 360 hours of use	31,681.7
	126,321.4

WINTER

	BILLING UNITS
A: CUSTOMER CHARGE	24.0
B: DEMAND CHARGE	
Base Billing Demand	364.8
Seasonal Billing Demand	-
	364.8
C: BASE ENERGY CHARGE	
First 180 hours of use	63,866.7
Next 180 hours of use	49,716.3
Over 360 hours of use	48,359.5
	161,942.6
D: SEASONAL ENERGY CHARGE	
Seasonal Energy Charge	75,413.3
	75,413.3

ANNUAL	363,677

	A	B	C	D	E
1	**MO LARGE GENERAL - MPS**				
2	**Secondary Voltage MO720, MO722**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		A: CUSTOMER CHARGE		5,699.7	
9					
10		B: DEMAND CHARGE			
11		Billing Demand		1,054,111.3	
12					
13				1,054,111.3	
14					
15		C: ENERGY CHARGE			
16		First 180 hours of use		176,100,148.2	
17		Next 180 hours of use		120,356,917.9	
18		Over 360 hours of use		46,683,934.8	
19				343,141,001.0	
25					
26					
27	**WINTER**				
28					
29				**BILLING UNITS**	
30					
31		A: CUSTOMER CHARGE		11,407.5	
32					
33		B: DEMAND CHARGE			
34		Base Billing Demand		1,486,438.1	
35		Seasonal Billing Demand		-	
36				1,486,438.1	
37					
38		C: BASE ENERGY CHARGE			
39		First 180 hours of use		235,744,875.5	
40		Next 180 hours of use		161,383,335.5	
41		Over 360 hours of use		53,519,215.5	
42				450,647,426.5	
43					
44		D: SEASONAL ENERGY CHARGE			
45		Seasonal Energy Charge		130,324,847.1	
46					
47					
48				130,324,847	
49					
50					
51	**ANNUAL**			924,113,275	
52					
53					

	A	B	C	D	E
54	**MO LARGE GENERAL SERVICE - MPS**				
55	**Primary Voltage MO725**				
56					
57	**SUMMER**				
58					
59				**BILLING UNITS**	
60					
61		A: CUSTOMER CHARGE		37.8	
62					
63		B: DEMAND CHARGE			
64		Billing Demand		18,374.4	
65					
66				18,374.4	
67					
68		C: ENERGY CHARGE			
69		First 180 hours of use		2,755,904.3	
70		Next 180 hours of use		1,935,850.9	
71		Over 360 hours of use		1,324,473.4	
72				6,016,228.6	
73					
79					
80					
81	**WINTER**				
82					
83				**BILLING UNITS**	
84					
85		A: CUSTOMER CHARGE		73.0	
86					
87		B: DEMAND CHARGE			
88		Base Billing Demand		10,461.4	
89		Seasonal Billing Demand		-	
90				10,461.4	
91					
92		C: BASE ENERGY CHARGE			
93		First 180 hours of use		1,632,149.1	
94		Next 180 hours of use		1,319,744.8	
95		Over 360 hours of use		491,738.3	
96				3,443,632.2	
97					
98		D: SEASONAL ENERGY CHARGE			
99		Seasonal Energy Charge		10,410,518.3	
100					
101					
102				10,410,518.3	
103					
104					
105	**ANNUAL**			19,870,379	

	A	B	C	D	E
1	**MO LARGE POWER - MPS**				
2	**Secondary Voltage MO730, MO732 (SECONDARY & NET METERING)**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		A: CUSTOMER CHARGE		554.1	
9					
10		B: DEMAND CHARGE			
11		Billing Demand		533,623.6	
12					
13				533,623.6	
14					
15		C: ENERGY CHARGE			
16		First 180 hours of use		95,473,973.0	
17		Next 180 hours of use		91,329,700.6	
18		Over 360 hours of use		65,271,257.7	
19				252,074,931.3	
20					
26					
27		E: REACTIVE DEMAND ADJUSTMENT		40,606.1	
28					
29					
30	**WINTER**				
31					
32				**BILLING UNITS**	
33					
34		A: CUSTOMER CHARGE		1,101.9	
35					
36		B: DEMAND CHARGE			
37		Base Billing Demand		748,497.3	
38		Seasonal Billing Demand		-	
39				748,497.3	
40					
41		C: BASE ENERGY CHARGE			
42		First 180 hours of use		129,366,702.1	
43		Next 180 hours of use		120,331,851.5	
44		Over 360 hours of use		83,492,062.0	
45				333,190,615.5	
46					
47		D: SEASONAL ENERGY CHARGE			
48				92,300,398.5	
51				92,300,398.5	
52					
53		E: REACTIVE DEMAND ADJUSTMENT		48,110.7	
54					
55					
56	**ANNUAL**			677,565,945	
57					
58					

