BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L	)	
Greater Missouri Operations Company for	)	**<u>File No. ER-2010-0356</u>**
Approval to Make Certain Changes in its	)	
Charges for Electric Service.	)	

REPORT AND ORDER

Issue Date: **May 4, 2011**

Effective Date: **May 14, 2011**

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REPORT AND ORDER

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Regulatory Law Judges: **Nancy Dippell, Deputy Chief, Regulatory Law Judge**
Ronald D. Pridgin, Senior Regulatory Law Judge

In Memoriam

The Commissioners and all the employees at the Commission express their deepest sympathy to Curtis Blanc's family, friends, and colleagues for his untimely death which occurred on February 16, 2011, while he was in Jefferson City in order to attend the scheduled hearings for these cases.

Procedural History

On June 4, 2010, KCP&L Greater Missouri Operations Company (GMO) submitted to the Commission proposed tariff sheets, effective for service on and after May 4, 2011, that are intended to implement a general rate increase for electrical service provided in its Missouri service area. GMO's proposed tariffs would increase its Missouri jurisdictional revenues by approximately $75.8 million and $22.1 million for its MPS and L&P service territories, respectively. According to GMO, this represented a 14.43% rate increase for MPS based on current Missouri jurisdictional revenue, including fuel adjustment clause revenue of approximately $525 million. It also represents a 13.87% increase for L&P based on current Missouri jurisdictional revenues, including a fuel adjustment clause revenue of approximately $159 million. The Commission issued an Order and Notice on June 11, in which it gave interested parties until July 1 to request intervention.[1] GMO voluntarily extended the tariff effective date until June 4, 2011.

The Commission received timely intervention requests from: Dogwood Energy, LLC; the City of Kansas City, Missouri; Ag Processing, Inc., a Cooperative; the Sedalia

[1] Calendar dates refer to 2010 unless otherwise noted.

Industrial Energy Users Association (SIEUA); Union Electric Company, d/b/a Ameren Missouri; the City of Lee's Summit, Missouri; the Hospital Intervenors,[2] Missouri Gas Energy, a Division of Southern Union Company; Robert Wagner; the Federal Executive Agencies; the American Association of Retired Persons (AARP), the Consumers Council of Missouri, The Empire District Electric Company; Missouri Retailers Association; the Missouri Department of Natural Resources; and the City of St. Joseph, Missouri. The Commission granted these requests.

The test year is the 12 months ending December 31, 2009, updated for known and measureable changes through June 30, 2010, and trued-up through December 31, 2010.[3] Portions of the hearings in this case were held simultaneously with the hearings in ER-2010-0355 for Kansas City Power & Light Company (KCP&L). Common issues were also addressed in the Report and Order in ER-2010-0355 but will be repeated in this order. The Commission held local public hearings in Nevada, St. Joseph, Kansas City, Riverside, Lee's Summit, and Carrollton. The evidentiary hearing went from January 18 through February 4, 2011, February 14 through February 17, 2011, and the true-up hearing was held on March 3-4, 2011.

Non-Unanimous Stipulations and Agreements

The Commission received seven Non-unanimous Stipulations and Agreements from February 2 to March 23, 2011. With regard to GMO, those stipulations resolved: depreciation, amortizations, an Economic Relief Pilot Program, employee severance

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[2] Consisting of Lee's Summit Medical Center, Liberty Hospital, Research Belton Hospital, Saint Luke's East – Lee's Summit, St. Mary's Medical Center, Saint Luke's Northland Hospital – Smithville Campus, and North Kansas City Hospital.

[3] Ex. GMO 210, p. 8.

cost, Supplemental Executive Retirement Pension cost, advertising cost, bad debt expense, cash working capital imputed accounts receivable program, Proposition C expenses, call center reporting, tracker use for Iatan operation and maintenance expenses, transmission expense and revenue tracker, outdoor lighting, class cost of service and rate design, MGE rate design issue, pensions and other post-employment benefits, and Iatan common costs.

No parties objected to the nonunanimous stipulation and agreements. Therefore, as permitted by Commission Rule 4 CSR 240-2.115, the Commission will treat the stipulations as if they were unanimous. The Commission finds the above-referenced stipulations reasonable and approves them.

General Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision. When making findings of fact based upon witness testimony, the Commission will assign the appropriate weight to the testimony of each witness based upon their qualifications, expertise and credibility with regard to the attested to subject matter.[4]

1. Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations Company ("GMO") are both wholly owned by Great Plains Energy, Inc. ("GPE"). Their service areas in Missouri are shown on Schedule 2 to the direct testimony of Cary G. Featherstone.[5]

2. Collectively, KCP&L and GMO operate and present themselves to the public under the brand and service mark "KCP&L." The workforce for GMO consists of KCP&L employees; GMO has no employees of its own. Before it was acquired by GPE, GMO was named Aquila, Inc., and before that, Utilicorp United, Inc.[6]

3. KCP&L serves approximately 509,000 customers, of which about 450,000 are residential customers, about 57,000 are commercial customers and the remaining about 2,000 are industrial, municipal and other utility customers. To serve these customers, KCP&L owns and operates 571 MW of nuclear generating capacity and, with Iatan 2, about 2,774 MW of coal capacity,[7] and with Spearville 2, 148 MW of wind capacity, 829 MW of natural gas-fired combustion turbine capacity, and 302 MW of oil-fired combustion turbine capacity. It also purchases power.[8]

4. GMO has approximately 312,000 customers, of which about 273,500 are residential customers, about 38,000 are commercial customers and the remaining about

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[4] Witness credibility is solely within the discretion of the Commission, who is free to believe all, some, or none of a witness' testimony. *State ex. rel. Missouri Gas Energy v. Public Service Comm'n*, 186 S.W.3d 376, 389 (Mo. App. 2005).

[5] Ex. KCP&L 215.

[6] Ex. KCP&L 210, p. 1; Ex. KCP&L 215, pp. 3-4 & 12; Ex. GMO 210, p. 1; Ex. GMO 215, pp. 3, 11.

[7] Iatan 2 ownership is 54.7% of 850 MW, equaling 465 MW.

[8] Ex. KCP&L 210, pp. 1-2; Ex. KCP&L 215, p. 43.

500 customers are industrial, municipal and other utility customers. To serve these customers, GMO owns, with Iatan 2, 2,128 MW of generating capacity, of which 1,045 MW is coal capacity,[9] 1,019 MW is natural gas-fired combustion turbine capacity, and 64 MW is oil-fired combustion turbine capacity. Like KCP&L, it also purchases power.[10]

5. These two rate cases started on June 4, 2010, when KCP&L and GMO filed applications and proposed tariff changes to implement general electric rate increases. The cases are File Nos. ER-2010-0355 and ER-2010-0356, respectively. KCP&L stated its application was designed to recover an additional $92.1 million per year in rate revenues, a 13.8% increase.[11] By its true-up direct case filed on February 22, 2011, KCP&L stated its revenue deficiency is $55.8 million.[12] In its true-up direct case filed that same day, Staff recommended an annual increase in revenue requirement of $9.6 million.[13]

6. GMO's service area is divided into two separate rate districts referred to as MPS and L&P. The MPS rate district includes parts of Kansas City, Lee's Summit, Sedalia, Warrensburg and surrounding areas. The L&P rate district is in and about St. Joseph, Missouri. GMO stated its application was designed to recover an additional $75.8 million per year in rate revenues from its customers in its MPS rate district, a 14.4% increase, and an additional $22.1 million per year in rate revenues from its

[9] Iatan 2 ownership is 18% of 850 MW, equaling 153 MW.
[10] Ex. GMO 210, pp. 1-2; Ex. GMO 215, p. 34.
[11] Ex. KCP&L 215, pp. 10-11; Ex. GMO 215, pp. 3-4.
[12] Ex. KCP&L 114, p. 1; Ex. KCP&L 117, p. 1 (but per the Staff's reconciliation, KCP&L's requested revenue increase is $66.5 million).
[13] Ex. KCP&L 304, p. 4.

customers in its L&P rate district a 13.9% increase.[14] By its true-up direct case filed on February 22, 2011, GMO stated its revenue deficiency for MPS is $65.2 million and its revenue deficiency for L&P is $23.2 million.[15] In its true-up direct case filed that same day, Staff recommended an annual increase in revenue requirement for MPS of $4.6 million and an increase of $16.6 million for L&P.[16]

General Conclusions of Law

Conclusions of Law Regarding Jurisdiction

1. GMO is an electric utility and a public utility subject to Commission jurisdiction.[17] The Commission has authority to regulate the rates GMO may charge for electricity.[18]

2. The Commission is authorized to value the property of electric utilities in Missouri.[19] Necessarily, that includes property and other assets proposed for inclusion in rate base. In determining value, "the commission may consider all facts which in its judgment have any bearing upon a proper determination of the question . . . ."[20] The courts have held that this statute means that the Commission's determination of the

[14] Ex. GMO 210, p. 7; Ex. GMO 215, pp. 3, 10; Ex. KCP&L 215, Sch. 2.
[15] Ex. GMO 58, p. 1.
[16] Ex. KCP&L 304, p. 4.
[17] Section 386.020(15), (42), RSMo 2010 (all statutory cites to RSMo 2010 unless otherwise indicated).
[18] Section 393.140(11).
[19] Section 393.230.1, RSMo.
[20] Section 393.270.4, RSMo.

proper rate must be based on consideration of all relevant factors.[21] Relevant factors include questions raised by stakeholders about the prudency and necessity of utility construction decisions and expenditures.

3. In making its determination, the Commission may adopt or reject any or all of any witnesses' testimony.[22] Testimony need not be refuted or controverted to be disbelieved by the Commission.[23] The Commission determines what weight to accord to the evidence adduced.[24] "It may disregard evidence which in its judgment is not credible, even though there is no countervailing evidence to dispute or contradict it."[25] The Commission may evaluate the expert testimony presented to it and choose between the various experts.[26]

4. The Staff of the Commission is represented by the Commission's Staff Counsel, who has been delegated the duties of the Commission's General Counsel, an employee of the Commission authorized by statute to "represent and appear for the commission in all actions and proceedings involving this or any other law [involving the commission.]"[27] The Public Counsel is appointed by the Director of the Missouri Department of Economic Development and is authorized to "represent and protect the interests of the public in any proceeding before or appeal from the public service

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[21] *State ex rel. Missouri Water Co. v. Public Service Commission***,** 308 S.W.2d 704, 719 (Mo. 1957); *State ex rel. Midwest Gas Users' Association v. Public Service Commission***,** 976 S.W.2d 470, 479 (Mo. App., W.D. 1998); *State ex rel. Office of Public Counsel v. Public Service Commission of Missouri,* 858 S.W.2d 806 (Mo. App., W.D. 1993).

[22] *State ex rel. Associated Natural Gas Co. v. Public Service Commission***,** 706 S.W.2d 870, 880 (Mo. App., W.D. 1985).

[23] *State ex rel. Rice v. Public Service Commission***,** 359 Mo. 109, 116, 220 S.W.2d 61, 65 (banc 1949).

[24] *Id.*

[25] *Id.*

[26] *Associated Natural Gas***,** *supra,* 706 S.W.2d at 882.

[27] Section 386.071.

commission[.]"[28] The remaining parties include governmental entities, other electric utilities, and consumers.

Burden of Proof

5. "At any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or proposed increased rate is just and reasonable shall be upon the . . . electrical corporation . . . and the commission shall give to the hearing and decision of such questions preference over all other questions pending before it and decide the same as speedily as possible."[29]

Ratemaking Standards and Practices

6. The Commission is vested with the state's police power to set "just and reasonable" rates for public utility services,[30] subject to judicial review of the question of reasonableness.[31] A "just and reasonable" rate is one that is fair to both the utility and its customers;[32] it is no more than is sufficient to "keep public utility plants in proper

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[28] Sections 386.700 and 386.710.

[29] Section 393.150.2.

[30] Section 393.130, in pertinent part, requires a utility's charges to be "just and reasonable" and not in excess of charges allowed by law or by order of the commission. Section 393.140 authorizes the Commission to determine "just and reasonable" rates.

[31] *St. ex rel. City of Harrisonville v. Pub. Serv. Comm'n of Missouri*, 291 Mo. 432, 236 S.W. 852 (Mo. banc. 1922); *City of Fulton v. Pub. Serv. Comm'n*, 275 Mo. 67, 204 S.W. 386 (Mo. banc. 1918), *error dis'd,* 251 U.S. 546, 40 S.Ct. 342, 64 L.Ed. 408; *City of St. Louis v. Pub. Serv. Comm'n of Missouri*, 276 Mo. 509, 207 S.W. 799 (1919); *Kansas City v. Pub. Serv. Comm'n of Missouri*, 276 Mo. 539, 210 S.W. 381 (1919), *error dis'd,* 250 U.S. 652, 40 S.Ct. 54, 63 L.Ed. 1190; *Lightfoot v. City of Springfield*, 361 Mo. 659, 236 S.W.2d 348 (1951).

[32] *St. ex rel. Valley Sewage Co. v. Pub. Serv. Comm'n*, 515 S.W.2d 845 (Mo. App. 1974).

repair for effective public service, [and] . . . to insure to the investors a reasonable return upon funds invested."[33] In 1925, the Missouri Supreme Court stated:[34]

> The enactment of the Public Service Act marked a new era in the history of public utilities. Its purpose is to require the general public not only to pay rates which will keep public utility plants in proper repair for effective public service, but further to insure to the investors a reasonable return upon funds invested. The police power of the state demands as much. We can never have efficient service, unless there is a reasonable guaranty of fair returns for capital invested. * * * These instrumentalities are a part of the very life blood of the state, and of its people, and a fair administration of the act is mandatory. When we say "fair," we mean fair to the public, and fair to the investors.

7. The Commission's guiding purpose in setting rates is to protect the consumer against the natural monopoly of the public utility, generally the sole provider of a public necessity.[35] "[T]he dominant thought and purpose of the policy is the protection of the public . . [and] the protection given the utility is merely incidental."[36] However, the Commission must also afford the utility an opportunity to recover a reasonable return on the assets it has devoted to the public service.[37] "There can be no argument but that the Company and its stockholders have a constitutional right to a fair and reasonable return upon their investment."[38]

8. The Commission has exclusive jurisdiction to establish public utility rates,[39] and the rates it sets have the force and effect of law.[40] A public utility has no

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[33] *St. ex rel. Washington University et al. v. Pub. Serv. Comm'n*, 308 Mo. 328, 344-45, 272 S.W. 971, 973 (Mo. banc 1925).

[34] *Id.*

[35] *May Dep't Stores Co. v. Union Elec. Light & Power Co*., 341 Mo. 299, 107 S.W.2d 41, 48 (Mo. App. 1937).

[36] *St. ex rel. Crown Coach Co. v. Pub. Serv. Comm'n*, 179 S.W.2d 123, 126 (1944).

[37] *St. ex rel. Utility Consumers Council, Inc. v. Pub. Serv. Comm'n*, 585 S.W.2d 41, 49 (Mo. banc 1979).

[38] *St. ex rel. Missouri Public Service Co. v. Fraas*, 627 S.W.2d 882, 886 (Mo. App. 1981).

[39] *May Dep't Stores*, *supra,*107 S.W.2d at 57.

[40] *Utility Consumers Council*, *supra*, 585 S.W.2d at 49.

right to fix its own rates and cannot charge or collect rates that have not been approved by the Commission;[41] neither can a public utility change its rates without first seeking authority from the Commission.[42] A public utility may submit rate schedules or "tariffs," and thereby suggest to the Commission rates and classifications which it believes are just and reasonable, but the final decision is the Commission's.[43] Thus, "[r]atemaking is a balancing process."[44]

9. Ratemaking involves two successive processes: first, the determination of the "revenue requirement," that is, the amount of revenue the utility must receive to pay the costs of producing the utility service while yielding a reasonable rate of return to the investors.[45]

10. The second process is rate design, that is, the construction of tariffs that will collect the necessary revenue requirement from the ratepayers. Revenue requirement is usually established based upon a historical test year that focuses on four factors: (1) the rate of return the utility has an opportunity to earn; (2) the rate base upon which a return may be earned; (3) the depreciation costs of plant and equipment; and (4) allowable operating expenses. The calculation of revenue requirement from these four factors is expressed in the following formula:

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[41] *Id.*
[42] *Deaconess Manor Ass'n v. Pub. Serv. Comm'n*, 994 S.W.2d 602, 610 (Mo. App. 1999).
[43] *May Dep't Stores*, *supra,*107 S.W.2d at 50.
[44] *St. ex rel. Union Elec. Co. v. Pub. Serv. Comm'n*, 765 S.W.2d 618, 622 (Mo. App. 1988).
[45] *St. ex rel. Capital City Water Co. v. Missouri Pub. Serv. Comm'n*, 850 S.W.2d 903, 916 n. 1 (Mo. App. 1993).

$$RR = C + (V - D) R$$

where: RR = Revenue Requirement;
C = Prudent Operating Costs, including Depreciation Expense and Taxes;
V = Gross Value of Utility Plant in Service;
D = Accumulated Depreciation; and
R = Overall Rate of Return or Weighted Cost of Capital.

11. The return on the rate base is calculated by applying a rate of return, that is, the weighted cost of capital, to the original cost of the assets dedicated to public service less accumulated depreciation.[46]

12. The Public Service Commission Act vests the Commission with the necessary authority to perform these functions. The Commission can prescribe uniform methods of accounting for utilities, and can examine a utility's books and records and, after hearing, can determine the accounting treatment of any particular transaction.[47] In this way, the Commission can determine the utility's prudent operating costs. The Commission can value the property of electric utilities operating in Missouri that is used and useful to determine the rate base.[48] Finally, the Commission can set depreciation rates and adjust a utility's depreciation reserve from time-to-time as may be necessary.[49]

13. The Revenue Requirement is the sum of two components: first, the utility's prudent operating expenses, and second, an amount calculated by multiplying the value of the utility's depreciated assets by a rate of return. For any utility, its fair rate

[46] *See St. ex rel. Union Elec. Co.*, 765 S.W.2d at 622.
[47] Section 393.140.
[48] Section 393.230. Section 393.135 expressly prohibits the inclusion in electric rates of costs pertaining to property that is not "used and useful."
[49] Section 393.240.

of return is simply its composite cost of capital. The composite cost of capital is the sum of the weighted cost of each component of the utility's capital structure. The weighted cost of each capital component is calculated by multiplying its cost by a percentage expressing its proportion in the capital structure. Where possible, the cost used is the "embedded" or historical cost; however, in the case of Common Equity, the cost used is its estimated cost.

14. Because the parties have no dispute regarding rate design or depreciation, the Commission will resolve the issues below generally in the following order: rate base, rate of return, and expenses.

<u>The Issues</u>

Being unable to agree on how to phrase many issues, GMO (jointly with KCPL) and Staff submitted separate lists of issues for determination by the Commission. The Commission phrases and resolves the issues herein. The issues listed at the beginning of each section may be phrased differently than those presented and may not be inclusive of all issues decided. The Commission has previously decided the issues common to KCPL and GMO[50] and those decisions will be repeated here as they apply to GMO.

[50] File No. ER-2010-0355, *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Continue the Implementation of Its Regulatory Plan*, Report and Order (issued April 12, 2011); and Order of Clarification (issued April 19, 2011).

I. Rate Base

A. Iatan

Should the Iatan 1 and 2 Rate Base Additions be included in rate base in this proceeding?

Should the Commission presume that the costs of those additions were prudently incurred until a serious doubt has been raised as to the prudence of the investment by a party to this proceeding?

Has a serious doubt regarding the prudence of the Iatan 1 and 2 additions been raised?

Should the Company's conduct be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight?

Did KCP&L prudently manage the Iatan 1 and 2 projects?

Is the December 2006 Control Budget Estimate the definitive estimate?