	A	B	C	D	E
59	**MO LARGE GENERAL SERVICE - MPS**				
60	**Primary Voltage MO735**				
61					
62	**SUMMER**				
63					
64				**BILLING UNITS**	
65					
66		A: CUSTOMER CHARGE		165.2	
67					
68		B: DEMAND CHARGE			
69		Billing Demand		522,194.3	
70					
71				522,194.3	
72					
73		C: ENERGY CHARGE			
74		First 180 hours of use		93,215,976.3	
75		Next 180 hours of use		91,568,280.1	
76		Over 360 hours of use		83,628,421.9	
77				268,412,678.4	
78					
84					
85		E: REACTIVE DEMAND ADJUSTMENT		62,036.2	
86					
87					
88	**WINTER**				
89					
90				**BILLING UNITS**	
91					
92		A: CUSTOMER CHARGE		326.8	
93					
94		B: DEMAND CHARGE			
95		Base Billing Demand		680,545.5	
96		Seasonal Billing Demand		-	
97				680,545.5	
98					
99		C: BASE ENERGY CHARGE			
100		First 180 hours of use		118,814,098.2	
101		Next 180 hours of use		114,197,574.4	
102		Over 360 hours of use		113,653,016.3	
103				346,664,688.8	
104					
105		D: SEASONAL ENERGY CHARGE			
106				110,879,253.0	
109				110,879,253.0	
110					
111		E: REACTIVE DEMAND ADJUSTMENT		94,600.1	
112					
113	**ANNUAL**			725,956,620	
114					

	A	B	C	D	E
115	**MO LARGE POWER - MPS**				
116	**RTP Secondary MO731**				
117					
118	**SUMMER**				
119					
120				**BILLING UNITS**	
121					
122		A: CUSTOMER CHARGE		-	
123					
124		B: ENERGY CHARGE			
125		CBL		-	
126		RTP		-	
127				-	
128					
129		C: REACTIVE DEMAND ADJUSTMENT		-	
130					
131					
132					
133	**WINTER**				
134					
135				**BILLING UNITS**	
136					
137		A: CUSTOMER CHARGE		-	
138					
139		B: ENERGY CHARGE			
140		CBL			
141		RTP			
142				-	
143					
144		C: REACTIVE DEMAND ADJUSTMENT		-	
145					
146					
147					
148					
149	**ANNUAL**			-	
150					
151					

	A	B	C	D	E
152	**MO LARGE POWER - MPS**				
153	**RTP MO737**				
154					
155	**SUMMER**				
156					
157				**BILLING UNITS**	
158					
159		A: CUSTOMER CHARGE		-	
160					
161		B: ENERGY CHARGE			
162		CBL			
163		RTP			
164				6,179,684.7	
165					
166		C: REACTIVE DEMAND ADJUSTMENT		-	
167					
168					
169					
170	**WINTER**				
171					
172				**BILLING UNITS**	
173					
174		A: CUSTOMER CHARGE		-	
175					
176		B: ENERGY CHARGE			
177		CBL			
178		RTP			
179				12,359,369.3	
180					
181		C: REACTIVE DEMAND ADJUSTMENT		-	
182					
183					
184					
185	**ANNUAL**			18,539,054	
186					