Should the costs of the Iatan 1 and 2 projects be measured against the Control Budget Estimate?

Should the Iatan 1, 2 and common regulatory assets be included in rate base, as well as the annualized amortization expense?

Findings of Fact – Iatan

7. On August 5, 2005, the Commission approved the Stipulation and Agreement in File No. EO-2005-0329 ("Regulatory Plan"). Under the Regulatory Plan, KCP&L[51] has embarked upon a series of infrastructure and customer enhancement projects valued at over $2.64 billion. Section III.B.4. of the Regulatory Plan which identifies the required level of KCP&L's reporting of the Comprehensive Energy Plan

[51] Because KCP&L is the managing entity for each of the co-owners of the Iatan Project, KCP&L is the entity referred to in the Iatan section of this Report and Order.

("CEP") Projects states: Section III.B.4. of the Regulatory Plan identifies the required level of KCP&L's reporting of the CEP Projects:

> KCPL shall provide status updates on these infrastructure commitments to the Staff, Public Counsel, MDNR and all other interested Signatory Parties on a quarterly basis. Such reports will explain why these investment decisions are in the public interest. In addition, KCPL will continue to work with the Staff, Public Counsel and all other interested Signatory Parties in its long-term resource planning efforts to ensure that its current plans and commitments are consistent with the future needs of its customers and the energy needs of the State of Missouri.[52]

8. KCP&L complied with this requirement by providing nineteen (19) written Quarterly Reports to Staff, OPC, and any other interested party, starting with the first quarter of 2006 through the third quarter of 2010.[53]

9. KCP&L recently submitted the 20th Quarterly Report on February 15, 2011. Those Quarterly Reports discuss the status of the Regulatory Plan infrastructure investments, and other specific significant issues existing during the reporting period. KCP&L also met regularly with Staff, OPC, and representatives of the Signatory Parties to discuss the contents of the Quarterly Reports, as well as provide more current information if available at the time of the meeting.[54]

10. In addition, the Missouri Retailers Association's ("MRA") consultant, Walter Drabinski and his colleagues from Vantage Consulting, also received the Quarterly Reports and attended the Quarterly Meetings that KCP&L held with the Kansas Corporation Commission ("KCC") Staff.[55]

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[52] *See* Commission File No. EO-2005-0329, Stipulation and Agreement at III.B.4, p. 46.
[53] Tr. 1160-65; Ex. KCP&L 69, pp. 19-24; Ex. KCP&L 70, pp. 2, 4, 8, 38,
[54] Tr. 1160-64.
[55] Tr. 1586-1590.

11. Mr. Drabinski visited the Iatan Project site and met with KCP&L on seventeen (17) separate occasions.[56]

12. KCP&L responded to Mr. Drabinski's data requests and provided to Mr. Drabinski unfettered access to KCP&L's project personnel, its consultants, and the Iatan Project documentation. Mr. Drabinski agreed that the information provided was sufficient for him to perform a prudence analysis.[57]

13. The Quarterly Reports identified the Iatan Project's risks as they were known throughout the Project and KCP&L's strategy for mitigating those risks. In the first quarter 2007 Quarterly Report, KCP&L began including a specific section entitled "Identification of Project Risks" to describe the key issues recognized by management regarding Iatan Unit 2.[58]

14. The risks identified and tracked in the Quarterly Reports were primarily the same risks that KCP&L identified in the analysis of contingency that was performed in establishing the Control Budget Estimate in December 2006.[59]

15. Mr. Giles describes in his testimony the risks and mitigation plans that KCP&L was tracking throughout the life of the Project.[60]

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[56] Id.
[57] Tr. 1586, ln. 22, to 1590, ln. 25.
[58] *See* Ex. KCP&L 71 ; *see also* Ex. KCP&L 24, pp. 18-26; Ex. KCP&L 25, pp. 37-41.
[59] *See* Ex. KCP&L 24, pp. 20-24; Ex. KCP&L-25, pp. 39- 41.
[60] *See* Ex. KCP&L 24, pp. 20-24.

Cost Control System and Unidentified Cost Overruns

16. Both Staff and KCP&L agreed that for purposes of the Stipulation, the Control Budget Estimate would serve as the baseline budget for the Projects and the Definitive Estimate from which the Iatan Units 1 and 2 Projects would be measured.[61]

17. KCP&L's witnesses Mr. Archibald, Mr. Meyer and Mr. Nielsen, as well as the Missouri Retailer's Association witness Mr. Walter Drabinski and Staff's Mr. Elliott, each showed that the Cost Control System that KCP&L developed for the Iatan Project allowed for any interested party to fully examine the costs incurred on the Iatan Project.[62]

18. KCP&L's Cost Control System provided the guidance needed to establish the Iatan Project's Cost Portfolio, which it uses for day-to-day tracking and management of Iatan Project's costs.[63]

19. The Cost Control System contains all the information needed to both identify and explain each of the overruns to the Control Budget Estimate that occurred on the Iatan Project.[64]

20. Mr. Meyer placed KCP&L's Cost Control System in the top quartile of those he has seen, and believes this system has allowed for the effective cost management of the Iatan Projects.[65]

21. KCP&L's cost control system is consistent with industry best practices.[66]

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[61] Tr. 1095-97; 2643-44.

[62] *See* Ex. KCP&L 25, pp. 20-22; Ex. KCP&L 4, pp. 3-4; Tr. pp. 2176-77.

[63] Ex. KCP&L 205, p. 10; *see also* Ex. KCP&L 44, pp. 3, 10-12, p. 30, and Schs. DFM2010-17 to DFM2010-24; Ex. KCP&L 46, p. 26.

[64] *See* Ex. KCP&L 205, pp. 11-13.

[65] *See* Ex. KCP&L 44, pp. 3, 7-8.

[66] *See* Ex. KCP&L-43, p. 5, ln. 10; Ex. KCP&L 46, pp. 249-250.

22. KCP&L's cost control system allows any interested party to this matter to track every dollar that KCP&L spent on the Iatan Project, regardless of whether the costs were anticipated in the Control Budget Estimate or constitute a cost overrun to the Control Budget Estimate: "Our system allows you to track through every dollar that's spent from cradle to grave and understand where it was spent and wherever the overrun occurred."[67]

23. KCP&L complied with the requirements in the Regulatory Plan regarding the cost control process for construction expenditures. Section III.B.1.q. of the Regulatory Plan requires that KCP&L do the following:

> KCPL must develop and have a cost control system in place that identifies and explains any cost overruns above the definitive estimate during the construction period of the Iatan 2 project, the wind generation projects and the environmental investments.

24. KCP&L has complied with these requirements. First, KCP&L developed a comprehensive Cost Control System which provides key guidance to each of the CEP Projects governed by the Stipulation.[68]

25. KCP&L's Cost Control System, which was transmitted to the Staff and the other Signatory Parties' representatives on July 10, 2006, "describes the governance considerations, management procedures, and cost control protocols for the CEP Projects" including the Iatan Project.[69]

26. On July 11, 2006, KCP&L representatives met with members of the Staff and the other interested parties. Staff raised no concerns at that meeting.[70]

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[67] Tr. 2176-77.
[68] Ex. KCP&L 38, at Sch. SJ2010-1.
[69] Ex. KCP&L 25, p. 21, ln. 9-11; KCP&L 38, Sch. SJ2010-1, p. 3.
[70] Ex. KCP&L 25, p. 22.

27. Additionally, KCP&L has conducted quarterly meetings addressing Project issues, including costs, and provided Staff with thousands of well-organized and detailed documents describing and explaining the cost overruns and has explained to Staff multiple times in face-to-face meetings how the documents can be used to identify and explain the overruns on the Iatan Project.[71]

28. Further, the Cost Control System states that the Iatan Project's cost performance would be measured against the Project's Control Budget Estimate (i.e., Definitive Estimate), and to do so, the Iatan Project's Control Budget "will identify the original budget amount (whether contracted or estimated) for each line item of the Project's costs and will track those budget line items against the following:

- Costs committed to date
- Actual paid to date
- Change orders to date
- Expected at completion, based on current forecasts."[72]

29. The Cost Control System also identified the Iatan Project's actual and budgeted costs would be tracked in comparison to Iatan Unit 1 Project's and Iatan Unit 2 Project's respective Definitive Estimates. The Cost Control System states that:

> The Project Team will develop a Definitive Estimate for each Project that will provide an analytical baseline for evaluating Project costs. The estimate will establish anticipated costs for individual work activities and all procurements. The Definitive Estimate will be used to establish each Project's Control Budget.[73]

[71] Ex. KCP&L 25, p. 4, ln. 4-7.
[72] Ex. KCP&L 38, Sch. SJ2010-1, p. 17.
[73] *Id.* at Sch. SJ2010-1, at p. 8.

30. Second, KCP&L created a Definitive Estimate. KCP&L's prefiled Testimony describes in detail the process KCP&L used for developing the Control Budget Estimates for both Iatan 1 and 2.[74]

31. Staff and KCP&L agreed that the Control Budget Estimate would serve as the baseline budget for the Projects and the Definitive Estimate from which the Iatan Units 1 and 2 Projects would be measured.[75]

32. Third, KCP&L met its obligation to report on the status of the Definitive Estimate. Once each Project's Control Budget Estimate was in place, the Iatan Project team began tracking costs in the manner described in the Cost Control System.[76]

33. As the Iatan Project progressed, KCP&L met its obligation to "identify and explain" all cost overruns on the Iatan Project. With the Definitive Estimate in place, the Iatan Project team developed a "Cost Portfolio" which it uses for day-to-day tracking and management of Iatan Project's costs.[77]

34. KCP&L's Cost Portfolio comprises the necessary management reports and information needed for cost tracking, cash flow, change order tracking and management.[78]

35. Within the Cost Portfolio, there is a specific report entitled the "K-Report" which is the report that delineates discrete line items of cost including each and every budget change that has occurred along with all costs actually expended.[79]

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[74] Ex. KCP&L 24, pp. 15-18, Ex. KCP&L 43, pp. 6-16.
[75] Tr. 1095-97, 2643-44, Staff's Position Statement, p. 9.
[76] *See* Ex. KCP&L 25, pp. 20-22.
[77] *See* Ex. KCP&L 4, pp. 3-4.
[78] *Id*.
[79] *Id.*

36. KCP&L has provided this report to Staff in summary form each quarter since the creation of the Control Budget Estimate in the first quarter of 2007, and has provided Staff with access to the detailed Cost Portfolio on a monthly basis since that time.[80]

37. Staff admits that KCP&L's cost control system has the ability to track cost overruns. As the Staff's own report states: "KCPL's control budget is very detailed with hundreds of line items. It is clear that KCPL has the ability to track, identify and explain control budget overruns."[81]

38. In keeping with the collaborative process that KCP&L began when it negotiated the Stipulation, KCP&L made every effort at every stage of the process to be fully transparent and accommodating for all the Signatory Parties to access its records and information to ensure that the Iatan Project stayed on track, as well as self-reporting all variances in cost and schedule.[82]

39. Moreover, KCP&L transparently reported each and every major decision that KCP&L makes, the basis for those decisions, the risks both real and perceived and the implications to those decisions to the Project's cost and schedule so that Staff could render its own independent assessment to the Commission regarding KCP&L's prudence.[83]

40. As a prime example of this transparency, KCP&L invited the Staff to participate in the 2008 cost reforecast process and all of the documents that KCP&L

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[80] *See* Ex. KCP&L 25, pp. 22-23.
[81] Ex. KCP&L 205, p. 37.
[82] Ex. KCP&L 25, pp. 20- 25; Ex. KCP&L 44, pp. 9-11.
[83] Ex. KCP&L 25, pp. 20-23; Ex. KCP&L 4, pp. 14-15.

generated in each cost reforecast (collectively the "Cost Reforecasts") were timely provided to Staff for its review.[84]

41. KCP&L also met with Staff at the conclusion of each of the Cost Reforecasts to discuss the resultant changes to the Iatan Project's projected estimate at completion ("EAC").[85]

Cost Variance Identification

42. Mr. Meyer was engaged by KCP&L as part of the Schiff Hardin team and his role on the Iatan Project included examining the changes that have been necessary for each Unit's Control Budget Estimate.[86]

43. Mr. Meyer participated in the oversight of the Iatan Project's base cost estimate that ultimately became the Iatan Project's Control Budget Estimates, each of the Iatan Project's cost reforecasts, and has examined in reasonable detail all of the documents that identify and explain the cost overruns that have occurred on the Iatan Project.[87]

44. Mr. Meyer concludes, "While the Iatan Project is very complex, identifying variances based on the cost system is not, and KCP&L's project documentation, which was readily available to Staff, explains the reasons for those variances."[88]

45. Mr. Meyer provides an overview of this analysis of the Iatan Project costs, which consisted of: "1) Identifi[cation] from a side-by-side comparison of the Iatan

[84] Tr. pp. 1091-92.
[85] Ex. KCP&L 25, pp. 24-25.
[86] Ex. KCP&L 44, p. 3.
[87] *Id.*
[88] *Id*.

Project's Control Budget Estimate and actual costs the largest cost overruns by line-item; and 2) Drill-down through KCP&L's well-organized back-up documentation on each line item so as to obtain a better understanding of the cause of those overruns."[89]

46. The variances were not caused by management imprudence. The size of the overruns was much lower than overall cost increases that were occurring in the industry at-large at the same time for similar projects.[90]

47. Mr. Meyer reviewed the Iatan Project's cost trends as part of his and Schiff Hardin's oversight of KCP&L's four Cost Reforecasts during the life of the Project.[91]

48. Mr. Meyer's analysis is described in detail in his Rebuttal Testimony and attached Schedules. [92]

49. The "drill down" that Mr. Meyer describes involved review of the documents described above from KCP&L's Cost Control System. Starting with the K-Report, Mr. Meyer identified the cost overruns from the Control Budget Estimate. He performed his analysis by narrowing the scope of his review to those items that "on their face appear to be overruns or underruns" which he describes as a standard approach.[93]

50. Mr. Meyer did this by examining the aforementioned K-Report and performing comparisons of the Control Budget Estimate's line items to confirm negative variances without regard to contingency transfers.[94]

51. In other words, Mr. Meyer verified on a line-by-line basis which items cost more than the original estimate anticipated they would regardless of how KCP&L

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[89] *Id.* at 3-4.
[90] *Id.*
[91] *Id.* at 17.
[92] *Id.* at 17-44; Sch. DFM2010-7 to DFM2010-27.
[93] *Id.*
[94] *Id*. at 18.

treated it within its Cost Portfolio. Using this method, Mr. Meyer was able to isolate the cost overruns and examine the root cause of each category of costs where an overrun occurs and thus make a determination regarding KCP&L's prudence in association with that overrun. Mr. Meyer then analyzed and applied the Project's unallocated contingency from the Control Budget Estimate in the same manner as employed by the project team to determine the extent of the actual cost overrun on the Project.[95]

52. Mr. Meyer then examined the Recommendation to Award Letters, Cost Reforecasts, Change Orders and Purchase Orders to evaluate the explanations provided by KCP&L regarding these overruns. Based on this review, Mr. Meyer describes how he initially identified certain items as "omissions" because they were omissions from the Control Budget Estimate and were needed for the construction of the Iatan Project.[96]

53. These omitted costs are essentially scope additions to the Iatan Project and required an adjustment to the Control Budget Estimate due to the fact that these items "could not have reasonably characterized as avoidable costs due to any action or inaction on the part of KCP&L's management.[97]

54. After making these adjustments, Mr. Meyer was left with a list of variances in the K-Report that formed the basis of his analysis.[98]

[95] *Id.* at 18-20.
[96] *Id*. at Sch. DFM2010-14.
[97] *Id*. at 22.
[98] *Id.* at 23.

55. Because Mr. Meyer only evaluated the negative variances (the overruns) and did not take into account any of the positive variances (the underruns), the amount of these negative variances actually exceeded the total overrun for the Iatan Project.[99]

56. Then, utilizing the project's documentation in the Cost Portfolio, Mr. Meyer assessed the identified root causes of these cost overruns, and "bucketed" them into the following five categories:[100]

Reason Code	Definition
1	**DESIGN MATURATION**: This category captures work that is related to the original scope of work, and is necessary for the design or construction of the Unit. This could include field changes or necessary design changes based upon information that became known after the original contract.
2	**PRICING ESCALATION/CHANGES**: This category captures increase in material costs or rates from the original contracted amounts.
3	**NEW SCOPE**: This category captures the cost increases associated with work scope that was never anticipated to be a part of a particular contractor's scope.
4	**DESIGN AND/OR FABRICATION ERRORS**: This category captures scope and costs associated with engineering which caused rework in the field by the affected contractor.
5	**COST INCREASES DUE TO SCHEDULE**: This category captures additional costs paid to the contractor due to delays, compression, acceleration or lost productivity.

57. Mr. Meyer identified the methodology for his categorization of the cost overruns he identified, and explained his reasoning for allocation of costs into each of these categories.[101]

[99] *Id.* at 24.
[100] *Id.* at 26.
[101] *Id.* at 27-29.

58. Mr. Meyer used these reason codes so that these cost items could be understood as part of general categories; however, his analysis required review of the cost items themselves and all related supporting documentation. Mr. Meyer describes the application of these Reason Code Categories in his Rebuttal Testimony.[102]

59. There are two areas of Mr. Meyer's analysis, Design Maturation and Cost Increases Due to Schedule, that encompass the majority of the Iatan Project's cost overruns that Mr. Meyer examined. Based on his drill down from the Project's documentation, Mr. Meyer assigned change orders to Category 1 (Design Maturation) and the related Category 3 (New Scope) that represented costs "the Owner would have incurred regardless of any act or omission on the part of the Owner."[103]

60. Mr. Meyer's analysis of these items was further guided by the concepts of "betterment" or "added value". The Control Budget Estimate was impacted by design maturation:

> **Q: What portions of the Project were most impacted by design maturation in the time period from the December 2006 CBE to June 2008?**
>
> A: For Iatan Unit 2, design maturation most readily impacted areas of the final design that were dependent on the details and workings of the major pieces of plant equipment, functionality of that equipment and operational aspects of that equipment in concert with other systems. Portions of the design that were impacted most by maturation included plant systems such as electrical, water, air, ventilation and mechanical operations. The final design of these plant systems requires significant coordination and a full understanding of the physical size, locations and functionality of adjacent equipment and structural elements.

[102] *Id*. at 25-44.
[103] *Id*. at 27.

Q: Do costs of a project always rise as a result of design maturation?

A: I would not say that "costs rise" due to design maturation but rather one's ability to more accurately forecast the end cost of a project is enhanced as the design is completed and that sometimes results in cost projections increasing. As the design matures and the project's scope becomes more defined, the work quantities and related configurations can more readily be determined. This in turn has an effect on work sequences, overall schedule considerations, work-area sharing arrangements, and time-function expenses. Design evolution enhances an owner's understanding of the nature of a project's various cost streams. As that knowledge and understanding is incrementally accrued, the project's contingency should be re-evaluated in light thereof.

Q: When was the impact of design maturation most apparent on the Iatan Unit 2 Project's costs?

A: During the period between the establishment of the CBE in December 2006 and the May 2008 Cost Reforecast, the design matured from approximately 20% complete to approximately 70% complete. A large percentage of the R&O's that the Project Team had identified during this period reflected the increase of such design maturity.

Q: Based on your analysis of the 2008 reforecasted estimate, did the increase in costs from design maturation that the Iatan Unit 2 Project experienced from December 2006 to May 2008 result from any imprudent acts by KCP&L?

A: No.[104]

61. Because much of the impact of Design Maturation was captured in documentation that KCP&L's Project Team developed in support of the 2008 Cost Reforecast, Mr. Meyer utilized the backup information from this reforecast to measure the impact of the design maturation on the Iatan Project's costs. One example of Design Maturation is the R&O from the Iatan Unit 1 Project's 2008 Cost Reforecast which calls for the inclusion of work on the existing Unit 1 Economizer.[105]

[104] Ex. KCP&L 43, pp. 26-27.
[105] Ex. KCP&L 44, Sch. DFM-2010-06 and Sch. DFM2010-25.

62. Mr. Meyer identified from the documentation that the work involved cooling the exit gas temperature from the existing economizer to the new SCR purchased from ALSTOM, an issue that was not known until after the design had matured and it was recognized that these modifications were necessary.[106]

63. Mr. Meyer explained that this R&O item resulted in changes to both the Iatan Unit 1 budget and schedule.[107]

64. Mr. Meyer concluded that the cost overruns on the Iatan Project that were the result of Design Maturation and New Scope, and the explanations provided by KCP&L show that these overruns were prudently incurred. Mr. Meyer's analysis of the effects of Design Maturation on the Iatan Project's costs is further confirmed by Mr. Davis, Mr. Archibald, Mr. Giles and Mr. Roberts.[108]

65. Mr. Meyer's analysis of the Cost Increases due to Schedule followed the same methodology. Mr. Meyer examined the root causes of the costs related to schedule changes, including those to ALSTOM's schedule of work for Iatan Unit 1 and Iatan Unit 2, resulting in the ALSTOM settlement agreements, and found that the explanation provided by KCP&L's project team was sufficient to support that KCP&L managed these changed conditions prudently.[109]

66. Mr. Meyer's opinion is supported by abundant testimony from Mr. Downey, Mr. Davis, Mr. Bell and Mr. Roberts, who each testified at length regarding the prudence

[106] *Id.*; *see also* Ex. KCP&L 44, pp. 47-49.
[107] *Id.*
[108] Ex. KCP&L 4, pp. 16-22, 25-27; Ex. KCP&L 18, pp. 9-12 (citing to Sch. BCD2010-01); Ex. KCP&L 19, pp. 11, 27-28, 55-58 and 99-100; Ex. KCP&L 24, pp. 20-21; Ex. KCP&L 25, pp. 12, 26-27 and 35; Ex. KCP&L 51, Roberts Rebuttal Testimony pp. 21-24.
[109] Ex. KCP&L 44, pp. 31-34.

of the decisions KCP&L made to compensate ALSTOM for revisions to the Iatan Project's schedule.[110]

67. Mr. Meyer's analysis shows that KCP&L's documentation allows for the performance of a prudence analysis of the Iatan Project's cost overruns. Mr. Meyer's analysis was only one of several such analyses that have been performed. MRA's consultant Mr. Drabinski describes how he and his team reviewed the Iatan Project's change orders and purchase orders and determined the basis for his testimony in this case.[111]

68. Mr. Drabinski agreed that the information provided to him was sufficient for his prudence analysis.[112]

69. While KCP&L disagrees with both Mr. Drabinski's methodology and his conclusions, Mr. Drabinski never raised any concerns with KCP&L's Cost Control System. In addition, while he says he did not examine cost, Mr. David Elliott never had any issues with KCP&L's Cost Control System and was able to perform his analysis of the engineering necessity of the change orders with the documents provided by KCP&L. Mr. Elliott's review included "bucketing" change orders in a manner very similar to the one employed by Mr. Meyer.[113]

70. Dr. Nielsen concluded that but for two examples, his prudence review of the Iatan Project demonstrated that KCP&L prudently managed the Iatan Project. Dr. Nielsen testified that, "Pegasus-Global was able to track cost overruns back to root

[110] Ex. KCP&L 51, pp. 9-10; Ex. KCP&L 22, pp. 35-36; Ex. KCP&L 21, pp. 13-14; Ex. KCP&L 50, pp. 15-16; Ex. KCP&L 18, pp. 20-21; Ex. KCP&L 22, pp. 25-28; Ex. KCP&L 51, p. 7-9; Ex. KCP&L 19, pp. 47-51, 110,; Ex. KCP&L 46, pp. 127-132.

[111] Tr. 1598-9, 1607-8, 1634-6, 1703-4; *see also* Ex. KCP&L 2601, pp. 204-213.

[112] Tr. p. 1586-1590.

[113] Tr. pp. 2398-2400; Ex. KCP&L 205, p. 10; Ex. KCP&L 19, pp. 10-12; Ex. KCP&L 25, p. 14.

causes for those overruns through the project records maintained by KCP&L during the execution of the project."[114]

Staff Perspective of Cost Control System

71. Despite all of the evidence that KCP&L has presented, Staff alleges that KCP&L has exhibited a "knowing and willful disregard of its obligations under the Experimental Alternative Regulatory Plan ('EARP')" by failing to identify and explain cost overruns on the Iatan Project.[115]

72. Staff claims that, "the record will show that the Iatan Construction Project's cost control system does not identify and explain cost overruns as specified in KCP&L's Regulatory Plan but only provides fragmented information regarding budget variances leaving for Staff to identify and explain cost overruns."[116]

73. Staff further claims that KCP&L's cost control system is also "deficient" when compared to those used for Wolf Creek and Callaway.[117]

74. Staff adds that KCP&L's tracking of "budget variances is not what the KCP&L Regulatory Plan requires" because, "budget variances and cost overruns are not necessarily the same thing."[118]

75. However, despite these allegations, as noted, Staff admits that KCP&L had the capability to track cost overruns on the Iatan Project.[119]

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[114] Ex. KCP&L 46, p. 26, ln. 16-20.
[115] Staff's Initial Brief at p. 19.
[116] *Id*. at p. 25.
[117] *Id*.
[118] *Id.* at 39.
[119] Ex. KCP&L 205, p. 37.

76. Staff had full access to the same documents that Mr. Meyer, Mr. Archibald, Mr. Drabinski, Mr. Elliott and Dr. Nielsen had in performing their work.[120]

77. As Mr. Blanc testified, "Staff's Iatan Report reads as though it expected the cost control system to be a piece of paper that lists and explains every dollar spent over the December 2006 CBE. That is an overly simplistic notion and does not accurately represent the purpose of a cost control system, which is to manage the costs of project, which KCP&L's system effectively did."[121]

78. While the Commission has previously approved an adjustment for costs that were deemed to be "unauditable," such a finding has only been made in very extreme circumstances that do not apply here. For example, a category of costs was determined to be unauditable when the utility: (1) failed to have a cost control system in place; (2) failed to provide documentation that could be broken down or traced to the budget; and (3) failed provide evidence regarding its expenditures.[122]

79. Additionally, the Commission has previously rejected Staff's proposed disallowances for "unauditable" costs.[123]

80. For example, Staff alleged that certain categories of costs in the original construction of Iatan Unit 1 were unauditable based on Staff's conclusion that it was

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[120] Ex. KCP&L 44, p. 3*; see also* Tr. 1160-64; Ex. KCP&L 69, p. 19; Ex. KCP&L 70, p. 2, 4, 8, 38.

[121] Ex. KCP&L 8, p. 9.

[122] *See Re Kansas City Power & Light Co.*, 48 P.U.R.4[th] 598, 616 (1982); *see also Re Kansas City Power & Light Co.*, 55 P.U.R.4[th] 468 (1983) (disallowance of "unexplained" costs premised on a complete lack of any competent and substantial evidence, failure of both the Company and Staff to address specific factors or causes for the changes, and the Commission's conclusion that no one knows to what the unexplained differences are attributed.); Staff's Initial Brief at p. 31.

[123] *See Re Kansas City Power & Light Co.*, 48 P.U.R.4[th] 598, 616.

unable to reconcile the costs at issue against any variance report or Staff's definitive estimate.[124]

81. Specifically, Staff asserted the following costs were "unauditable:" (1) the difference between Staff's definitive estimate and the company's definitive estimate; and (2) the project contingency fund.[125] The Commission accepted the company's definitive estimate which eliminated Staff's first category of "unauditable" costs and also rejected the Staff's assertion that the contingency fund was an "unauditable" cost.

82. KCP&L has provided abundant evidence regarding the creation, implementation, and use of an industry standard cost control system for the Iatan Project and all costs incurred on the Project enabling Staff to audit all of the Iatan Project's costs.[126]

83. Project Contingency is an unallocated pool of money that is intended to cover the project's risks as they occur, and that KCP&L's method of distributing contingency on an as-needed basis is standard in the industry.[127]

84. A budget estimate should not determine whether a utility's decision to incur a particular expenditure was prudent:

> I don't really know, other than for regulatory purposes, what any of the budget estimates have to do with prudence. You're not prudent whether you're above or below a budget or cost estimate. You're prudent whether you do something that causes costs to rise due to imprudent or unreasonable management. I don't believe that the control budget or

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[124] In the referenced case, Staff and KCP&L disagreed regarding the what estimate was the "Definitive Estimate." Staff's calculation of "unauditable" costs was based on the estimate it asserted was the Definitive Estimate. In rejecting the Staff's claim of "unauditable" costs, the Commission found that the Company's estimate was what should be used as the Definitive Estimate to determine cost overruns. *See Re Kansas City Power & Light Co.*, 43 P.U.R.4th 559, 585 (1981).

[125] *Id*.

[126] Ex. KCP&L 38, Sch. SJ2010-1; Ex. KCP&L 25, pp. 4, 21-22; Ex. KCP&L 24, pp. 15-18; KCP&L 43, pp. 6-16.

[127] Ex. KCP&L 44. pp. 15-16.

definitive estimate should be a starting point. What if the very first dollar on a project was spent imprudently? Are you not able to go back and identify it and deduct it because it's below the CBE?. . . I don't believe there's a real relationship between cost estimates or budgets with the question before this Commission with what was the reasonable or imprudent cost of the project.[128]

85. Regardless, if Staff did not agree, all it had to do was look at the contingency log that KCP&L provides to Staff each month. Staff could have done what Mr. Meyer did – apply the contingency in exactly the same manner as KCP&L's project team as part of the prudence review.[129]

86. If Staff still had questions, all Staff had to do next was call Mr. Archibald, who opened his calendar every Friday afternoon for Staff to call with questions. Or, Staff could have asked questions in one of the nineteen Quarterly Meetings .[130] If Staff, after applying contingency as KCP&L did, then wanted to examine only those items that were added to the budget after contingency was applied, it easily could have done so. KCP&L identified to Staff where contingency would be exhausted when it informed Staff in the second quarter of 2007 of the need to reforecast the Iatan Project's Control Budget Estimate.[131]

87. Mr. Giles called Mr. Henderson to invite Staff to observe the reforecasting of the Control Budget Estimate that concluded with the 2008 Cost Reforecast, though Staff declined the invitation.[132]

88. Had Staff wanted to look at the actual costs that were expended on the Iatan Project, it could have taken the K-Report referred to above, compared the "Control

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[128] Tr., p. 1713.
[129] Ex. KCP&L 44, pp. 15-16.
[130] Tr. 2216-17; Ex. KCP&L 25: pp. 4, 11-12, 38-41.
[131] Ex. KCP&L 71, pp. 5-7.
[132] Tr. 1091.

Budget Estimate" column with the column labeled "Actuals Plus Accruals," found the contracts where the actual costs exceeded the Control Budget Estimate amount and reviewed the change orders associated with these increases. Such a "list" not only exists, as Mr. Archibald stated, it is reported as part of the regular regime in the Cost Portfolio. Perhaps such an exercise would be time consuming, but it is, in essence, no different than what Mr. Elliott did when he reviewed the engineering necessity of the Iatan Project's change orders.[133]

89. In fact, had Audit Staff merely requested a copy of what Mr. Elliott prepared in his work papers, it would have had a "list" that consists of 227 change orders with a value over $50,000 on Iatan Unit 1 and 647 similar change orders on Iatan Unit 2. However, Audit Staff never once sought Mr. Elliott's assistance in preparing this prudence audit other than the one section he authored for Staff's December 31, 2009 and November 2010 Reports, and didn't know that Mr. Elliott had even prepared these "lists." [134]

90. Mr. Featherstone described a system that Staff once used that combined both pure auditing of costs with the expertise and judgment of the engineering Staff.[135]

91. Engineering conclusions have guided all of Staff's prior audit reports and associated disallowance recommendations. The evidence demonstrated in this case that the Audit Staff did not consult the Engineering Staff in developing its recommended disallowances.[136]

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[133] Tr. 2398-2400; Ex. KCP&L 205, pp. 10, 30-31; Ex. KCP&L 19, pp. 10-12; Ex. KCP&L 25, p. 14
[134] Tr. 2313, 2387, 2400, 2661, 2828.
[135] Tr. 332, 337, 339.
[136] Tr. 2400, 2412, 2421, 2633-34, 2636-37, 2654-55, 2659, 2661.

92. Mr. Henderson took accountability for the change in this procedure, which ultimately resulted in Staff's unprecedented recommended disallowance of all costs over the Iatan Project's Control Budget Estimate based solely on the recommendation of Mr. Hyneman.[137]

93. Staff's approach to the audit of the Iatan Project is especially curious in light of Chairman Gunn's expressed concerns in the April 2010 Hearing:

> But we have an Order saying do an audit, complete—and then we have an order saying complete the audit. We have a brand-new—and this is a Iatan 1, which we've talked about the total cost of this project, which is huge, and we want to get that done because we know that we've got Iatan 2 coming, which is enormous.
>
> And yet it didn't appear to be viewed by anybody that this was an important audit. As a matter of fact, we decided to pull it out of the normal way that we do it and have one person take it on themselves because other people were so reluctant to take it on because there was chaos, that they weren't—they didn't want to do it.
>
> So we have one person doing a—trying to do an enormous audit with an Order of the Commission that potentially conflicts with a position in the—in a stipulation, which could theoretically, under what Mr. Dottheim pointed out yesterday, unravel a Stipulation & Agreement in an enormous rate case that we spent an entire time on it, and no one is expressing this to the Commission. No one is coming in and saying, we have a problem here.
>
> We are stumbling around in the dark. You're putting Band-Aids on that stuff, trying to use the resources that you have, trying to figure out a way to do it, and no one is coming to us and saying, we don't have the resources to complete this. It's just me. I've got people that don't know what they're doing. Operations and services can't get together and pull their stuff together and come up with a single unified plan on how to deal with this.[138]

94. After the April 2010 Hearing, it does not appear that Staff made any significant modifications to its approach to the Iatan Project audit. Mr. Hyneman

[137] Tr. 2299-2300.

[138] File No. EO-2010-0259, Tr. 515-16.

performed most of the audit by himself, with some help on a few issues with Mr. Majors. There was no coordination or unified plan between the Audit Staff and Utility Operations Staff.[139] Finally, Staff failed to raise any issues it was having in performing its audit or utilizing KCP&L's Cost Control System with the Commission.

95. An evaluation of the *Wolf Creek* and the *Callaway* cases provides an interesting comparison of the differences in approach Staff previously employed in its prudence reviews as compared to this case.[140]

96. An important difference in both *Wolf Creek* and *Callaway* from this case is that in those cases, the Staff hired consultants with expertise in the industry to analyze the utility's management of the project and perform an analysis of the costs.[141]

97. Staff, in this case, voluntarily chose not to hire a consultant despite having a budget to do so.[142]

98. Staff's proposed disallowance in this case is inappropriate and inequitable when compared to how the utilities managed the Callaway and Wolf Creek projects, and the resulting disallowances in those cases. As the Companies discussed in their Initial Brief, in Callaway and Wolf Creek, the cost overruns approached 200% and the schedule delays were multiple years.[143]

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[139] Tr. 2400, 2412, 2421, 2535, 2540-41, 2633-34, 2636-37, 2654-55, 2659, 2661.

[140] *See Kansas City Power & Light Co.*, 28 Mo. P.S.C. (N.S.) 228, 290, 75 P.U.R.4th 1 (1986) (regarding the Wolf Creek Generating Station); *Union Electric Company*, 27 Mo. P.S.C. (N.S.) 183, 199; 66 P.U.R.4th 202 (1985) (regarding Callaway Nuclear Plant).

[141] *See Kansas City Power & Light Co.*, 28 Mo. P.S.C. (N.S.) pp. 287-88 (Staff hired Touche Ross & Co. and Project Management Associates to perform a review of the effectiveness of SNUPPS/NPI's management of Bechtel); *Union Electric Company*, 27 Mo. P.S.C. (N.S.) pp. 229-230 (Touche Ross analyzed change/extra work notices).

[142] Tr. 2288-89.

[143] Ex. KCP&L 8, pp. 16-18.

99. In those cases, there were clear problems of owner control over the project, such as the lack of integration of the design and construction schedules, accepting the Contractor's data without any verification, and a complete lack of a cost control or tracking system. The Iatan Project is projected to complete only 15-16% above budget once all the costs are in: it was constructed during a challenging economic climate and finished within three months of the original target date, and the evidence establishes that KCP&L actively managed the Iatan Project and put the proper controls in place.[144]

Specific Disallowances Proposed by Staff

ALSTOM 1 Settlement Agreement

100. A team led by KCP&L that included members of Burns & McDonnell, Kiewit, and ALSTOM determined the most advantageous Unit 1 completion and Outage Schedule was "the Tiger Team Schedule."[145]

101. The Tiger Team ultimately recommended an extension to the Unit 1 Outage to a duration of seventy-three (73) days and a delay to the start of the Unit 1 Outage by approximately one month (the "Tiger Team Schedule").[146]

102. Implementation of this schedule would have a financial impact on ALSTOM for which it was entitled to be compensated under the Contract. KCP&L

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[144] *Id.*
[145] Ex. KCP&L 22, p. 29,
[146] *Id.*

needed ALSTOM to agree to extend the Unit 1 Outage in accordance with the Tiger Team Schedule.[147]

103. ALSTOM agreed to a series of specific interim dates called "construction turn-over" ("CTO") dates to ensure timely completion of ALSTOM's work.[148]

104. KCP&L recognized that since it had entered into the Contract with ALSTOM at the end of 2006, the complexity of the work on the Iatan Unit 1 Outage had increased significantly as KCP&L recognized the opportunity to use this outage to optimize the unit's performance and reduce future performance risk. The added Unit 1 Outage scope included: (1) economizer surface area addition, necessary for the Unit 1 SCR installation; (2) installation of turning vanes in the existing ductwork; (3) upgrades and replacement of the DCS controls; (4) refurbishment of the submerged and dry flight conveyors; and (5) addition of the low NOx burners. In addition, Tiger Team 1 was concerned about the DCS change out, which creates added risk to the unit's start-up. These additions added to the work ALSTOM had to complete within the time frame of the outage as well as added to the general congestion in relatively tight spaces. Additionally, despite the Project Team's efforts, there were a number of open commercial and technical issues that could not be resolved at the Project level. The potential impacts from these unresolved issues were beginning to manifest themselves and it was clear that KCP&L would not be able to resolve them without executive-level involvement. The Quarterly Reports submitted to Staff from the 1st and 2nd quarter of

[147] *Id*. at 28- 29.
[148] Ex. KCP&L 51, p. 10.

2008 reflect these discussions with ALSTOM's management and KCP&L's approach to these issues.[149]

105. Staff has proposed two disallowances based upon the ALSTOM Unit 1 Settlement Agreement.[150]

106. The proposed adjustments are based upon two separate items: 1) the actual amount paid to ALSTOM under the Settlement Agreement; and 2) Staff's calculation of alleged "foregone" liquidated damages.[151]

107. With respect to both proposed disallowances, Staff has failed to "raise a serious doubt" that would override the presumption of prudence. Mr. Hyneman testified that Staff's reasoning for disallowing the costs of the Unit 1 Settlement Agreement was not because the decision to enter into the Settlement Agreement by KCP&L was imprudent, but because it was "inappropriate" to charge the cost of the Settlement to rate payers.[152] By making no determination on prudence, Staff has not overcome the presumption of prudence afforded to KCP&L with respect to this expenditure, as it has failed to raise a serious doubt as to the prudence of the cost of the ALSTOM Settlement Agreement.