	A	B	C	D	E	F
1	**MO THERMAL ENERGY STORAGE SERVICE - MPS**					
2	**RATES MO650**					
3						
4	**SUMMER**					
5						
6				**BILLING UNITS**		
7		A: CUSTOMER CHARGE				
8		All		4.0		
9				4.0		
10						
11						
12		B: DEMAND CHARGE				
13		All KW		6,178.0		
14				6,178.0		
15						
16		C: ENERGY CHARGE				
17		Peak		789,904.0		
18		Shoulder		1,592,707.0		
19		Off-Peak		989,032.0		
20				3,371,643.0		
21						
22						
23						
24	**WINTER**					
25						
26				**BILLING UNITS**		
27		A: CUSTOMER CHARGE				
28		All		8.0		
29				8.0		
30						
31		B: DEMAND CHARGE				
32		All KW		8,964.0		
33				8,964.0		
34						
35		C: ENERGY CHARGE				
36		Peak		2,204,173.0		
37		Off-Peak		1,828,425.0		
38				4,032,598.0		
39						
40						
41	**ANNUAL**			7,404,241		
42						

	A	B	C	D	E
1	**MO GENERAL TIME OF DAY - MPS**				
2	**Rate MO610**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		A: CUSTOMER COUNT		-	
9				-	
10					
11					
12		C: ENERGY CHARGE			
13		On-Peak		-	
14		Shoulder		-	
15		Off-Peak		-	
16				-	
17					
18					
19					
20					
21					
22					
23					
24	**WINTER**				
25					
26				**BILLING UNITS**	
27					
28		A: CUSTOMER COUNT		-	
29				-	
30					
31		C: ENERGY CHARGE			
32		ON-PEAK		-	
33		OFF-PEAK		-	
34				-	
35					
36					
37					
38					
39					
40					
41					
42					
43	**ANNUAL**			-	
44					
45					

	A	B	C	D	E
46	**MO GENERAL TIME OF DAY - MPS**				
47	**Rate MO620**				
48					
49	**SUMMER**				
50					
51				**BILLING UNITS**	
52					
53		A: CUSTOMER COUNT		-	
54				-	
55					
56					
57		B: DEMAND CHARGE			
58				-	
59				-	
60					
61		C: ENERGY CHARGE			
62		On-Peak		-	
63		Shoulder		-	
64		Off-Peak		-	
65				-	
66					
67					
68					
69	**WINTER**				
70					
71				**BILLING UNITS**	
72					
73		A: CUSTOMER COUNT		-	
74				-	
75					
76		B: DEMAND CHARGE			
77				-	
78				-	
79					
80		C: ENERGY CHARGE			
81		ON-PEAK		-	
82		OFF-PEAK		-	
83				-	
84					
85					
86					
87					
88	**ANNUAL**			-	
89					
90					

	A	B	C	D	E
91	**MO GENERAL TIME OF DAY - MPS**				
92	**Rate MO630**				
93					
94	**SUMMER**				
95					
96				**BILLING UNITS**	
97					
98		A: CUSTOMER COUNT		-	
99				-	
100					
101					
102		B: DEMAND CHARGE			
103				-	
104				-	
105					
106		C: ENERGY CHARGE			
107		On-Peak		-	
108		Shoulder		-	
109		Off-Peak		-	
110				-	
111					
112					
113					
114	**WINTER**				
115					
116				**BILLING UNITS**	
117					
118		A: CUSTOMER COUNT		-	
119				-	
120					
121		B: DEMAND CHARGE			
122				-	
123				-	
124					
125		C: ENERGY CHARGE			
126		ON-PEAK		-	
127		OFF-PEAK		-	
128				-	
129					
130					
131					
132					
133	**ANNUAL**			-	
134					
135					

	A	B	C	D	E
136	**MO GENERAL TIME OF DAY - MPS**				
137	**Rate MO640**				
138					
139	**SUMMER**				
140					
141				**BILLING UNITS**	
142					
143		A: CUSTOMER COUNT		-	
144				-	
145					
146					
147		B: DEMAND CHARGE			
148				-	
149				-	
150					
151		C: ENERGY CHARGE			
152		On-Peak		-	
153		Shoulder		-	
154		Off-Peak		-	
155				-	
156					
157					
158					
159	**WINTER**				
160					
161				**BILLING UNITS**	
162					
163		A: CUSTOMER COUNT		-	
164				-	
165					
166		B: DEMAND CHARGE			
167				-	
168				-	
169					
170		C: ENERGY CHARGE			
171		ON-PEAK		-	
172		OFF-PEAK		-	
173				-	
174					
175					
176					
177					
178	**ANNUAL**			-	
179					