ALSTOM Unit 1 Settlement Amount

108. As an initial matter, Staff has failed to raise a serious doubt which would defeat the presumption of prudence afforded to KCP&L. In its pre-filed testimony and November 2010 Report, Staff's reasoning for its proposed disallowance, that "Staff is

[149] Ex. KCP&L 22, pp. 28-29.
[150] Ex. KCP&L 44, Sch. DFM2010-13.
[151] *Id.*
[152] Tr. 2768.

not convinced that ALSTOM's claims against KCP&L were not the fault of KCP&L's project management, raising the question of KCP&L's prudence and whether KCP&L's ratepayers should be responsible for these costs."[153]

109. However, Staff has admitted that it currently does not have an opinion about the prudence of KCP&L's decision to enter into the settlement.[154]

110. Furthermore, neither in Staff's November 2010 Report, nor in its prefiled or hearing testimony does Staff provide any substantive, competent evidence that the amounts paid by KCP&L were due to the fault of KCP&L's project management. In fact, Staff's only evidence is simply a complaint that "KCP&L made no attempt to quantify the costs that may have been caused by its own project management team or the owner-engineering firm it hired, Burns & McDonnell ("B&McD"), or any other Iatan 1 contractor or subcontractor."[155]

111. Staff has not provided any evidence that the amounts paid to ALSTOM under the settlement were caused by B&McD or any other Iatan 1 contractor or subcontractor.[156]

112. Using the management tools available to it, such as the schedule, KCP&L could see when the contractors were not performing as expected. KCP&L would then meet with the contractors weekly and, when necessary, daily to resolve any coordination issues and discuss ways in which the contractor's productivity could be improved and the schedule dates met.[157]

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[153] Ex. KCP&L 205, p. 56.
[154] Tr. 2768.
[155] Ex. KCP&L 205, p. 57..
[156] *Id.*; *see also* Ex. KCP&L 51, p. 9.
[157] Ex. KCP&L 18, p. 20.

113. Additionally, KCP&L set up a sophisticated dispute resolution process with ALSTOM so that it could ensure that it received the best deal possible for itself and its customers.[158]

114. KCP&L organized and participated in several facilitation sessions with a nationally-renowned mediator in order to help find solutions and remediation plans to help get the project back on track.[159]

Unit 1 Liquidated Damages

115. Staff is arguing that an additional adjustment based on KCP&L's alleged choice to forego liquidated damages for ALSTOM's Guaranteed Unit 1 Provisional Acceptance.[160]

116. Under Missouri Law, the term "liquidated damages" refers to "that amount which, at the time of contracting, the parties agree shall be payable in the case of breach."[161]

117. Under ALSTOM's original Contract, KCP&L would be entitled to collect liquidated damages from ALSTOM on Unit 1 ***only*** if ALSTOM was unable to meet its "Provisional Acceptance Date" (otherwise known as the "in-service date") for Unit 1 as required by the Contract. The Unit 1 Provisional Acceptance Date in the ALSTOM Contract was December 16, 2008.[162]

[158] Ex. KCP&L 22, pp. 40-41; Ex. KCP&L 51, p. 8.
[159] *Id.*; KCP&L-51, p. 8.
[160] Ex. KCP&L 205, p. 59.
[161] *See Goldberg v. Charlie's Chevrolet, Inc.*, 672 S.W.2d 177, 179 (Mo. App. 1984).
[162] Tr. 1816-17.

118. This means that KCP&L was not entitled to collect liquidated damages until after that date had passed. KCP&L and ALSTOM negotiated the Unit 1 Settlement Agreement in the first half of 2008 and it was executed on July 18, 2008, several months before any breach could be declared or any liquidated damages had accrued. Once KCP&L and ALSTOM entered into the Settlement Agreement and agreed to modify the Provisional Acceptance date, any discussion about what KCP&L "could have" potentially collected under the original December 2008 contractual date is highly speculative, and completely unrealistic. A contractor is not going to attempt to meet (much less spend additional money to meet) a contractual date that is no longer valid.[163]

119. Two events occurred that show that even if ALSTOM had been late in completing its Unit 1 work, KCP&L would not have been able to collect liquidated damages.[164] These events were the economizer casing repair and the turbine rotor repair.

120. During the Unit 1 Outage, the construction team discovered a latent defect in the economizer casing. This defect and the necessary repairs impacted the duration of the Unit 1 Outage by thirty-two (32) days.[165]

121. Additionally, during the start-up after the Unit 1 Outage, a vibration event with the turbine caused an additional delay to start-up of the Unit.[166]

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163 Ex. KCP&L 22, pp. 36-38; Ex. KCP&L 19, pp. 59-60; Ex. KCP&L 51, pp. 11-12; Ex. KCP&L 46, pp. 266-68.

164 Ex. KCP&L 19, p. 59; Ex. KCP&L 71.

165 *Id.*

166 Ex. KCP&L 19, p. 60.

122. The effect of the economizer incident and the turbine would have made it impossible for ALSTOM to achieve its contractual dates (and even pushed out the revised dates under the Settlement Agreement). These two events added additional time to the schedule, for which ALSTOM was not responsible.[167]

123. As a result, ALSTOM would have been entitled to an adjustment of its contractual Provisional Acceptance Date and KCP&L would not have been able to impose liquidated damages on ALSTOM. Accordingly, the evidence in KCP&L's prefiled testimony and at the evidentiary hearing demonstrate that ALSTOM achieved the contractually modified Guaranteed Unit 1 Provisional Acceptance Date and liquidated damages did not apply.

ALSTOM Unit 2 Settlement Agreement Adjustment

Incentive Payments

124. Staff argues that KCP&L should not be entitled to recover any amounts it paid to ALSTOM under the Unit 2 Settlement Agreement. Staff revised the amount of its disallowance from the November 2010 Report to the total amount KCP&L paid ALSTOM under the terms of the Settlement Agreement. KCP&L's witnesses provided extensive detail regarding the circumstances surrounding the ALSTOM Unit 2 Settlement Agreement, including Mr. Downey, Mr. Roberts and Dr. Nielsen.[168]

125. There were two main reasons KCP&L decided to enter into a Settlement Agreement with ALSTOM. First, ALSTOM had presented KCP&L with a significant delay claim based primarily on weather delays that needed to be resolved. Regardless

[167] *Id*. at 59-60.
[168] Ex. KCP&L 22, pp. 39-47;Ex. KCP&L 51, pp. 12-18; Ex. KCP&L 46, pp. 275-85.

of whether ALSTOM's claim had merit, defending against the claim would be both expensive and time consuming.[169]

126. Additionally, it would have mired the KCP&L and ALSTOM project teams in a commercial dispute at a time when it was important for the focus to be on cooperatively completing the project. Second, Kiewit had told KCP&L that it would cost a substantial amount for Kiewit to be able to support the dates in ALSTOM's schedule.[170]

127. The Commission finds that the value for the benefits KCP&L received exceeded the amount of incentive payments.[171]

128. KCP&L considered and balanced both cost and schedule in creating a revised schedule and fostering cooperation between the main contractors.[172]

129. Based upon a prudence analysis, KCP&L's decision to enter into the ALSTOM Unit 2 Settlement Agreement was a prudent decision when looking at the circumstances known by KCP&L at the time the decision was made.

Unit 2 Liquidated Damages

130. In his true-up testimony, Mr. Hyneman alleges, "Since Alstom's performance compared to contractual requirements were [sic] likely the cause of some if not most of these incremental costs, KCP&L should have assessed and collected these costs from Alstom under the liquidated damages provision of the Alstom-KCP&L contract. KCP&L decided not to make such an assessment. If Alstom's performance

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[169] Ex. KCP&L 51, p. 15.
[170] Ex. KCP&L 22, p. 41.
[171] KCP&L's Post Hearing Exhibit filed on February 22, 2011.
[172] Ex. KCP&L 22, p. 40.

did not meet its contract requirements and failed to protect itself from such performance by taking advantage of its rights under its contract with Alstom, KCP&L was unreasonable / inappropriate in its conduct and should bear the costs incurred."[173]

131. Mr. Hyneman's testimony is transparently based on speculation and hindsight and reveals that Staff has not performed any analysis of KCP&L's prudence regarding its decision to engage in the Settlement Agreement with ALSTOM. Mr. Hyneman also states, "If some or all of the delay in project completion was not the fault of ALSTOM, KCP&L should determine who was at fault and hold that entity (including itself) responsible for these incremental Iatan Project costs."[174] Mr. Hyneman clearly admits that he does not know the basis of this agreement, or whether ALSTOM, KCP&L or anyone else for that matter was "at fault."

132. As stated, the circumstances surrounding the ALSTOM Unit 2 Settlement Agreement and KCP&L's analysis of the agreement are discussed in detail by several KCP&L Company witnesses, including Mr. Downey, Mr. Roberts and Dr. Nielsen.[175]

133. It is mere hindsight to imply that KCP&L could have but did not assess liquidated damages. KCP&L's witnesses provided competent evidence that the Unit 2 Provisional Acceptance date was subsequently revised from the original contract date.[176]

134. Because Staff's proposed disallowance is a calculation regarding what KCP&L "could have" potentially collected had the original contractual date of June 1,

[173] Ex. KCP&L 308, p. 3.
[174] *Id.*
[175] *See* Ex. KCP&L 22, pp. 39-47; Ex. KCP&L 51, pp. 12-18; Ex. KCP&L 46, pp. 275-285.
[176] *See* Ex. KCP&L 112, pp. 10-11; Data Request 658.

2010 remained in effect, the disallowance is not only highly speculative but factually irrelevant.[177]

135. Staff states that there was no evidence of KCP&L's analysis quantifying the events associated with the Unit 1 ALSTOM Settlement Agreement.[178]

136. However, the record establishes that KCP&L has provided Staff with all necessary documents related to the ALSTOM Unit 1 Settlement and that the agreement was prudent. Staff had access to KCP&L project management and senior project staff, and KCP&L has filed extensive testimony regarding this issue in File No. ER-2009-0089 ("0089 Case").[179]

137. KCP&L has put forth credible testimony of industry experts such as Dr. Nielsen and Mr. Roberts who have testified that the ALSTOM Unit 1 Settlement was a prudent expenditure on the part of KCP&L, and KCP&L witnesses who testified as to the detailed evaluation that was performed.[180]

138. The evidence establishes that KCP&L fully evaluated the benefits and risks associated with the ALSTOM Unit 1 Settlement Agreement. The evidence establishes that KCP&L's decision to settle with ALSTOM was prudent in light of all of the circumstances and information known to KCP&L's senior management at the time.

139. Mr. Hyneman also alleges, "Since Alstom did not obtain Provisional Acceptance of Iatan Unit 2 until September 23, 2010 when it was required by contract to

[177] *See* Ex. KCP&L 112, p. 6; Ex. KCP&L 22, p. 36-38; Ex. KCP&L 19, p. 58-60; Ex. KCP&L 51, p. 11-12; Ex. KCP&L 46, pp. 266-268.
[178] *See* Staff's Initial Brief at p. 48.
[179] *See* Davis Rebuttal Testimony (0089 Case) at pp. 3-6 and 19-20 (discussing the Unit 1 Outage and the Tiger Team Schedule and describing meeting with the MPSC Staff that occurred on September 23, 2008 where the Unit 1 Settlement was discussed in detail and relevant documents were provided); Downey Rebuttal Testimony (0089 Case) at p. 17 ln. 20 to p. 20, ln. 23.
[180] Ex. KCP&L 46, pp. 263-275; Ex. KCP&L 51, pp. 7-12; Ex. KCP&L 22, pp. 28-29, 32, 34, Sch. WHD2010-05.

obtain this project milestone on June 1, 2010. Because of this delay in project completion, KCPL incurred costs and harm."[181]

140. This is the identical argument that Staff advances in Staff's Report regarding the "forsaken" liquidated damages on the Iatan Unit 1 Project, and will be rejected for the same reasons KCP&L's witnesses have previously articulated.[182]

141. Although KCP&L technically declared that ALSTOM met the Provisional Acceptance Date on September 23, 2010, it could have done so much earlier, but chose not to for valid commercial reasons:

> Technically, KCP&L could have declared that ALSTOM had achieved Provisional Acceptance on this date, but chose to rely on some technical language in the Contract so that KCP&L could wait until after ALSTOM could show that the unit could be started up with no problems after an extended outage. This was to ensure that there were no latent problems in ALSTOM's work before KCP&L released ALSTOM from liability for liquidated damages. As a result, KCP&L considers the "commercial operation" date (the definition on which Provisional Acceptance is based) of the Iatan Unit 2 plant to be August 26, 2010, or 67 days earlier than ALSTOM's [revised] contractual date. It is important to note that KCP&L has always targeted Provisional Acceptance for the Project in the "Summer of 2010", which was achieved. KCP&L does not consider the Iatan Project to have been "late."[183]

142. Because Staff's proposed disallowance is a calculation regarding what KCP&L "could have" potentially collected had the original contractual date of June 1, 2010 remained in effect, the disallowance is not only highly speculative but factually irrelevant. ALSTOM was not required to nor would it have any reason to attempt to

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[181] Ex. KCP&L 308, p. 3.

[182] Ex. KCP&L 112, p. 5-12; Ex. KCP&L 22, pp. 36-38; Ex. KCP&L 19, pp. 59-60; Ex. KCP&L 51, pp. 11-12; Ex. KCP&L 46, pp. 266- 268; Ex. KCP&L 205, p. 59.

[183] Ex. KCP&L 112, pp. 10-11.

meet (much less spend additional money to meet) a contractual date that is no longer valid.[184]

Schiff Hardin LLP Adjustments - Iatan

143. Schiff Hardin brought value to the Iatan Project, from the initial setup of the commercial strategy and strategic schedule, the negotiation of the Iatan Project's contracts through the Project itself, all the while providing KCP&L's senior management team information it needed to oversee the Iatan Project's management.[185]

144. He is not an attorney himself, and has not presented any evidence that he has ever contracted for legal services at any point in his career.[186]

145. Mr. Hyneman admits that he is not an expert at evaluating the quality of legal work and he is not offering an opinion as to the quality of Schiff's work on the Iatan Project. [187]

146. KCP&L's procedures do not require that all services are subjected to a competitive bidding process.[188]

147. Moreover, there was considerable vetting of Schiff Hardin and their fees, not just at the outset of the Project but also as the Project progressed.[189]

148. KCP&L's decision to utilize Schiff Hardin was well considered on the basis of a vetting of both the needs for a firm of this type and the Schiff Hardin's unique set of

[184] *Id.* at 6; Ex. KCP&L 22, pp. 36-38; Ex. KCP&L 19, pp. 58-60; Ex. KCP&L 51, pp. 11-12; and Ex. KCP&L 46, pp. 266-268.
[185] Ex. KCP&L 8, pp. 22-23; Ex. KCP&L 22, p. 6; Ex. KCP&L 25, p. 16, Ex. KCP&L 19, p. 5; Ex. KCP&L 6, p. 2.
[186] Tr. 2589.
[187] Tr. 2649-50.
[188] Ex. KCP&L 8, pp. 20-21.
[189] Tr. 1436-37.

qualifications, and KCP&L's day-to-day management of Schiff Hardin's work was robust.[190]

149. Schiff Hardin only performed the work that KCP&L requested it perform, and the quality of their work and their advice is not being questioned.[191]

150. If only hours incurred by Schiff Hardin personnel were considered, then the statistics would reflect Iatan Oversight (32%), Iatan Project Control (10%), Contracts (10%), Contract Administration (46%) and other (2%).[192]

151. KCP&L has demonstrated that using Schiff Hardin to provide legal services on the Iatan Project, was prudent because of Schiff Hardin's qualifications to perform such work.[193]

Pullman Adjustment

152. Pullman was a contractor on the Iatan Construction Project and part of its duties was to install the new chimney liner.[194]

153. Although Staff includes in Schedule 1-1 of its November 2010 Report two proposed disallowances related to Pullman, the Chimney contractor, there is no explanation anywhere in Staff's November 2010 Report as to Staff's evaluation of these costs or why they have been deemed to be imprudent.

154. Staff's argument that a statement in the Kiewit Recommendation to Award Letter that "Pullman's Performance on the Project was well below expectations" does not explain why Staff would disallow the costs to put a performance bond in place,

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[190] Tr. 1439-41.
[191] Tr. 1644; Ex. KCP&L 1203, p. 82.
[192] Ex. KCP&L 8, p. 31.
[193] Ex. KCP&L 8, pp. 20-21; Tr. 496-503, 1436-37, 1439, 1441, 1644, 1860-62.
[194] Ex. KCP&L 250, p. 8.

nor is there any analysis that identifies 1) how KCP&L had Pullman's performance within its control; or 2) how KCP&L acted imprudently that led to the disallowed costs. By its silence, Staff has not created a "serious doubt" as to these expenditures. Thus, Staff has not created a "serious doubt" as to these expenditures and base upon a prudence analysis, KCP&L's payments to Pullman are deemed to be prudent.

155. The sole basis for Staff's disallowance is the Commission's "recent" decision in 2006 that severance costs should not be recovered from rate payers.[195]

156. However, the Commission finds that severance costs in this case are an ongoing cost KCP&L incurs to serve its customers.[196]

Affiliate Transaction

157. Staff has proposed a disallowance for costs incurred by KCP&L's affiliate, Great Plains Power ("GPP") for work performed that was ultimately used as a part of the development of the Iatan Unit 2 project. As cited by Staff in its November 2010 Report, KCP&L identified the work performed as pertaining to "environmental permitting and engineering which defined the project scope and plant design."[197]

158. Staff's simply states that it "was not convinced that the costs incurred by GPP in its nonregulated activities were necessary for the construction of Iatan 2." However, Staff's November 2010 Report does not identify the reasons for this belief, nor

[195] *See* Staff's Initial Brief at pp. 46-47.
[196] Ex. KCP&L 23 (NP), p. 4.
[197] *See* Ex. KCP&L 205, p. 51.

does it provide any sort of prudence analysis of the costs incurred.[198] As a result, Staff has not raised a serious doubt as to the prudence of these costs that can overcome the presumption of prudence afforded to KCP&L. Based upon a prudence analysis, the affiliate transactions were prudent when looking at the circumstances known by KCP&L at the time the decision was made.

159. The use of existing GPP development work resulted in a substantial reduction in schedule and additional costs that would had to have been recreated or incurred going forward.[199]

160. The site where GPP began the development of its generation facility became the site that is known as the Iatan 2 generation facility. Work that had already been completed by the GPP subsidiary regarding initial environmental permitting and engineering was applicable and beneficial to the development of Iatan 2.[200]

161. It would not have been in the best interest of rate payers to recreate the work and delay schedule simply due to the fact that the initial development of Iatan 2 generation facility began with the GPP subsidiary.[201]

162. As far as the affiliate transaction rule (4 CSR 240-20.015(2)(A), the rule requires that the compensation to GPP be the lower of the fair market price or the cost to provide the services for itself. In this case, it would have been of no value to complete a market review of what it would cost to do an environmental permitting and

[198] *Id.*
[199] Ex. KCP&L 113, p. 15.
[200] *Id.*
[201] *Id.* at 16.

engineering study at the time of purchase of the GPP work as the study was being purchased at cost.[202]

163. The Companies agree that they were in error for not reporting the transaction in the annual affiliate transaction report. However, this reporting failure does not change the fact that certain environmental and engineering needed to take place.[203]

Additional AFUDC Due to Iatan 1 Turbine Start-Up Failure

164. Staff has not proposed an adjustment for the costs of the turbine trip. AFUDC costs are a component of the project's total costs and the turbine work was required to return Iatan Unit 1 and the AQCS environmental upgrades to service.[204]

165. In Staff's November 3 report, Staff made an adjustment regarding AFUDC costs incurred on the Iatan 1 AQCS project during the outage associated with the turbine trip. Staff's rationale was "it is Staff's belief that the increase in AFUDC accrued during the 33-day delay should be removed from plant balance of the Iatan 1 AQCS and charged to the work order capturing the costs for the turbine trip."[205]

166. The turbine work (including new rotor installation, replacement of low pressure sections to increase output, reworking of turbine spindle in or to support the performance of the new AQCS equipment) was required to support the Unit 1 AQCS retrofit project.[206]

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[202] *Id.* at 16.
[203] *Id.* at 15.
[204] *See* KCP&L/GMO's Initial Brief at ¶193.
[205] Ex. KCP&L 205, p.90; Ex. KCP&L 201, p. 124; Ex. KCP&L 113, p. 10.
[206] *See* Ex. KCP&L 19, p. 61.

167. Staff has not proposed any disallowance associated with the turbine trip work, but attempts to penalize the Companies for the turbine failure by not allowing the AFUDC costs incurred on the Iatan 1 AQCS project costs during the outage associated with this work. AFUDC costs are a component of the construction projects total costs and shall not be disallowed when costs associated with prudent work required to return the unit to service have not been proposed to be disallowed.[207]

Advanced Coal Credit AFUDC Adjustment

168. Staff argues that since KCP&L had a free source of cash from Section 48 advanced coal investment credits from 2007 to 2009, it had access to free cash flow to offset the financing costs for the construction of Iatan 2.[208]

169. Staff's free cash flow position is unsupported and unfounded as it attempts to impute a cost savings that does not exist and ratepayers will receive the benefits of the advanced coal investment tax credits over time. As explained by Company witness Ives, the borrowing or financing costs of KCP&L and GPE did not increase as a result of GPE not utilizing the advanced coal investment tax credits in 2008 and 2009.[209]

AFUDC Accrued on Staff's Proposed Disallowances

170. Staff has calculated the AFUDC value associated with each of the proposed construction cost disallowances detailed in the Staff's "Construction Audit and Prudence Review" report of the Iatan Construction Project which was filed on

[207] *See* Ex. KCP&L 113, p. 11.
[208] *See* Staff's Initial Brief at p. 77.
[209] Ex. KCP&L 113, p. 13.

November 3, 2010, as updated on Schedule 1 to Staff witness Hyneman's true-up direct testimony.[210] AFUDC and carrying costs related to any specific adjustment should follow that adjustment.

JLG Accident Adjustment

171. Staff believes that KCP&L was unreasonable for executing the JLG Settlement Agreement.[211]

172. KCP&L and ALSTOM chose to escalate this issue for resolution as part of a broader commercial strategy, and that this issue was one of several that KCP&L and ALSTOM ultimately resolved in this manner.[212]

173. In its November 2010 Report, Staff has failed to raise a serious doubt as to the prudence of KCP&L's settlement of the JLG accident costs. Based upon a prudence analysis, KCP&L's decision to settle ALSTOM's JLG claim was a prudent decision when looking at the circumstances known by KCP&L at the time the decision was made.

May 23, 2008 Crane Accident Adjustment

174. On May 23, 2008, one of the largest mobile cranes in the world, a Manitowoc 18000 crane, collapsed while performing an unloaded test lift on the Iatan

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[210] *Id* .at 8.
[211] Ex. KCP&L 205, p. 46.
[212] Ex. KCP&L 19, pp. 54-55.

Project (the "Crane Incident"). As a result of the collapse, one person was killed and others were injured.[213]

175. KCP&L's EPC Contractor, ALSTOM, was responsible for the operation of the crane at the time of the incident.[214]

176. In Staff's November 2010 Report, Staff disallowance is based on a meeting that Staff had with KCP&L, and Staff's "impression" regarding KCP&L's expected future recovery of the costs associated with the Crane Incident.[215]

177. Staff admits that it has not done a detailed review of project costs to determine if the charges are accurate and complete, even though many of these charges were incurred by KCP&L over two years ago.[216]

178. Staff has failed to raise a serious doubt as to the prudence of these expenditures. Based upon a prudence analysis, KCP&L's decision to take swift action immediately after the Crane Incident on the Iatan Site was a prudent decision when looking at the circumstances known by KCP&L at the time the decision was made.

179. The Commission finds that the costs incurred by KCP&L due to the Crane Incident were prudently incurred.[217]

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213 Ex. KCP&L 22 (NP), p. 14.
214 *Id.*
215 Ex. KCP&L 205, p. 41.
216 *Id*.
217 Ex. KCP&L 22, pp. 23-24.

Cushman Project Management Rate Adjustment

180. Staff's proposed disallowance for a rate adjustment relating to Mr. Cushman's fees was based on an assessment that Mr. Cushman's fees were unreasonable.[218]

181. Cushman was hired to develop processes and procedures for the Iatan Project including the Project Execution Plan ("PEP"). Mr. Cushman is highly respected in the industry and had a proven track record with KCP&L from Hawthorn.[219]

182. KCP&L evaluated the costs for Cushman's specialized services and determined that the costs were reasonable.[220]

Adjustment from KCC Staff Audits

183. Staff proposes adjustments in the amount of almost $2 million based on a KCC Staff audit. The KCC Staff audit is not before this Commission and is non-credible hearsay. The fact that KCP&L decided not to challenge those adjustments in its Kansas case does not in and of itself create a serious doubt as to the imprudence of those expenditures. KCP&L has denied that those expenditures were imprudent. Because Staff presented no evidence of imprudence, the Commission finds the costs were prudently spent on the Project.[221]

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[218] Ex. KCP&L 205, p. 98.
[219] Ex. KCP&L 19, p. 66.
[220] *Id*.
[221] Ex. KCP&L 19, pp. 71-72.

Employee Mileage Charge Adjustment

184. Employees assigned to the Iatan Project were only going to be travelling to Iatan on a temporary basis.[222]

185. To require employees to work at the Iatan project site on a temporary, five-year project without compensation for mileage costs would not have been equitable and likely would have been viewed as a deterrent to working on the Iatan projects.[223]

Inappropriate Charges Adjustment

186. Staff has attached Schedules 4 and 5 that purport to support Staff's disallowances for the inappropriate charges. However, the Schedules identify only $18,351 of items charged to Unit 2 that Staff deemed as inappropriate. Staff's amount for the proposed disallowances are only "estimates" which are wholly arbitrary.[224] Staff has no basis for its estimates, and as a result, they will be disregarded by the Commission.

Disallowances Proposed by Missouri Retailers Association ("MRA")

Iatan 2

187. There are significant portions of Mr. Drabinski's testimony on behalf of the MRA that are not only flawed from a factual and analytical standpoint, but they do not factor in any way in Mr. Drabinski's actual recommendation for the disallowance of $219 million. These include Mr. Drabinski's allegations that:

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[222] Ex. KCP&L 8, p. 39.
[223] *Id*.
[224] Ex. KCP&L 8, p. 40.

- Mr. Drabinski's entire "Plant Comparison" analysis, "Comparison to Trimble County 2" and "Analysis of Budgets and Reforecasts", which he abandoned in exclusive favor of his single recommended $219 million disallowance.[225]

- Any measured cost "increase" from any project estimate prior to the December 2006 Control Budget Estimate, including Mr. Drabinski's claim that a preliminary estimate prepared in January 2006 has some significance.[226]

- Mr. Drabinski's repeated allegation that KCP&L mismanaged the Project "early on," which he defines as the year 2006 to early 2007. This unsupported opinion based in hindsight conflicts with Mr. Drabinski's testimony that KCP&L pursued the critical path work through 2006 with great success.[227]

- Mr. Drabinski's allegation that Burns & McDonnell was "late" in producing critical drawings is completely contradicted by the fact that Burns & McDonnell completed the foundation drawings on time for critical turnovers to ALSTOM and Kiewit.[228]

- Mr. Drabinski's hindsight-based allegation that KCP&L's decision related to the Iatan Project's contracting methodology, i.e. to perform the Iatan Project on a multiple prime and not an EPC basis, increased the Project's cost (i.e., EPC vs. Multi-Prime) or was in and of itself imprudent.[229] Drabinski testifies, "I never stated that the decision to use a Multi-Prime rather that an EPC approach was, in itself, imprudent."[230]

- KCP&L and Kiewit had some specious deal regarding an artificially low contract price.[231]

- KCP&L made an untimely decision to hire Kiewit as the primary Balance of Plant ("BOP") contractor at a premium price; as explained further below, Mr. Drabinski does not know how to quantify this alleged premium.[232]

- The "turbine building bust" and "the cost of the unintended consequences of the decision to add a de-aerator to the project. Evidence shows that the cost of the enlarged turbine building was at least $106 million and perhaps over $200 million. This was part of the reason for the large increase in balance of

[225] Tr. 1597.
[226] Tr. 1593-1594.
[227] Tr. 1648-1653.
[228] Tr. 1650.
[229] Tr. 1593.
[230] Ex. KCP&L 2602, p. 24.
[231] Ex. KCP&L 2601, p. 159.
[232] Ex. KCP&L 45, pp. 47-53.

plant costs."[233] Company witness Mr. Meyer explains that while the Balance of Plant work increased due to design maturation, these were not in any way imprudent cost increases, as Mr. Drabinski obliquely asserts without examination of the facts.[234]

- The cost of the Balance of Plant work increased from "$350 million to a billion dollars on this Project."[235]

- KCP&L could not manage a multi-prime project, a fact disputed by numerous KCP&L witnesses.[236]

- The development and implementation of the PEP and other project tools such as SKIRE were untimely and increased Project costs; a fact disputed by numerous KCP&L witnesses and which Mr. Drabinski never ties to any disallowance. The contracts used for the major contractors were inadequate in that these contracts did not adequately shift risk to the contractors and did not contain a formulaic basis for calculating loss of efficiency change orders. Mr. Drabinski never cites a single sentence in any contract that was employed on the Iatan Project, yet he concludes that KCP&L employed "poorly written contracts" because "every time a problem arose, rather than being able to use the contract to resolve it, they went to a settlement.[237]

- KCP&L failed to timely implement expert advice, which Mr. Roberts thoroughly disputes.[238]

- KCP&L's planned construction schedule was compressed and was made worse by KCP&L's failure to timely hire Burns & McDonnell as the Owner's Engineer.[239]

188. Dr. Nielsen credibly addresses Mr. Drabinski's failure to create a nexus between KCP&L's alleged imprudent actions and his proposed disallowances in his Rebuttal Testimony. Specifically, Dr. Nielsen testifies:

> Pegasus-Global's examination of Mr. Drabinski's "Review of Purchase Orders and Change Orders" determined that Mr. Drabinski again provided

[233] Ex. KCP&L 2601, p. 33.
[234] Ex. KCP&L 45, pp. 48- 49.
[235] Tr. 1615.
[236] Ex. KCP&L 6, pp. 14-15; Ex. KCP&L 19, pp. 20-26, 104-107; Ex. KCP&L-21, p. 27; Ex. KCP&L-22, pp. 74-80; Ex. KCP&L 46, pp. 94-97; Ex. KCP&L 52, pp. 33-44.
[237] Tr. 1645.
[238] Ex. KCP&L 52, p. 2.
[239] *Id.* at 45-47.

> no nexus of causation between any unreasonable or imprudent decision or action by KCP&L and specific cost disallowance. Mr. Drabinski simply notes that its “analysis was in-depth and extremely data intensive” [Drabinski Direct Testimony at p. 204, ln. 11] and that based on that analysis it ”determined if all or part of the cost should not be permitted into the rate base” [Drabinski Direct Testimony at p. 204, ln. 19 through p. 205, ln. 1]. Nowhere in Mr. Drabinski’s testimony was there a single statement which linked a specific Purchase Order or Change Order, or a part of a specific Purchase Order or Change Order, to any decision made or action taken by KCP&L during the execution of the Iatan Unit 2 project.[240]

189. Mr. Drabinski’s Direct Testimony includes four separate methodologies and four separate potential disallowance calculations though he agreed at the hearing that the only actual recommendation that he is advancing to the Commission is his so called “Review of Initial Purchase Orders and Change Orders.”[241]

190. Mr. Drabinski makes only a cursory attempt to tie a handful of the proceeding two-hundred and two pages of his Direct Testimony to this final section of his actual recommendation to the Commission. On one hand, Mr. Drabinski claims that his recommended disallowance is tied to specific Purchase Orders and Change Orders.[242]

191. However, he described his method of choosing the change orders that make up his recommended disallowance as follows:

> How you come up with the allocation of imprudent costs is not based on a specific purchase order, but based on the overall testimony that shows that imprudent mismanagement took place, costs rose beyond expectations and reasonable levels and, therefore, certain areas warrant adjustment.[243]

[240] Ex. KCP&L 46, p. 227.
[241] Ex. KCP&L 2601; Tr. 1597.
[242] Tr. 1601.
[243] Tr. 1638-39.

192. Fifteen major flaws are apparent in Mr. Drabinski's analysis.[244]

1) Drabinski applied an erroneous standard for prudence reviews.

2) Drabinski finds imprudence as a consequence of the results attained rather than evaluating decisions and the decision making process, causally connecting the allegations and then properly quantifying the impact.

3) Drabinski improperly asserts that Drabinski's opinion is preferable to prudence opinions which may be held by the Commission.

4) Drabinski improperly asserts that Drabinski's opinion is preferable to KCP&L's management decisions and improperly employs hindsight in doing so rather than evaluating management decisions made at the time.

5) Drabinski did not perform a prudence audit, but rather, engaged in what is essentially an inappropriate mixing of construction claims approaches and construction/financial audit approaches.

6) Drabinski failed to recognize the Iatan Project as a mega-project and thus, failed to evaluate the Iatan Project within the proper context of that definition.

7) Drabinski used selected "sound bites" drawn from internal audits and consultant reports performed by or at the request of KCP&L to support Drabinski's assertion of imprudence, ignoring information from those audits which runs contrary to Drabinski's position and not presenting these selections in context, including the proper time context.

8) Drabinski inappropriately uses KCP&L's internal audits to criticize KCP&L's decisions ignoring the fact that the process of conducting on-going internal audits during a complex construction project is considered part of the prudent management decision making process.

9) Drabinski's opinion relies upon an incorrect understanding of facts, and often directly conflicts with documented evidence regarding events on the Iatan Project, and conditions and circumstances that were known and/or reasonably known by KCP&L management.

10) Drabinski submits conclusions of imprudence without providing supporting explanation or documentation other than the selected "sound bites".

[244] Ex. KCP&L 46, pp. 27-30.

11) Drabinski fails to provide a connection between Drabinski's allegations of imprudence and any actual costs incurred as a direct result of the alleged imprudence.

12) Drabinski's analyses and conclusions display a lack of experience and understanding of construction industry practices, procedures and standards on a project like the Iatan Project. For example, Drabinski's analyses and conclusions display a misunderstanding of the cost estimating process and the proper use of various levels of cost estimates created during the planning and execution phases of a mega-project like the Iatan Project.

13) Drabinski substitutes his judgment rather that analyzing whether KCP&L's decision-making processes and procedures, and KCP&L's decisions fell within a zone of reasonableness, and thus would be prudent.

14) Drabinski uses impermissible hindsight to determine prudence.

15) Drabinski's analyses and conclusions filed in this case are inconsistent with testimony filed by Drabinski in the Kansas Commission case in July 16, 2010. For example, in the Kansas Commission case Mr. Drabinski testified that the project peer review differential it calculated supported a disallowance of $530 million while in Drabinski's filed testimony in this MPSC case the project peer review differential he calculated supported a disallowance of $316 million, a difference of $214 million. The Kansas Commission in its 21 November 22, 2010 Order (Docket No. 10-KCPE-415-RTS) also found that Drabinski's analysis was flawed for similar reasons noted above and stated in that order.

193. Mr. Drabinski testified at the hearing:

I made significant changes to my testimony, both as far as the prudence standard, and I also added a significant amount of analysis and detail based on what I learned from the time that my testimony was produced in the spring of 2010 until November 2010 when it was due here. You don't sit through weeks of hearing and go through thousands of data requests without learning a little more."[245]

194. While the 'perfect' estimate may be an industry goal, it rarely, if ever, exists in reality. It is not uncommon within the industry to see cost increases. In other words, even if KCP&L had a 'perfect' estimate back on day-one of the Project, KCP&L

[245] Tr. 1707.

would still have incurred these costs but the Control Budget Estimate would have been higher."[246]

Iatan 1

195. Mr. Drabinski has proposed a $13,938,795 disallowance for Iatan 1 (or $5,220,079 KCP&L Missouri Jurisdictional share and $2,508,983 GMO share) based upon an analysis he performed for the Kansas Commission almost two years ago.

196. The Commission finds that Mr. Drabinski has failed to provide the Commission with substantive and competent evidence to support those disallowances. MRA's recommended disallowance is based upon Mr. Drabinski's identification of five separate R&O (Risk/Opportunity) packages related to the Iatan Unit 1 AQCS and Common plant projects that he believes reflect KCP&L's management's imprudence.[247]

197. KCP&L's witnesses provided substantial evidence regarding the prudence of these expenditures.[248]

Iatan Disallowances

WSI

198. KCP&L's Prudence consultant, Dr. Kris Nielsen of Pegasus-Global, whom the Commission finds credible, asserts that expenditures paid to ALSTOM in connection with work performed by WSI in an effort to overcome ALSTOM's failure to adhere to

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[246] Ex. KCP&L 44, p. 27.
[247] *See* Ex. KCP&L 2601, Sch. WPD-8.
[248] *See* fn. 54-56, 60-61, 65-66, 90-91, 94, 96, 99, 106, 108, 112-114, 146-170, 188-196, 205-06, 214-17, *supra*.

schedule were imprudent. KCP&L's consultant further determined that costs incurred by KCP&L in connection with the ALSTOM/WSI work, were imprudent.[249]

199. Dr. Nielsen recommended a $12.7 million disallowance in connection with the ALSTOM/WSI work and concomitant KCP&L costs. Staff concurs in Dr. Nielsen's quantification of these imprudent costs, and recommends their disallowance from rate base.[250]

200. ALSTOM was responsible for costs due to delays unless the delays were the result of actions by KCP&L or a third party responsible to KCP&L.[251]

201. Staff reviewed relevant WSI change orders and found no evidence that the ALSTOM-related delays were the responsibility of KCP&L or any party responsible to KCP&L.[252]

202. KCP&L's prudent course would have been to hold ALSTOM responsible financially for the costs associated with recovering the ALSTOM work schedule, including work performed by WSI. KCP&L's ratepayers should not bear financial responsibility for these charges that should have been appropriately borne by ALSTOM.

Temporary Boiler

203. Removal and readdition of auxiliary boiler was imprudent, and costs of $5,346,049 should be disallowed.[253]

[249] See Ex. KCP&L 210, pp. 100-101.
[250] *Id.*
[251] *Id.*
[252] *Id.*
[253] Ex. KCP&L 46 (NP), p. 17; Tr. 2089.