KCP&L Greater Missouri Operations Company L&P Rate District
MPSC Case No. ER-2012-0175
Reconciliation of Issues Decided by the Commission
Revenue Requirement Impact

ROE		Change Revenue Requirement
9.7% Per Order	21,696,437	
9.1% Per OPC	19,317,167	(2,379,270)
9.5% Per FEA	20,904,660	(791,777)
9.78% Per Staff	22,005,592	309,155
10.3% Per Company	24,056,366	2,359,929

Cost of Debt		
6.187% Per Staff	21,179,877	(516,560)

Capital Structure		
Eliminate OCI per Company	21,823,705	127,268
Debt/Equity Cost Structure per OPC, MECG	20,556,760	(1,139,677)

Rate Design - Winter, Space Heating, & All-Electric		
Space Heating Elimination per MGE	21,695,654	(783)
Winter Heating Blocks per Company	21,691,355	(5,082)
Customer Charge per Company, Staff	21,694,796	(1,641)

ROE
Issue: **9.1% Per OPC**
Value: **(2,379,270)**

	Impact Amount	Percent
Residential	(1,017,515)	-1.23%
Small General Service	(181,762)	-1.25%
Large General Service	(414,477)	-1.24%
Large Power	(710,437)	-1.24%
Metered Lighting	(1,690)	-1.27%
Lighting	(53,390)	-1.27%
Total	(2,379,270)	-1.24%

ROE
Issue: **9.5% Per FEA**
Value: **(791,777)**

	Impact Amount	Percent
Residential	(338,610)	-0.41%
Small General Service	(60,487)	-0.42%
Large General Service	(137,930)	-0.41%
Large Power	(236,420)	-0.41%
Metered Lighting	(562)	-0.42%
Lighting	(17,767)	-0.42%
Total	(791,777)	-0.41%

ROE
Issue: **9.78% Per Staff**
Value: **309,155**

	Impact Amount	Percent
Residential	132,213	0.16%
Small General Service	23,618	0.16%
Large General Service	53,856	0.16%
Large Power	92,312	0.16%
Metered Lighting	220	0.17%
Lighting	6,937	0.17%
Total	309,155	0.16%

ROE
Issue: **10.3% Per Company**
Value: **2,359,929**

	Impact Amount	Percent
Residential	1,009,244	1.22%
Small General Service	180,284	1.24%
Large General Service	411,108	1.23%
Large Power	704,662	1.23%

Metered Lighting	1,676	1.26%
Lighting	52,956	1.26%
Total	2,359,929	1.23%

Cost of Debt
Issue: **6.187% Per Staff**
Value: **(516,560)**

	Impact	
	Amount	Percent
Residential	(220,911)	-0.27%
Small General Service	(39,462)	-0.27%
Large General Service	(89,987)	-0.27%
Large Power	(154,242)	-0.27%
Metered Lighting	(367)	-0.28%
Lighting	(11,591)	-0.28%
Total	(516,560)	-0.27%

Capital Structure
Issue: **Eliminate OCI per Company**
Value: **127,268**

	Impact	
	Amount	Percent
Residential	54,427	0.07%
Small General Service	9,722	0.07%
Large General Service	22,171	0.07%
Large Power	38,002	0.07%
Metered Lighting	90	0.07%
Lighting	2,856	0.07%
Total	127,268	0.07%

Capital Structure
Issue: **Debt/Equity Cost Structure per OPC, MECG**
Value: **(1,139,677)**

	Impact	
	Amount	Percent
Residential	(487,393)	-0.59%
Small General Service	(87,064)	-0.60%
Large General Service	(198,536)	-0.60%
Large Power	(340,301)	-0.59%
Metered Lighting	(809)	-0.61%
Lighting	(25,574)	-0.61%
Total	(1,139,677)	-0.59%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Space Heating Elimination per MGE**
Value: **(783)**

	Impact	
	Amount	Percent
Rate MO910, MO911, MO965(GENERAL USE & NET METERING)	(2,898,774)	-7.67%
RATE MO920, MO921, MO966 (GENERAL USE WITH SPACE HEAT - ONE METER &	2,920,789	8.60%
RATE MO915 (GENERAL USE OTHER)	(24,975)	-2.36%

RATE MO922 (GENERAL USE - SEPARATE SPACE HEAT METER)	2,177	9.24%
Total	(783)	0.00%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Winter Heating Blocks per Company**
Value: **(5,082)**