204. In highly confidential testimony, Nielsen credibly explained why those costs should be disallowed.[254]

Campus Relocation

205. The original campus design and location was developed in the summer and fall of 2006. Facility construction began in the summer of 2006. The initial trailers on site were for KCP&L, and the major Iatan construction contractors, Kissick, Pullman, and ALSTOM, each of whom mobilized to the site in late-summer and fall of 2006.[255]

206. In the summer of 2007, the balance-of-plant contractor, Kiewit, developed a revised plan for laydown space needed for access to the turbine generator building. This plan included providing a new path for unloading the turbine generator into the turbine bay.[256]

207. Kiewit's plan necessitated moving the existing campus trailers to provide the area for laydown space. Additionally, Kiewit's new plan of where it wanted to locate erection cranes caused concerns because Kiewit would be lifting loads near or over the campus. Each of the trailers was moved approximately 100 feet east in the spring and summer of 2008.[257]

208. Total cost incurred for the campus relocation through June 2010 is $1,563,727. Of this amount, KCP&L charged $456,608 to Iatan 1 and $1,107,119 to Iatan 2.[258]

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[254] Ex. KCP&L 46 (HC), pp. 235ff.
[255] Ex. KCP&L 205, p. 43.
[256] *Id.*
[257] *Id.*
[258] *Id.*

209. The only justifiable reasons why KCP&L would agree to incur over $1.6 million in costs to relocate construction trailers at the Iatan site is

> 1) KCPL realized the original design and location of the Iatan campus was faulty and did not provide sufficient room and laydown space for the transporting the turbine generator into the Iatan 2 turbine bay. In this case KCPL would incur the cost and seek backcharges from the contractor who was responsible for the campus design and trailer locations. The backcharged costs would be credited against the project when collected.
>
> 2) The cost savings or other benefits to the Iatan construction project resulting from the relocation would exceed the cost of the relocation charged to the project. In other words, the design and location of the campus was sufficient for the successful completion of the project but a change in the trailer locations would result in project savings and/or other benefits that exceed the cost of the relocation.[259]

210. Staff requested a meeting with KCP&L on this issue, and the meeting was held on December 7, 2009. In attendance at this meeting was Mr. Eric Gould, a Schiff Project Controls Analyst. Mr. Gould advised that the relocation resulted in cost savings. He advised Staff that he was going to look for documentation of cost savings on the Balance of Plant contract as a result of the $1.6 million campus relocation. Subsequent to this meeting Staff has been advised that Mr. Gould was unable to locate any documentation supporting a cost savings associated with the campus relocation.[260]

211. The allocation of any costs of the campus relocation to the Iatan Project is inappropriate. The reason for the cost appears to be a significant design error. The most appropriate method for KCP&L to recover these costs is to seek backcharges for the cost of this work from the entity who was responsible for the design of the construction campus laydown area.[261]

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[259] *Id.* at 43-44.
[260] *Id.*
[261] *Id.*

212. According to information from KCP&L, a design error occurred.[262]

213. If the campus were designed correctly, there would have been enough space between the campus and where the boiler had to go.[263]

214. Moving the campus essentially doubled the cost of constructing the campus.[264]

215. Because KCP&L's original design and location of the Iatan campus was faulty, KCP&L incurred expenses in moving construction trailers at the Iatan site approximately 100 feet east when construction began on the turbine generator building.[265]

216. Correction of KCP&L's failure to engage in adequate planning prior to initially siting the trailers – or KCP&L's failure to adequately design the initial siting of the trailers – is not of benefit to Missouri ratepayers. Costs incurred to correct this faulty design should not be borne by Missouri ratepayers.[266]

Construction Resurfacing Project Adjustment

217. KCP&L paid money to ALSTOM in connection with claims related to delays to ALSTOM's work and acceleration of other ALSTOM work related to the Iatan site being resurfaced.[267]

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262 Tr. 2659.
263 *Id.* at 2817.
264 *Id.* at 2817-18.
265 Ex. KCP&L 210, p. 43.
266 Ex. KCP&L 89 (HC).
267 Ex. KCP&L 205, p. 47.

218. KCP&L also paid to have the site resurfaced.[268] The Commission found no credible evidence that the site needed resurfacing.

<u>Conclusions of Law – Iatan</u>

15. The prudence standard is articulated in the *Associated Natural Gas Case* as follows:

> [A] utility's costs are presumed to be prudently incurred.... However, the presumption does not survive "a showing of inefficiency or improvidence."
>
> . . . [W]here some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent. (Citations omitted).
>
> In the [Union Electric] case, the PSC noted that this test of prudence should not be based upon hindsight, but upon a reasonableness standard:
>
> [T]he company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[269]

16. As stated above, under the prudence standard, the Commission presumes that the utility's costs were prudently incurred.[270] This means that utilities seeking a rate increase are not required to demonstrate their cases-in-chief that all expenditures were prudent.[271]

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[268] *Id.*
[269] *See State ex. Re. Associated Natural Gas v. Public Serv. Comm'n*, 954 S.W.2d 520, 528-529 (Mo. App. W.D. 1997).
[270] *See State ex. Re. Associated Natural Gas v. Public Serv. Comm'n,* 954 S.W.2d 520 (Mo. App. W.D. 1997); *State ex rel. GS Technologies Operating Co. Inc. v. Public Serv. Comm'n,* 116 S.W.3d 680 (Mo. App. W.D. 2003 (citations omitted).
[271] *See Union Electric,* 66 P.U.R.4th at 212.

17. Staff or any other party can challenge the presumption of prudence by creating “a serious doubt” as to the prudence of an expenditure. Once a serious doubt has been raised, then the burden shifts to KCP&L to dispel those doubts and prove that the questioned expenditure was prudent.

18. In a prior case involving a prudence review and construction audit, the Commission stated:[272]

> The Federal Power Act imposes on the Company the “burden of proof to show that the increased rate or charge is just and reasonable.” Edison relies on Supreme Court precedent for the proposition that a utility’s cost are [sic] presumed to be prudently incurred. However, the presumption does not survive “a showing of inefficiency or improvidence.” As the Commission has explained, “utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent . . . However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.”

19. Thus, in the first instance, it is the parties challenging the decisions and expenditures of a utility that have the initial burden defeating the presumption of prudence accorded the utility.[273]

> Under the prudence standard, the Commission looks at whether the utility’s conduct was reasonable at the time, under all of the circumstances. In applying this standard, the Commission presumes that the utility’s costs were prudently incurred.[274]

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[272] *In the Matter of Union Electric Company,* 27 Mo.P.S.C. (N.S.) 183, 193 (1985) (*quoting Anaheim, Riverside, etc. v. Federal Energy Regulatory Commission,* 669 F.2d 779 (D.C. Cir. 1981)) (*citations omitted*).

[273] *State ex rel. Associated Natural Gas Company v. Public Service Commission,* 954 S.W.2d 520, 528-529 (Mo. App., W.D. 1997).

[274] *State ex rel. GS Technologies Operating Company, Inc. v. Public Service Commission***,** 116 S.W.3d 680 (Mo. App., W.D. 2003).

20. Once the presumption of prudence is dispelled, the utility has the burden of showing that the challenged items were indeed prudent.[275]

21. The Commission has adopted a standard of reasonable care requiring due diligence for evaluating the prudence of a utility's conduct.[276] The Commission has described this standard as follows:[277]

> The Commission will assess management decisions at the time they are made and ask the question, "Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?"

22. In the *Associated Natural Gas* case, the Missouri Court of Appeals held that the Staff must provide evidence that the utility's actions caused higher costs than if prudent decisions had been made.[278] Substantive and competent evidence regarding higher costs includes evidence about the particular controversial expenditures and evidence as to the "amount that the expenditures would have been if the [utility] had acted in a prudent manner."[279]

23. In other words, Staff or the other parties must satisfy the following two-pronged evidentiary test to support a disallowance: 1) identify the imprudent action based upon industry standards and the circumstances at the time the decision or action was made; and 2) provide proof of the increased costs caused by KCP&L's imprudent decisions. To meet this standard, a party must provide substantive, competent

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[275] *Associated Natural Gas, supra,* 954 S.W.2d at 528-529.
[276] *Union Electric,* 27 Mo.P.S.C. (N.S.) at 194.
[277] *Id.*
[278] *See Associated Natural Gas*, 945 S.W.2d at 529.
[279] *See id.*

evidence establishing a causal connection or "nexus" between the alleged imprudent action and the costs incurred.

Decision – Iatan

The costs for construction resurfacing, campus relocation for the Iatan 2 Turbine Building, the WSI change order, and the temporary auxiliary boiler shall be excluded from rate base. All other rate base additions shall be included in rate base.

B. Crossroads

Was the decision to add the approximately 300 MW of capacity from Crossroads prudent?

If the decision to add Crossroads was prudent, what is the appropriate valuation of Crossroads?

If Crossroads is included in rate base, should the accumulated deferred taxes associated with Crossroads be used as an offset to rate base?

If Crossroads is included in rate base, should the transmission expense to get the energy from Crossroads to MPS's territory be included in expenses?

If transmission expense is included, should the Commission reflect any transmission cost savings to the Company resulting in its future participation in SPP as a network service customer related to the Crossroads plant be an offset?

Findings of Fact – Crossroads

219. GMO seeks recovery of costs associated with its capacity planning, namely: (1) the construction of three 105 MW combustion turbines at South Harper and a 200 MW system-participation based purchased power agreement ("PPA"); and (2) adding Crossroads Energy Center ("Crossroads") to the MPS generation fleet. Staff,

the Industrials, and Dogwood Energy dispute the prudence of these decisions and their associated costs.

History and Prudence

220. The Crossroads issues have their genesis from GMO's (then known as Aquila, Inc.) anticipation in the late 1990's and early 2000's of the deregulation and decoupling of generation from regulated electric utility operations in Missouri and its participation in the energy market in Missouri and other states through a non-regulated subsidiary, Aquila Merchant Services, Inc.

221. As part of its merchant generation activities, in 2000, Aquila Merchant, with Calpine, built the Aries Plant (now known as Dogwood). The Aries Plant is a natural gas-fired, 585 MW, combined-cycle, intermediate generating facility within Aquila, Inc.'s MPS service area. A five-year PPA with Aquila, Inc. that expired in May 2005 was used as an anchor for building the facility.[280]

222. Aquila Merchant also purchased eighteen 75 MW model 7EA combustion turbines from General Electric and, in 2002, at least three 105 MW model 501D combustion turbines from Siemens-Westinghouse.[281]

223. Aquila Merchant used four of the 75 MW combustion turbines at the facility it built near Clarksdale, Mississippi in 2002—Crossroads.[282] Aquila Merchant sold, at substantial discounts from its cost, three of the 75 MW combustion turbines to unaffiliated entities in 2003. Aquila Merchant released one of the 75 MW combustion turbines back to the manufacturer, and in 2003 installed six of them at the Goose Creek

[280] Ex. GMO 210, p. 91.
[281] Ex. GMO 215, pp. 39, 48.
[282] Ex. GMO 216, p. 4.

Energy Center and the other four at the Raccoon Creek Energy Center, both in Illinois.[283] Aquila Merchant kept the three 105 MW Siemens-Westinghouse combustion turbines it purchased in 2002 intending to install them at the 585 MW, combined-cycle generating facility for a purchased power agreement with GMO after the 5-year purchased power agreement with GMO expired in May 2005. When it could not sell them, they were stored until 2005 when they were installed as regulated units at South Harper to be used for the MPS service area.[284]

224. Aquila Merchant sold both its Goose Creek Energy Center and its Raccoon Creek Energy Center to Union Electric Company d/b/a AmerenUE (now d/b/a Ameren Missouri) at substantially below book value in 2006.[285]

225. The table that follows shows the installed cost per kilowatt of 17 of the combustion turbines Aquila Merchant bought and took delivery of, and the price per kilowatt it received when it disposed of them:[286]

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283 Ex. GMO 215, pp. 47-51.
284 Ex. GMO 215, pp. 39-40.
285 Ex. GMO 215, p. 47.
286 Ex. GMO 215, p. 51; Ex. GMO 262, Staff MPS Accounting Schedules 3-1, 3-2, 6-1 and 6-2.

Installed site	No. of Turbines	Date Installation / Sold	Cost	Capacity	Price per kilowatt
Raccoon Creek **Goose Creek**	4 6	2003 installed 2006 sold to Ameren	$175 million	850,000 kW	**$205.88**
South Harper	3	2001 Purchased 2005 installed	<u>At Dec 31, 2010</u> Plant $120.4 million Reserve $24.4 Net $95.9	315,000 kW	**$382.16**
Crossroads	4	2002 installed 2008 transferred to MPS regulated	<u>At Dec 31, 2010</u> Plant $119.2 million Reserve 32.1 Net $87.1 million Transmission upgrades (intangibles) Plant $22.5 million Reserve 4.4 Net $18.1 million Total Plant $141.7 million Reserve 36.5 Net $105.2 million	300,000 kW	**$427.46**

226. Although every other investor-owned electric utility in Missouri built generation, Aquila, Inc. had a corporate policy not to build regulated generating units that it followed until it built South Harper in 2005.[287] Instead, Aquila, Inc. relied exclusively on purchased power to meet its retail customers' increasing demands for electricity.

[287] Ex. GMO 217, pp. 34 and 39.

227. In 2000, Aquila, Inc. entered into the five-year purchased power agreement for power from the Aries Plant. That agreement, which expired in May 2005, provided for 500 MW of capacity in the summer and 320 MW in the winter.[288]

228. Aquila, Inc. knew in 2000 when it began taking power under the five-year purchased power agreement that it would have to replace that capacity by June of 2005.[289]

229. In 2001, Aquila, Inc. began exploring what options might be available in 2005 to replace the 500 MW of capacity. It did so by issuing a request for proposals ("RFPs") in the spring of 2001 for delivery of energy beginning in June of 2005. Because of changes in the industry, Aquila, Inc. reissued those RFPs in early 2003.[290]

230. Staff has criticized and challenged GMO's[291] capacity planning in rate cases over the past decade. It did so in File Nos. ER-2001-672 and ER-2004-0034, criticizing Aquila, Inc. for entering into the five-year purchased power agreement for power from a 585 MW natural gas-fired combined cycle generating unit built by Calpine and Aquila, Inc.'s affiliate Aquila Merchant Services, Inc., instead of building generation it owned. Staff also criticized Aquila, Inc. in File No. ER-2005-0436, challenging the prudency of how Aquila, Inc. built South Harper in the face of opposition to the siting of that facility and its decision to only install three 105 MW combustion turbines instead of five. And Staff had criticism again in File Nos. ER-2007-0004 and ER-2009-0090,

[288] Ex. GMO 210, p. 91; Ex. GMO 233, p. 4.

[289] Ex. GMO 3601, pp. 3-5 and 8-11. Other capacity issues which will also create pressure for GMO to find new capacity solutions include the expiration of a 75 MW purchased power agreement with the Nebraska Public Power District ("NPPD") in 2014 (Ex. GMO 11, p. 6; and Tr. 4045) coal plant retirements, and integration of intermittent resources such as wind generation (Ex. GMO 3601, pp. 4 and 10-13).

[290] Ex. GMO 210, Appendix 5, Sch. LMM-1,p. 1.

[291] Even when it was known as Aquila, Inc.

taking issue with the prudency of Aquila, Inc./GMO for installing three 105 MW combustion turbines in 2005 instead of five.

231. At Aquila, Inc.'s June 26, 2003, resource planning update meeting with Staff and the Office of the Public Counsel, it presented the results of its analysis of the proposals it received. With the exception of one proposal, the proposals were for purchased power agreements, with the source of the capacity and energy varying among wind, coal, combustion turbines, and combined-cycle units. Aquila, Inc. also disclosed then that one bid for 600 MW of capacity which Aquila, Inc. considered to be "excellent" had been made. By September 10, 2003, however, the bid had been withdrawn and not replaced.[292]

232. On January 27, 2004, only sixteen months before its 500 MW capacity agreement would expire, Aquila, Inc. met with and informed Staff of Aquila, Inc.'s power acquisition process for the following five years. In that meeting GMO presented its preferred/proposed resource plan to build what became South Harper, and enter into three-to-five year purchased power agreements for the balance of its resource needs based on the responses to the spring 2003 request for proposals. Staff responded it was concerned that Aquila, Inc. would become overly dependent on short-term purchased power agreements and needed to evaluate adding baseload generation.[293]

233. At its next resource planning update, on February 9, 2004, Aquila, Inc., based on a twenty-year planning period, disclosed that its least cost resource plan was to build five 105 MW combustion turbines in 2005 and buy a small amount of capacity from the market in 2005, meet load growth with additional market purchases until 2009,

[292] Ex. GMO 210, Appendix 5, Sch. LMM-1 at pp. 1-2.
[293] Ex. GMO 210, Appendix 5, Sch. LMM-1 at p. 2.

when it would build an additional 105 MW combustion turbine and a second in 2010, as well as pursue adding baseload capacity for 2010. Therefore, in February of 2004, about sixteen months before its five-year 500 MW purchased power agreement expired, Aquila, Inc.'s least cost resource plan included building five 105 MW combustion turbines in 2005.[294]

234. At its following semi-annual update to Staff and the Office of the Public Counsel, held on July 9, 2004, GMO disclosed it had entered into an agreement to purchase 75 MW of power from NPPD, but that its least cost plan still included building five 105 MW combustion turbines in 2005, although its preferred plan still was to build three 105 MW combustion turbines in 2005 and rely on purchased power for the balance of its needs. Therefore, in July of 2004, about eleven months before its five-year 100 MW purchased power agreement expired, Aquila, Inc.'s least cost resource plan included building five 105 MW combustion turbines in 2005.[295]

235. After prudently exploring and planning its capacity needs following the expiration of its five-year 500 MW purchased power agreement in May of 2005, GMO elected not to build five combustion turbines, and instead built three 105 MW combustion turbines at South Harper, a site designed for up to six 105 MW combustion turbines, and entered into PPA that included base load capacity in order to diversify its resource portfolio additions. "GMO concluded that it would be prudent to spread the execution and operating risks from the resource additions between building combustion turbines and adding a PPA that contained some level of base load capacity."[296]

[294] Ex. GMO 210, Appendix 5, Sch. LMM-1 at p. 3.
[295] Ex. GMO 210, Appendix 5, Sch. LMM-1 at p. 3.
[296] Ex. GMO 11, p. 4.

236. Staff argues that its adjustments[297] “reflect the continuation of Staff’s position that GMO should have prudently addressed its capacity needs for MPS to replace the Aires PPA when it expired on May 31, 2005.”[298] Notably, Staff’s conclusion is based on the same analysis as that developed and used by the Company in deciding to pursue the three combustion turbine/system-participation PPA.

237. The difference between Staff’s preferred five combustion turbine plan and the Company’s three Combustion turbine/system-participation PPA plan is minimal.[299] Even Staff witness Lena Mantle testifies that she did not believe the cost difference between the Company’s preferred plan and Staff’s five combustion turbine option over 20 years was significant,[300] and that she did not find the Company’s decision based on this difference to be imprudent.[301]

238. Ultimately, the Company did not precisely implement its preferred plan. Based on the 2004 analysis, the preferred plan called for three 105 MW combustion turbines and a 200 MW system PPA. The three combustion turbines were completed in the summer of 2005, but the Company was unable to complete the system PPA. Instead, the Company entered into a 9-year 75 MW base load contract with the Nebraska Public Power District (“NPPD”) and purchased power from Crossroads short-term for the remaining 200 MW.[302]

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[297] The Company denotes the two additional 105 MW combustion turbines Staff would impute to GMO instead of Crossroads as “phantom turbines.”
[298] Ex. GMO 210, p.103.
[299] Ex. GMO 217, Sch. 119.
[300] Tr. 4090.
[301] Tr. 4091.
[302] Ex. GMO 210, Appendix 5, Sch. LMM-1, pp. 1 and 3.

239. After a thorough analysis of available options, the Company determined the 300 MW Crossroads Energy Center was the lowest cost option for meeting its requirements.

240. In August 2008, after the Great Plains Energy acquisition of Aquila, the Crossroads unit was transferred to the regulated books of GMO.[303]

241. In 2010, per the Stipulation and Agreement in GMO's last rate case, GMO conducted a 20-year analysis to determine a preferred plan after reviewing and analyzing the responses from a 2007 Request for Proposals for supply resources.[304] The analysis showed that Crossroads would result in the lowest 20-year net present value of revenue requirements ("NPVRR").