	Impact	
	Amount	Percent
Rate MO910, MO911, MO965(GENERAL USE & NET METERING)	636,211	1.57%
RATE MO920, MO921, MO966 (GENERAL USE WITH SPACE HEAT - ONE METER &	(655,265)	-2.11%
RATE MO915 (GENERAL USE OTHER)	14,327	1.32%
RATE MO922 (GENERAL USE - SEPARATE SPACE HEAT METER)	(355)	-1.66%
Total	(5,082)	-0.01%

Rate Design - Winter, Space Heating, & All-Electric
Issue: **Customer Charge per Company, Staff**
Value: **(1,641)**

	Impact	
	Amount	Percent
Rate MO910, MO911, MO965(GENERAL USE & NET METERING)	30,981	0.08%
RATE MO920, MO921, MO966 (GENERAL USE WITH SPACE HEAT - ONE METER &	(47,920)	-0.15%
RATE MO915 (GENERAL USE OTHER)	15,234	1.41%
RATE MO922 (GENERAL USE - SEPARATE SPACE HEAT METER)	63	0.30%
Total	(1,641)	0.00%

	A	B	C	D	E	F
1	**MO RESIDENTIAL - L&P**					
2	**Rate MO910, MO911, MO965(GENERAL USE & NET METERING)**					
3						
4	**SUMMER**					
5						
6				**BILLING UNITS**		
7						
8		CUSTOMER COUNT		141230.9		
9						
10		KWH:				
11		0 - 650		152941923.1		
12		650 +		0.0		
13				152,941,923		
14						
15						
16						
17						
18						
19						
20						
21						
22	**WINTER**					
23						
24				**BILLING UNITS**		
25						
26		CUSTOMER COUNT		283647.1		
27						
28		KWH:				
29		0 - 650		140535971.7		
30		650 +		88925133.9		
31				229,461,106		
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	**ANNUAL**			382,403,029		
42						
43						

	A	B	C	D	E	F
44	**MO RESIDENTIAL - L&P**					
45	**RATE MO920, MO921, MO966**					
46	**(GENERAL USE WITH SPACE HEAT - ONE METER & NET METERING)**					
47	**SUMMER**					
48						
49				**BILLING UNITS**		
50						
51		CUSTOMER COUNT		81604.4		
52						
53		KWH:				
54		0 - 1000		99744288.7		
55		1000+		0.0		
56				99,744,289		
57						
58						
59						
60						
61						
62						
63						
64						
65	**WINTER**					
66						
67				**BILLING UNITS**		
68						
69		CUSTOMER COUNT		162220.0		
70						
71		KWH:				
72		0 - 1000		139033719.3		
73		1000+		143440691.4		
74				282,474,411		
75						
76						
77						
78						
79						
80						
81						
82						
83						
84	**ANNUAL**			382,218,699		
85						
86						

	A	B	C	D	E	F
87	**MO RESIDENTIAL - L&P**					
88	**RATE MO915 (GENERAL USE OTHER)**					
89						
90	**SUMMER**					
91						
92				**BILLING UNITS**		
93						
94		CUSTOMER COUNT		8095.6		
95						
96		KWH:				
97		ALL KWH		1350599.0		
98				1,350,599		
99						
100						
101						
102						
103						
104						
105						
106						
107	**WINTER**					
108						
109				**BILLING UNITS**		
110						
111		CUSTOMER COUNT		16174.5		
112						
113		KWH:				
114		ALL KWH		5272670.2		
115				5,272,670		
116						
117						
118						
119						
120						
121						
122						
123						
124						
125	**ANNUAL**			6,623,269		
126						

	A	B	C	D	E	F
127	**MO RESIDENTIAL - L&P**					
128	**RATE MO922 (GENERAL USE - SEPARATE SPACE HEAT METER)**					
129						
130	**SUMMER**					
131						
132				**BILLING UNITS**		
133						
134		CUSTOMER COUNT		167.1		
135						
136		KWH:				
137		ALL KWH		73847.8		
138				73,848		
139						
140		FAC				
141						
142						
143						
144						
145						
146						
147	**WINTER**					
148						
149				**BILLING UNITS**		
150						
151		CUSTOMER COUNT		335.1		
152						
153		KWH:				
154		ALL KWH		173282.6		
155				173,283		
156						
157						
158						
159						
160						
161						
162						
163						
164						
165	**ANNUAL**			247,130		