Delivered Natural Gas Prices

242. Historically the prices of natural gas delivered to Crossroads (Clarksdale, Mississippi) have been higher than the prices of natural gas delivered to South Harper (Peculiar, Missouri).[305] More recently, in the first ten months of 2010, the average commodity cost for natural gas shipped to Crossroads was less than gas shipped to South Harper. Moreover, the average delivered cost of natural gas to Crossroads was about half the average delivered cost of natural gas to South Harper.[306] The explanation is that while the commodity prices of natural gas are higher at Crossroads than at South Harper, adding the firm transportation costs to the commodity price for natural gas at South Harper results in a higher natural gas price at South Harper than

[303] Ex. 216, p. 5.
[304] Ex. GMO 11, p. 8.
[305] Ex. GMO 217, p. 43.
[306] Ex. GMO 8, p. 2.

the natural gas price that was paid at Crossroads the past two years—2009 and 2010.[307]

243. One of the benefits of Crossroads over the two turbines at South Harper "is that natural gas shipped to Crossroads typically comes from a different supply region than natural gas shipped to South Harper. This allows the GMO to take advantage of short-term pricing disparities."[308] With Crossroads in the portfolio "the Company can choose to generate electricity from the region with the lower priced natural gas."[309] However, the lower natural gas prices at Crossroads are offset by much higher electric transmission costs, discussed below.[310]

Transmission Cost

244. Staff argues that the cost of transmission to move energy from Crossroads in Mississippi to GMO's service territory justifies, in part, removing Crossroads from GMO's cost of service. The Company argues that the cost of transmission is offset by the lower gas reservation costs.

245. The cost of transmission to move energy from Crossroads to customers served by MPS is a very significant cost that is far greater than the transmission costs for power plants located in the MPS district.[311] The annual energy transmission cost was estimated as $406,000 per month.[312] This is also substantially higher on an annual

[307] Ex. GMO 217, p. 44.
[308] Ex. GMO 8, pp. 4-5.
[309] Ex. GMO 8, p. 5.
[310] Ex. GMO 217, p. 44.
[311] Ex. GMO 217, p.7; Ex. GMO 11, p. 10.
[312] Tr. 4050.

basis than the transmission plant costs for the Aries site where the three South Harper Turbines were originally planned to be installed.[313]

246. This higher transmission cost is an ongoing cost that will be paid every year that Crossroads is operating to provide electricity to customers located in and about Kansas City, Missouri. GMO does not incur any transmission costs for its other production facilities that are located in its MPS district that are used to serve its native load customers in that district. This ongoing transmission cost GMO incurs for Crossroads is a cost that it does not incur for South Harper, and is the cause of one of the biggest differences in the on-going operating costs between the two facilities.

247. It is not just and reasonable to require ratepayers to pay for the added transmission costs of electricity generated so far away in a transmission constricted location. Thus, the Commission will exclude the excessive transmission costs from recovery in rates.

Special Protection Scheme

248. Crossroads faces local (Mississippi) transmission constraints, because the existing lines cannot carry the full load of the plant under certain circumstances.[314] As a result, it is subject to a special protection scheme mandated by the Southwest Power Pool ("SPP").[315]

249. The special protection scheme requires the ramp down of the output of one of its four combustion turbines if a particular one of the two transmission lines used to move energy from Crossroads to MPS becomes unavailable. This risk of capacity

[313] Ex. GMO 217, p. 7.
[314] Tr. 4050.
[315] Ex. GMO 3601, p. 8; Tr. 4051, Ex. GMO 3603, p. 14 and pp. 31-33; Tr. 4125.

loss is one of the transmission-related risks of Crossroads. GMO's MPS retail customers should bear neither the costs nor risks associated with the transmission limitations in getting electricity from Crossroads to MPS.[316] In determining that transmission costs will be excluded, the Commission has sufficiently addressed these risks and costs.

Plant Managerial Oversight

250. Staff also expressed concern with GMO's ability to provide appropriate management oversight of a plant located in Mississippi.

251. To reduce transmission losses and outages power plants are built close to where the electricity is needed—close to customers.[317] Crossroads, however, is located over 9 hours and 525 miles from Kansas City, Missouri.[318]

252. No KCPL employees operate Crossroads, rather, GMO has contracted with the City of Clarksdale, Mississippi to operate Crossroads under an agreement with the Clarksdale Public Utilities Commission.[319]

253. A tolling agreement for the capacity and energy of the plant was originally held by MEP Clarksdale Power, LLC, which became Aquila Merchant Services, which assigned the agreement to Aquila, Inc., which is now GMO. The agreement runs through 2032 with a right to extend up to ten more years. GMO also holds a purchase

[316] Ex. GMO 233, pp. 5-6.
[317] Ex. GMO 217, p. 42.
[318] Ex. GMO 217, p. 42
[319] Ex. GMO 31, p. 2.

option, but does not intend to exercise it because the advantages of tax exempt financing would be lost.[320] The municipal ownership facilitated tax exempt financing.[321]

254. GMO witness Rollison identifies the agreement as a "Generation, Operations and Maintenance Agreement" between Clarksdale and GMO. The agreement "permits GMO to receive the output of the plant in exchange for payments that cover fixed and variable costs to produce the electrical output, as well as to maintain and operate the facility."[322] The Generation Agreement between the Clarksdale Public Utilities Commission and GMO states that "GMO has the right to review and approve the annual Operating Plan which constitutes a comprehensive and detailed plan for operating the facility for [the] coming two-year period."[323] In addition, GMO has the authority to review and approve the annual operating plan and budget, as well as to audit costs and inspect the facility.[324]

255. GMO is supposed to pay Clarksdale an "Availability Incentive Bonus Fee" for increased availability of generation and has the right to invoke an "Availability Liquidated Damages" clause for reduced availability, although there is no evidence as to whether or how often such clauses have actually been applied.[325] There would be no comparable internal fees if GMO owned and operated the plant itself.[326]

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[320] Ex. GMO 3601, p. 7-8; Ex. GMO 31, p. 2; Ex. GMO 42, p. 55; Tr. 4053 and 4059.
[321] Tr. 4053.
[322] Ex. GMO 31, p. 2-3.
[323] Ex. GMO 31, p. 3.
[324] Ex. GMO 31, p. 3; Tr. 4078-79.
[325] Tr. 4076.
[326] Tr. 4076.

256. The City agrees to protect GMO from various risks by means of an indemnification clause.[327]

257. With the exceptions of the Wolf Creek nuclear plant (of which KCPL is a minority owner) and the Jeffrey Energy Center (of which GMO is a minority owner), KCPL employees operate all other KCPL and GMO plants.[328]

258. GMO also has ownership interest in other generating facilities operated and managed by non-GMO employees. It is not uncommon in the industry to have plants run by someone other than the owner. For example, KCP&L runs plants for Westar, Empire, GMO and MJMEUC. Further, other utilities run Wolf Creek and Jeffrey Energy Center, of which KCP&L and GMO, respectively, are minority owners.

259. GMO personnel have visited the site six times over the past two years.[329]

260. The ability of GMO to provide managerial oversight to the plant is only slightly hampered by the long distance location of the plant facilities.

261. The management oversight has not proven to be a problem and therefore is not a reason for denial of recovery.

Ultimate Finding Regarding Prudence of Crossroads

262. Considering the costs involved, the fact that this was an affiliate transaction rather than an arms-length transaction, the relative reliability of transmission, the excessive costs of that transmission, the reduced costs for natural gas and the alternative supply source, the distance of the power in location to the customers served, and the other facts set out above, the Commission finds that the decision not to

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[327] Ex. GMO 31, p. 4.
[328] Tr. 4054, 4075 and 4079.
[329] Ex. GMO 3601, pp. 4-5; Tr. 4052-54; and Tr. 4078-79.

build two more 105 MW combustion turbines at South Harper was not imprudent. In addition, the decision to include Crossroads in the generation fleet at an appropriate value was prudent with the exception of the additional transmission expense, when other low-cost options were available. Paying the additional transmission costs required to bring energy all the way from Crossroads and including Crossroads at net book value with no disallowances, is not just and reasonable and is discussed in detail below.

Valuation of Crossroads

263. With regard to the valuation of Crossroads, Staff's primary recommendation is that Crossroads should be disallowed in its entirety.[330] It argues alternatively that if the Commission decides to allow Crossroads in GMO's cost of service, then the value of Crossroads for ratemaking purposes is $51.6 million or another alternative of $61.8 million. GMO believes its valuation of Crossroads at $104 million is appropriate.[331]

264. GMO argues that because it did not dismantle the plant and it was able to obtain transmission from Crossroads to GMO, the value of the plant was $94.75 million, assuming that $20 million in transmission upgrades would be required. GMO was ultimately able to obtain transmission service with only a minimal transmission investment of $145,000, bringing its estimated value of Crossroads to $114.60

[330] Ex. GMO 210, p. 92.
[331] Ex. GMO 12, p. 3.

million.[332] This value is more than the net book value of $104 million GMO has requested for ratemaking treatment in this case.[333]

265. At December 31, 2010, the plant and transmission facilities values for Crossroads were:[334]

Plant in Service	$119.1 million
Depreciation Reserve	$ 32.1 million
Net Plant	$ 87.0 million
Transmission Rights -- Intangible	$ 22.5 million
Reserve	$ 4.4 million
Net Transmission	$ 18.1 million
Total Crossroads Plant	$141.7 million
Reserve	$ 36.5 million
Net Plant	$105.2 million

266. Aquila, Inc. attempted to sell Crossroads, but was unable to sell it.[335] It follows that, absent a write-down which GMO has not taken, the market value of Crossroads is less than its booked value.

267. In February 2007, Great Plains Energy announced that it was seeking to acquire Aquila, Inc. Given several recent divestitures by Aquila, Great Plains acquisition amounted to simply the Missouri regulated electric operations as well as the Crossroads Energy Center. Over the next several months, Great Plains made three separate filings with the Securities Exchange Commission regarding the "fair value" of the Crossroads unit. As Great Plains indicated:

> The preliminary internal analysis indicated a fair value estimate of Aquila's non-regulated Crossroads power generating facility of approximately $51.6 million. This analysis is significantly affected by assumptions regarding the current market for sales of units of similar capacity. The

[332] Ex. GMO 12, p. 3.
[333] Ex. GMO 12, p. 3.
[334] Ex. GMO 262, Schs. 3-1, 3-2, 6-1 and 6-2.
[335] See the specifics regarding bids in the "Highly Confidential" Information at Ex. GMO 216, p. 13.

> $66.3 million adjustment reflects the difference between the fair value of the combustion turbines at $51.6 million and the $117.9 million book value of the facility at March 31, 2007. Great Plains Energy management believes this to be an appropriate estimate of the fair value of the facility.[336]

The valuations disclosed by Great Plains to the Securities Exchange Commission were made under oath.

268. GMO claims that the fair market value of Crossroads is established by an RFP conducted in March 2007, prior to the SEC disclosures. GMO postulates that, the responses to this RFP, demonstrate that fair market value is comparable to the proposed net book value. GMO fails to explain, however, given the alleged results of the RFP, why it announced to the Securities Exchange Commission, mere months later, that "fair value" was only $51.6 million.

269. GMO's assertion is also inconsistent with real world evidence as to the diminution in value experienced by these deregulated generating assets. The evidence indicates that, following the crash of the deregulated electric market and the bankruptcy of Enron, many deregulated generating assets, including combustion turbines identical to those in service at Crossroads, experienced a significant devaluation.[337] Specifically, the evidence indicates that Aquila sold General Electric combustion turbines, identical to those installed at Crossroads in 2006. At that time, Aquila also sold its ownership interest in Raccoon Creek and Goose Creek in Illinois to AmerenUE. Given the deterioration in the deregulated market, Aquila took a write-off, from net book value, of

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[336] Ex. GMO 216, p. 12 (citing to Great Plains Energy & Aquila Joint Proxy Statement / Prospectus, filed with the SEC on May 8, 2007, at page 175).
[337] Ex. GMO 215, p. 58; Ex. GMO 217, p. 6.

$99.7 million.[338] Aquila sold other General Electric turbines to Nebraska and Colorado utilities.[339] Again, the price received by Aquila was significantly affected by the deterioration in the deregulated energy market.[340]

270. These sales by Aquila, of combustion turbines identical to those installed at Crossroads, are not only a good indicator of the fair market value, but also clearly show that the fair market value of these General Electric combustion turbines was significantly below the net book value.

271. When conducting its due diligence review of Aquila's assets for determining its offer price for Aquila, GPE would have considered the transmission constraints and other problems associated with Crossroads.[341] It is incomprehensible that GPE would pay book value for generating facilities in Mississippi to serve retail customers in and about Kansas City, Missouri. And, it is a virtual certainty that GPE management was able to negotiate a price for Aquila that considered the distressed nature of Crossroads as a merchant plant which Aquila Merchant was unable to sell despite trying for several years. Further, it is equally likely that GPE was in as good a position to negotiate a price for Crossroads as AmerenUE was when it negotiated the purchases of Raccoon Creek and Goose Creek, both located in Illinois, from Aquila Merchant in 2006.

272. 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.

[338] Ex. GMO 215, p. 51.
[339] Ex. GMO 215, p. 48.
[340] Ex. GMO 215, p. 48.
[341] Ex. GMO 216, p. 7.

Four of those eighteen were installed at Crossroads. The turbines sold at an average installed cost of $205.88 per kW.[342] 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.

273. Aquila Merchant purchased a total of 21 combustion turbines. It offered three of them at below its cost to several entities, including KCPL, in 2002 before it stored them. These turbines were eventually installed at South Harper and are in MPS's rate base at a discount from what Aquila Merchant paid for them. Aquila merchant also sold thirteen other combustion turbines below its cost to buy them as follows:[343]

- Goose Creek—6 General Electric turbines sold to AmerenUE in 2006.
- Raccoon Creek—4 General Electric turbines sold to AmerenUE in 2006.
- Utility in Beatrice, Nebraska – 2 General Electric turbines sold in 2002.
- Utility in Colorado – 1 General Electric turbines sold in 2002.

274. All the above generating assets are now serving customers at prices consistent with the turbine market after the Enron collapse.[344] Even Aquila wrote-down from what Aquila Merchant paid for them the combustion turbines it installed at South Harper to comply with the Commission's affiliated transaction rule.[345] Yet, in this case GMO is seeking to include the full value of Crossroads on its books, without a write-down, in MPS's rate base.

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342 Ex. GMO 215, pp. 50-51.
343 Ex. GMO 216, pp. 47 and 49.
344 Ex. GMO 215, pp. 48-51.
345 Ex. GMO 216, pp. 17-18.

275. Considering the depressed market as exhibited by the sale of similar turbines to Ameren, and the valuation of these assets reported to the SEC by GPE, the Commission finds that $61.8 million is an accurate reflection of the fair market value of Crossroads as required by the affiliate transaction rule as of July 14, 2008.

Deferred Income Taxes

276. Since Crossroads became part of the non-regulated operations of Aquila Merchant in 2002, deferred income taxes accumulated.[346] In all instances, KCPL and GMO use deferred income taxes relating to regulated investment assets as an offset (reduction) to rate base, except now for Crossroads.[347] It is GMO's position that since Crossroads was not part of its regulated operations when those deferred taxes were created, they should not be used as an offset to MPS's rate base now. If the Commission authorizes GMO to rate base Crossroads in this case, then it is Staff's position that all the accumulated deferred income taxes associated with Crossroads should be offset against rate base attributable to MPS.

277. The accumulated deferred taxes associated with Crossroads should be applied as an offset to MPS's rate base.[348]

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[346] Ex. GMO 210, p. 109.
[347] Ex. GMO 210, p. 109.
[348] Ex. GMO 210, p. 110.

Dogwood

278. Dogwood Energy, LLC (Dogwood) is both a retail power customer of GMO and a wholesale power supplier to GMO.[349] As a customer, Dogwood supported Staff's disallowance of Crossroads and imputation of two phantom turbines in order "to protect GMO's retail customers, including Dogwood, against exorbitant rates."[350] With regard to its interest as a wholesale supplier to GMO, Dogwood suggests that the Commission discourage GMO from using the Crossroads facility and instead replace it with a local unit -- such as Dogwood's combined cycle facility.[351]

279. Dogwood argues that the cost of natural gas to Dogwood is cheaper than to Crossroads, transmission service to Crossroads is problematic and the Company's resource planning analyses are flawed because the Company failed to contact Dogwood. In addition, Dogwood makes a number of legal challenges to inclusion of Crossroads in rates.

280. Contrary to Dogwood's arguments, the testimony and evidence presented in this case demonstrate that the delivered cost of natural gas is cheaper to Crossroads than to Dogwood, however that cost is offset by the transmission costs. In addition, GMO's firm transmission service is reliable and sufficient and GMO has repeatedly considered Dogwood in its resource planning decisions, including the Company's recent 2010 Stipulation 8 Capacity Study.

281. Dogwood has not been the lowest cost resource option.

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[349] Ex. GMO 3601, p. 3.
[350] Ex. GMO 3601, p. 4.
[351] Ex. GMO 3601, p. 4.

Conclusions of Law – Crossroads

24. This issue concerns the appropriate valuation to place on the Crossroads generating unit recently devoted by GMO to serving its ratepayers. The Supreme Court has held that the utility must be permitted to earn a return on the "fair value" of the property devoted to the public convenience.

> The corporation may not be required to use its property for the benefit of the public without receiving just compensation for the services rendered by it. . . . We hold, however, that the basis of all calculations as to the reasonableness of rates to be charged by a corporation . . . must be the ***fair value of the property being used by it for the convenience of the public***. What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience. On the other hand, what the public is entitled to demand is that no more be extracted from it than the services rendered by it are reasonably worth.[352]

25. The Commission's authority to establish the valuation of an electric corporation's plant has also been memorialized in Section 393.230:

> ***The commission shall have the power to ascertain the value of the property of every . . . electrical corporation . . . in this state and every fact which in its judgment may or does have any bearing on such value.*** The commission shall have power to make revaluations from time to time and to ascertain all new construction, extensions and additions to the property of every . . . electrical corporation. (emphasis added).

26. Recognizing that Crossroads was transferred from a non-regulated affiliate to the Missouri regulated operations, the Commission's affiliate transaction rule is implicated. The affiliate transaction rule, as it applies to the immediate issue, provides that the purchase of "goods or services" from an affiliate shall be "the ***lesser*** of: (a) fair market price; or (b) the fully distributed cost."[353]

[352] *Smyth v. Ames*, 169 U.S. 466, 546-547 (1898) (emphasis added).
[353] 4 CSR 240-20.015(2)(A) (emphasis added).

27. The Commission concludes that if included in rate base at a fair market value, rather than the higher net book value paid to its affiliate, and except for the additional cost of transmission from Mississippi to Missouri, the Company's 2004 decision to pursue the construction of three 105 MW combustion turbines at South Harper and pursue a 200 MW system-participation based purchased power agreement, and the Company's decision to add the Crossroads generating facility to the MPS generation fleet were prudent and reasonable decisions.

28. The Commission rejects Staff's adjustment to disallow the recovery of the entirety of Crossroads in the Company's cost of service and instead recover the cost of the "phantom turbines." The Commission concludes, however, that GMO is requesting the Commission value these turbines based on that overly high valuation (net book value) and that Crossroads includes significantly higher transmission costs it will incur over the life of Crossroads. The Commission concludes that Crossroads should be included in rate base at a value of $61.8 million based on the average installed dollar per kilowatt basis AmerenUE paid for the combustion turbines at Raccoon Creek and Goose Creek.

29. In addition to the valuation, the Commission concludes that but for the location of Crossroads customers would not have to pay the excessive cost of transmission. Therefore, transmission costs from the Crossroads facility, including any related to OSS shall be disallowed from expenses in rates and therefore also not recoverable through GMO's fuel adjustment clause ("FAC").

30. The Commission concludes deferred taxes shall be an offset to rate base.

31. The Commission rejects the Industrials' position to the extent and for the same reasons set out in response to Staff's arguments.