	A	B	C	D	E
1	**MO SMALL GENERAL - L&P**				
2	**Limited Demand Service MO930, MO967**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		A: CUSTOMER COUNT		14,755.5	
9					
10		B: ENERGY CHARGE			
11		All Kwh		10,016,572.9	
12				10,016,572.9	
13					
14					
15					
16					
17					
18					
19					
20					
21	**WINTER**				
22					
23				**BILLING UNITS**	
24					
25		A: CUSTOMER COUNT		29,583.1	
26					
27		B: ENERGY CHARGE			
28		All Kwh		19,883,181.7	
29				19,883,181.7	
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	**ANNUAL**			29,899,755	
40					

	A	B	C	D	E
41	**MO SMALL GENERAL - L&P**				
42	**General Use MO931, MO968**				
43					
44	**SUMMER**				
45					
46				**BILLING UNITS**	
47					
48		A: CUSTOMER COUNT		-	
49					
50		B: FACILITIES KW CHARGE:			
51		For the first ten (10) kw per bill		92,646.9	
52		For all over ten (10) per each kw		100,754.6	
53				193,402	
54					
55		B: ENERGY CHARGE			
56		0-150		16,408,883.5	
57		over 150		9,910,096.8	
58				26,318,980.3	
59					
60					
61					
62					
63					
64					
65					
66					
67	**WINTER**				
68					
69				**BILLING UNITS**	
70					
71		A: CUSTOMER COUNT		-	
72					
73		B: FACILITIES KW CHARGE:			
74		For the first ten (10) kw per bill		185,346.8	
75		For all over ten (10) per each kw		200,287.0	
76				385,633.9	
77					
78		B: ENERGY CHARGE			
79		0-150		31,284,885.9	
80		over 150		18,576,570.5	
81				49,861,456.4	
82					
83					
84					
85					
86					
87					
88					
89					
90					
91	**ANNUAL**			76,180,437	
92					

	A	B	C	D	E
93	**MO SMALL GENERAL - L&P**				
94	**Short Term Service MO928**				
95					
96	**SUMMER**				
97					
98				**BILLING UNITS**	
99					
100		A: CUSTOMER COUNT		227.2	
101					
102		B: ENERGY CHARGE			
103		All Kwh		180,817.7	
104				180,817.7	
105					
106					
107					
108					
109					
110					
111					
112					
113	**WINTER**				
114					
115				**BILLING UNITS**	
116					
117		A: CUSTOMER COUNT		469.1	
118					
119		B: ENERGY CHARGE			
120		All Kwh		372,129.1	
121				372,129.1	
122					
123					
124					
125					
126					
127					
128					
129					
130					
131	**ANNUAL**			552,947	
132					
133					

	A	B	C	D	E
134	**MO SMALL GENERAL SERVICE - L&P**				
135	**Space Heat/Water Heat Separate Meter MO941 (Frozen)**				
136					
137	**SUMMER**				
138					
139				**BILLING UNITS**	
140					
141		A: CUSTOMER COUNT		258.5	
142					
143		B: ENERGY CHARGE			
144		All Kwh		373,937.5	
145				373,937.5	
146					
147					
148					
149					
150					
151					
152					
153					
154	**WINTER**				
155					
156				**BILLING UNITS**	
157					
158		A: CUSTOMER COUNT		522.5	
159					
160		B: ENERGY CHARGE			
161		All Kwh		1,147,306.6	
162				1,147,306.6	
163					
164					
165					
166					
167					
168					
169					
170					
171					
172	**ANNUAL**			1,521,244	

	A	B	C	D	E
1	**MO LARGE GENERAL SERVICE - L&P**				
2	**ALL RATES MO938, MO939, MO940**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7		A: FACILITIES CHARGE			
8		First 40 KW		183,087.2	
9		All KW > 40		356,245.6	
10				539,332.8	
11					
12		B: DEMAND CHARGE			
13		All KW		437,855.3	
14				437,855.3	
15					
16		C: ENERGY CHARGE			
17		For the first 200 KWH Per actual KW		77,763,996.1	
18		For all KWH over 200 per Actual KW		54,417,953.5	
19				132,181,949.5	
20					
21					
22					
23					
24					
25					
26					
27					
28	**WINTER**				
29					
30				**BILLING UNITS**	
31		A: FACILITIES CHARGE			
32		First 40 KW		366,050.8	
33		All KW > 40		706,495.8	
34				1,072,546.7	
35					
36		B: DEMAND CHARGE			
37		Base Billing Demand		769,750.3	
38		Seasonal Billing Demand		60,106.4	
39				829,856.7	
40					
41		C: ENERGY CHARGE			
42		For the first 200 KWH Per actual KW		143,700,580.5	
43		For all KWH over 200 per Actual KW		99,138,257.0	
44				242,838,837.5	
45					
46					
47					
48	**ANNUAL**			377,900,378	
49					

	A	B	C	D	E
1	**MO LARGE POWER SERVICE - L&P**				
2	**ALL RATES MO944, MO945, MO946, MO947**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7		A: FACALITIES CHARGE			
8		First 500 KW		152,954.2	
9		All KW > 500		497,565.5	
10				650,519.7	
11					
12		B: DEMAND CHARGE			
13		All KW		593,579.8	
14				593,579.8	
15					
16		C: ENERGY CHARGE			
17		for each "On - Peak" KWH		120,795,754.6	
18		for each "Off - Peak" KWH		181,396,349.5	
19				302,192,104.1	
20					
21					
22	**WINTER**				
23					
24				**BILLING UNITS**	
25		A: FACALITIES CHARGE			
26		First 500 KW		303,045.8	
27		All KW > 500		982,290.3	
28				1,285,336.1	
29					
30		B: DEMAND CHARGE			
31		Each KW less </= prev Summer Peak KW		1,085,391.4	
32		Eack KW > prev Summer Peak KW		9,911.0	
33				1,095,302.4	
34					
35		C: ENERGY CHARGE			
36		for each "On - Peak" KWH		265,345,893.4	
37		for each "Off - Peak" KWH		287,211,343.5	
38				552,557,236.9	
39					
40					
41	**ANNUAL**			854,749,341	
42					

	A	B	C	D	E
1	**MO METERED LIGHTING - L&P**				
2	**RATE MO971**				
3					
4	**SUMMER**				
5					
6				**BILLING UNITS**	
7					
8		SERVICE CHARGE		181.5	
9					
10		KWH:			
11		All		201,159.7	
12				201,159.7	
13					
14					
15					
16					
17					
18					
19					
20					
21	**WINTER**				
22					
23				**BILLING UNITS**	
24					
25		SERVICE CHARGE		365.0	
26					
27		KWH:			
28		All		192,049.3	
29				192,049.3	
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	**ANNUAL**			393,209	
40					
41					

	A	B	C	D	E
42	**MO METERED LIGHTING - L&P**				
43	**RATE MO972**				
44					
45	**SUMMER**				
46					
47				**BILLING UNITS**	
48					
49		SECONDARY METER BASE		98.3	
50		OTHER METER		18.6	
51					
52		KWH:			
53		All		212,498.9	
54				212,498.9	
55					
56					
57					
58					
59					
60					
61					
62					
63	**WINTER**				
64					
65				**BILLING UNITS**	
66					
67		SECONDARY METER BASE		188.2	
68		OTHER METER		29.4	
69					
70		KWH:			
71		All		608,299.1	
72				608,299.1	
73					
74					
75					
76					
77					
78					
79					
80					
81					
82	**ANNUAL**			820,798	
83					
84					

	A	B	C	D	E
85	**MO METERED LIGHTING - L&P**				
86	**RATE MO973**				
87					
88	**SUMMER**				
89					
90				**BILLING UNITS**	
91					
92		CUSTOMER COUNT		261.1	
93					
94		KWH:			
95		All		102,090.3	
96				102,090.3	
97					
98					
99					
100					
101					
102					
103					
104					
105	**WINTER**				
106					
107				**BILLING UNITS**	
108					
109		CUSTOMER COUNT		464.7	
110					
111		KWH:			
112		All		230,171.7	
113				230,172	
114					
115					
116					
117					
118					
119					
120					
121					
122	**ANNUAL**			332,262	
123					