<u>Decision – Crossroads</u>

The Commission rejects Staff's adjustment to disallow the recovery of Crossroads in the Company's cost of service and replace it with the cost of two "phantom turbines." The Commission also rejects GMO's inclusion of Crossroads in rate base at its net book value. The Commission determines that given Great Plains' statements to the Securities Exchange Commission shortly before the transfer of the Crossroads unit to the Missouri regulated operations, as well as the arms-length sale of other General Electric combustion turbines by Aquila, that the fair market value of Crossroads at the time of transfer (August 2008) was $61.8 million. Given the subsequent 32 months, the fair market value of Crossroads for purposes of establishing rate base in this case should also reflect 32 months of depreciation on that unit.

The Commission further determines that it is not just and reasonable for GMO customers to pay the excessive cost of transmission from Mississippi and it shall be excluded. Finally, deferred income taxes shall also be an offset to rate base.

<u>C. Jeffrey FGD Rebuild Project</u>

Should the Jeffrey Rate Base Additions be included in rate base in this proceeding?

Should the Commission presume that the costs of the Jeffrey Rate Base Additions were prudently incurred until a serious doubt has been raised as to the prudence of the investment by a party to this proceeding?

Has a serious doubt regarding the prudence of the Jeffrey Rate Base Additions been raised by any party in this proceeding?

Should the Company's conduct be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the Company had to solve its problem prospectively rather than in reliance on hindsight? ("prudence standard")?

Has GMO demonstrated that it properly managed these complex projects and properly managed matters within its control?

Findings of Fact – Jeffrey FGD Rebuild Project

282. The Jeffrey Energy Center ("JEC") is a coal-fired electric generating facility consisting of three 720 MW units located in St. Marys, Kansas. [354] GMO owns 8% of the JEC facility for a total of 172.8 MW, which is assigned to MPS. Westar Energy is the operating partner who owns the remaining 92%.[355] Westar is also the primary constructor of this project.

283. In 2004, the U.S. Environmental Protection Agency (EPA) served a Notice of Violation at the JEC, identifying the need for compliance with new environmental regulations.[356] To avoid civil penalties, Westar decided to rebuild the cold-side electrostatic precipitators for particulate removal and the limestone-based wet flue gas desulfurization ("FGD") systems, or "scrubbers" on each unit.[357] GMO agreed with Westar's decision to rebuild the scrubbers on all three JEC units.[358]

284. Powerplant Maintenance Specialists, Inc. ("PMSI") was the largest vendor on the Jeffrey FGD Rebuild Project and it was the general construction work

[354] Ex. GMO 210, p. 42, ll. 11-12.
[355] Ex. GMO 210, p. 42, ll. 12-14.
[356] Ex. GMO 210, p. 42, ll. 20-22.
[357] Ex. GMO 210, p. 42, ll. 15-17, 21-22.
[358] Ex. GMO 210, p. 43, l. 1.

contractor.[359] PMSI's initial contract amount is confidential,[360] but was originally a fixed price contract without a performance bond.[361] GMO's witness, Leonard R. Ruzicka, testified on cross-examination during an *in camera* portion of the hearing as to the reasons that PMSI did not have a performance bond.[362] While Westar and GMO did not require PMSI to obtain a performance bond, they required other contractors on the Jeffrey FGD Rebuild Project to obtain a performance bond.[363]

285. Burns & McDonnell was hired as the owners' engineer for the Jeffrey FGD Rebuild Project.[364] Burns & McDonnell provided monthly status reports that addressed project concerns, scheduling, and budget.[365] Monthly status reports and cost reports provided by Westar were reviewed and monitored by GMO for prudence and reasonableness.

286. In this proceeding, Staff is proposing a prudence disallowance of $59,110,980, the total cost of the project of which GMO's 8% share is $4,831,649.

287. Staff's first argument is that: "Westar imprudently contracted with a vendor whose financial instability and poor performance report resulted in additional costs to the project."[366] Secondly, Staff argues that "It was unreason-able of Westar and GMO not to require PMSI to obtain a performance bond,

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[359] Ex. GMO 210, p. 44, ll. 9-10.
[360] Ex. GMO 210, p. 44, ll. 11-12.
[361] Tr. 4252, ll. 12-14.
[362] Tr. 4282, ll. 12-18.
[363] Ex. GMO 210, p. 45, ll. 30-31; *See* Ex. GMO 210, Appendix 3, Schs. 6, 7 and 8.
[364] Ex. GMO 230, p. 44, ll. 14-15.
[365] Ex. GMO 230, p. 44, ll. 15-16.
[366] *Staff's Initial Brief of Issues Specific to KCP&L Greater Missouri Operations Company* at 44.

and this failure to require a performance bond exposed GMO to inappropriate, unreasonable and unnecessary level of financial risk, risk that materialized."[367] Third, Staff argues that: "Westar failed to conduct proper due diligence when evaluating PMSI as a potential contractor." Staff also criticizes Westar for not applying the Federal Acquisition Regulations.[368] Finally, Staff criticized Westar for failing to seek liquidated damages against PMSI.[369] For the reasons stated below, the Commission finds that none of Staff's arguments and criticisms of Westar's actions are well founded.

288. Mr. Terry S. Hedrick, KCP&L's Director of Supply Engineering, explained at length the reasons why Westar and GMO hired the contractor and did not require the contractor to obtain a performance bond. Much of the information was provided as confidential information. However, the contractor's bid was substantially lower than competing bids, and it made economic sense to accept the bid even though the contractor was unable to obtain a performance bond.

289. Mr. Leonard Ruzicka, an expert in construction law, was retained by KCP&L to review documents and interview individuals as necessary to determine the appropriateness of the awarding of a contract to PMSI for the general construction work on the rebuild of the scrubber systems on the three units of the Jeffrey Energy Center coal-fired generating station. Mr. Ruzicka is a partner in the law firm of Stinson Morrison Hecker LLP and previously had 20 years experience as a Senior Vice President and General Counsel for Fru-Con Corporation, a large international company

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[367] Staff Initial Br., pp. 47-48; *See also,* Ex. GMO 210, pp. 42-47; Ex. GMO 21, p. 3.
[368] Staff Br., pp. 48-49.
[369] Staff Br., p. 50.

engaged in construction, engineering and real estate development.[370] He was also retained to review the testimony of Mr. Keith Majors and give his assessment of the opinions expressed by Mr. Majors in that testimony.

290. Mr. Ruzicka, conducted an independent review of the facts and circumstances surrounding this project. He concluded that Westar/GMO had acted appropriately and reasonably in its decision to award the general construction contract to PMSI.[371] Mr. Ruzicka also explained the reasons why it was appropriate to award the contract as Westar/GMO did, based upon the facts and circumstances that were known at the time. Much of the information was provided as confidential information, but the Commission finds that Mr. Ruzicka's review substantiates the prudence of Westar's decision to retain PMSI.

291. The record demonstrates that Westar performed reference checks on prior work performed by PMSI as well as obtained reports from Dun & Bradstreet.[372] In addition, Westar conducted an extensive evaluation of PMSI and was aware of the fact that it could not obtain a performance bond due to its financial condition.[373] However, given the substantial difference in the PMSI bid and the next lowest bid (which would have a bonding cost in addition to the bid), the Commission finds that it was reasonable and prudent for Westar to proceed with the acceptance of the PMSI bid without a performance bond.[374]

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[370] Ex. GMO 36, p. 1; Tr. 4271-72, 4341.
[371] Ex. GMO 36 (NP), pp. 2-5.
[372] Ex. GMO 230, p. 37.
[373] Ex. GMO 21 (HC), p. 3.
[374] Tr. 4356-47.

292. Staff also criticizes Westar for not applying the Federal Acquisition Regulations which Staff admits do not have any applicability to private industry.[375] In addition, Staff criticizes Mr. Ruzicka for not following "any auditing standards when reviewing the work related to PMSI, thus creating serious concerns to the value of his opinion testimony."[376] The Commission finds that it takes more than "auditing" expertise to judge the prudence of construction project decisions. Mr. Ruzicka is an experienced construction law expert, and did not conduct an audit. Instead he reviewed the prudence of the decisions made by Westar, based upon extensive documentary evidence and interview with Westar personnel. Ultimately, he concluded that Westar and GMO were indeed prudent in their decision-making related to the Jeffrey Energy Center FGD Rebuild Project.[377] The Commission finds the testimony of Mr. Ruzicka to be persuasive.

293. Staff asserts that "Mr. Ruzicka testified that PMSI could easily have been replaced."[378] However, on redirect examination, Mr. Ruzicka explained his answer and indicated that it would have been very costly to replace the contractor at that point in the project.[379] Also, as Mr. Ruzicka explained, there was no basis for asserting a claim for liquidated damages, and Staff's criticism was incorrect.[380]

[375] Staff Br. at 48-49.
[376] Staff Br. at 49; *citing* Tr. 4336.
[377] Ex. GMO 36 (NP), pp. 2-5.
[378] Staff Br. at 49.
[379] Tr. 4343.
[380] Tr. 4349-52; *See also* Tr. 4266; 4356-57).

Conclusions of Law – Jeffrey FGD Rebuild Project

32. The Federal Acquisition Regulations are not applicable to private industry.[381]

33. Based upon the competent and substantial evidence in the record, the Commission concludes that the JEC additions were prudent and should be included in rate base in this proceeding. The Commission concludes that Staff's proposed disallowance is based upon hindsight, is unreasonable and not supported by competent and substantial evidence. The Commission will therefore reject Staff's proposed prudence disallowance.

Decision – Jeffrey FGD Rebuild Project

The Commission determines that the Jeffrey Energy Center additions were prudent and should be included in rate base in this proceeding. The Commission further determines that Staff's proposed prudence disallowance is rejected.

D. Demand-Side Management

a. Should DSM investments be included in rate base in this proceeding?

b. How should DSM amortization expense be determined in this case?

i. Should DSM programs be expanded if the current DSM portfolio does not meet the Missouri Energy Efficiency Investment Act's (MEEIA) goal of achieving all cost-effective demand-side savings?

[381] Ex. GMO 260, § 9.104-1.

ii. Should the amortization period for the energy efficiency regulatory asset account be shortened from 10 years to 6 years?

iii. Should the shortening of the amortization period be contingent on the continuation and/or expansion of the DSM portfolio?

c. Should the Company be required to fund DSM programs at the current level?

d. Should KCP&L be required to make a compliance filing with the Commission regarding MEEIA legislation as proposed by Staff?

Findings of Fact – Demand-Side Management

294. In KCP&L's last Chapter 22 Electric Utility Resource Planning filing,[382] KCP&L's adopted preferred integrated resource plan (IRP) included five residential DSM programs and four commercial and industrial programs.[383]

295. These programs are in addition to KCP&L's Energy Optimizer and MPower programs that it implemented as part of its Experimental Regulatory Plan (ERP or "Regulatory Plan").[384]

296. As part of GMO's Chapter 22 compliance filing,[385] GMO's adopted preferred IRP included DSM programs.[386]

297. Demand Side Management (DSM) programs introduced in the early years of KCP&L's five-year regulatory plan are nearing their expiration dates.[387]

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[382] File No. EE-2008-0034.
[383] Kansas City Power & Light Integrated Resource Plan, File No. EE-2008-0034, Book 1 of 2, Volume 5: Demand-Side Resource Analysis, pp. 54 through 69.
[384] *See* File No. EO-2005-0329; Ex. KCP&L 239, p. 6.
[385] File No. EE-2009-0237.
[386] Ex. GMO 240, p. 14.
[387] Ex. KCP&L 603, Sch. AB2010-1R.

298. The timing of the conclusion of the regulatory plan and the anticipated implementation of the rules resulting from the Missouri Energy Efficiency Investment Act (MEEIA)[388] create a period of time in which KCP&L and GMO will not have guidance from the Commission with regard to appropriate DSM investment or energy savings targets.[389]

299. This gap could be relatively lengthy, possibly years.[390] The Company acknowledged the uncertainty of this gap.[391]

300. Many of the current DSM programs "have met or are exceeding their five-year savings goals" and in some cases "have met or exceeded their performance and participation goals."[392] KCP&L has "met and exceeded the expectations established in the Regulatory Plan. . . . [T]hrough June 30, 2010 the budget for all Company demand-side programs is $24,001,009 and the actual total expenditures through this period are $27,442,517 . . . ."[393]

301. DSM programs need time to raise customer awareness through promotional campaigns and develop partnerships with trade allies. If programs are curtailed, there would be a loss of experience developed by KCP&L and GMO over the past five years.[394]

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[388] Section 393.1075, RSMo.
[389] Ex. KCP&L 601, p. 2.
[390] Ex. KCP&L 601, p. 4; Ex. GMO 601, p. 4.
[391] Tr. 3542; Tr. 3539-3540.
[392] Ex. KCP&L 603, p. 5 and as shown on Mr. Bickford's highly confidential rebuttal schedule AB2010-2R, Ex. KCP&L 604 HC.
[393] Ex. KCP&L 210, p. 127. *See also*, Ex. KCP&L 56, p. 4.
[394] Ex. KCP&L 603, p. 6-7.

302. "[A]ll of the evidence suggests that customer interest in these programs has increased since 2005, and there is no evidence to suggest that customers will become less interested in realizing the benefits that these programs offer."[395] For instance, participation in KCP&L's Home Performance with Energy Star program increased from 27 homes in the second quarter of 2009 to 718 homes at the end of the third quarter of 2010.

303. The Companies are currently continuing their DSM programs contained in their tariffs.[396]

304. During its Customer Programs Advisory Group (CPAG) meetings throughout 2010, KCP&L stated to Staff that it had stopped processing new customer applications for its voluntary large customer MPower demand response program.[397] During the similar DSM Advisory Group meetings held for GMO in 2010, GMO also made statements regarding the curtailing of current DSM programs and delaying implementation of planned DSM programs.[398] In those statements and at the hearing, both KCP&L and GMO expressed a position to slow spending for the programs.[399]

305. Both companies, as well as the ratepayers, stand to benefit from continuing efforts to achieve more DSM programs and improved DSM penetration. The companies acknowledge this fact.[400] And in the case of KCP&L, increasing DSM

[395] Ex. KCP&L 603, p. 6.
[396] Ex. KCP&L 210, p. 126-30; Ex. KCP&L 239 at p. 2.
[397] Ex. KCP&L 239, p. 6.
[398] Ex. GMO 240, p. 12.
[399] Tr. 3539-3540; Tr. 3571.
[400] Ex. KCP&L 239, p. 6-7, Ex. GMO 240, p .15.

funding is preferred to curtailing program spending when evaluating the need for additional supply-side resources over the next 25 years.[401]

306. Under the existing cost recovery mechanism, KCP&L first funds the DSM programs and the costs are placed into a regulatory asset account for consideration of recovery in the next rate case. Assuming the DSM costs are determined to be recoverable, those costs are then amortized over a ten-year period without the inclusion in rate base.

307. KCP&L is willing to continue the Customer Program Advisory Group (CPAG) through the bridge periods and to extend CPAG or a similar collaborative to GMO through the same period.[402]

308. Staff recommends the Commission accept its ratemaking calculations for DSM deferrals and AFUDC returns in Staff Adjustments E-144.4 through E-144.7, and E-144.8 through E-144.11.[403] Staff's recommendations included annual amortizations (10-year deferral period) for the following DSM vintage deferrals:[404]

DSM deferral	Case	Amount
Vintage 1	ER-2006-0314	$239,666
Vintage 2	ER-2007-0291	$448,624
Vintage 3	ER-2009-0089	$193,663
Vintage 4	ER-2010-0355	$1,810,223

[401] Ex. KCP&L 239, p. 7.
[402] Tr. 3543.
[403] Ex. KCP&L 225, as updated in true-up.
[404] Ex. KCP&L 225, as updated in true-up.

309. Staff calculated the total unamortized balance of DSM Vintages 1 through 4 as $24,368,761 as of December 31, 2010.[405] The AFUDC rate Staff applied to this unamortized DSM balance was 3.46%, and is KCP&L's December 2010 AFUDC rate.[406] Under Staff's calculations, the AFUDC return amount totals $843,159, for a total increase in revenue requirement from DSM deferrals of approximately $3.5 million.[407]

310. Staff recommends that the existing levels of DSM investments should be mandated by the Commission to continue and the existing cost recovery mechanism should be maintained.[408]

311. In its adjustments Staff nets unrelated issues with DSM program costs.[409] Staff includes negative costs against the unamortized balance of DSM program costs for purposes of computing an annual amortization and return. These negative costs are those that the Commission has previously ordered to be returned to ratepayers over ten years and include excess margins on off-system sales ("OSS") and net reparations from the litigation of Montrose coal freight rates before the Surface Transportation Board ("STB"), but are unrelated to DSM Program costs.

312. The Commission ordered in prior cases that the carrying costs for the excess margins on OSS would be established at LIBOR plus 32 basis points and that this interest would be included in the unamortized balance of excess OSS margins for amortization over ten (10) years. The Commission also prohibited rate base recognition

[405] Ex. KCP&L 225, as updated in true-up.
[406] Ex. KCP&L 225, as updated in true-up.
[407] Ex. KCP&L 225, as updated in true-up.
[408] Ex. KCP&L 210, pp. 126-30; Ex. KCP&L 239, p. 2.
[409] Ex. KCP&L 210, pp. 131-37; Ex. KCP&L 226, p. 63.

for the unamortized balance of net reparations from the litigation of Montrose coal freight rates before the STB and did not otherwise order carrying costs.

313. Staff could set up and keep track of these separate cost items, but believed this would be cumbersome and inefficient.[410]

314. Staff also recommends continuing the ten-year amortization for DSM expenses incurred after the end of the regulatory plan.

315. To apply a ten-year amortization to DSM expenses incurred after the end of the regulatory plan for KCP&L and after the test year in GMO's rate case would be a disincentive to KCP&L and GMO to invest in demand side programs.[411]

316. A temporary adjustment from 10 years to 6 years amortization for new and ongoing DSM expenses incurred during the "gap period" until MEEIA rules are fully implemented would reduce the disincentive.[412]

317. An adjustment from 10 years to 6 years amortization for new and ongoing DSM expenditures would also make the Companies' cost recovery opportunities more consistent with Ameren Missouri's DSM program cost recovery agreed to by the parties and approved by the Commission in File No. ER-2010-0036.[413]

318. Netting the DSM regulatory asset account amortization with three unrelated accounts is complex and confusing and causes an inaccurate result.[414]

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[410] Ex. KCP&L 226, p. 63.
[411] Ex. KCP&L 55, p. 5-6; Ex. KCP&L 605, pp. 4-5.
[412] Ex. KCP&L 55, pp. 5-6; Ex. KCP&L 605, p. 4-5.
[413] Ex. GMO 601, p. 10.
[414] Ex. KCP&L 64 p. 6-18.

319. Staff's netting calculation may put DSM cost recovery at risk or it may cause the perception of putting DSM cost recovery at risk. Either of those effects could be a disincentive to future DSM spending by utilities.[415]

320. KCP&L recommends that DSM expenses referred to as "Vintage 4," be amortized for six years rather than for ten years.[416]

321. Neither KCP&L nor GMO has recommended in any substantial detail in these rate proceedings what they consider to be an appropriate cost recovery mechanism.[417] In fact, in their direct filings both KCP&L and GMO only requested the continuation of their current cost recovery mechanisms.[418] In their brief, however, they state that for the purposes of this case, KCP&L has proposed that the cost recovery mechanism should be consistent with the recent *Order Approving First Stipulation and Agreement* in the AmerenUE rate case, File No. ER-2010-0036 (March 24, 2010).[419] This would change KCP&L's amortization period for the DSM regulatory assets from ten years to six years, and include the unamortized balance in rate base for actual expenditures booked to the DSM regulatory asset up through the period of December 31, 2010.[420] The six year amortization period would be applied to DSM program expenditures referred to by Staff as being incurred in "Vintage 4," that is, those subsequent to September 30, 2008. Prior expenditures would continue to be amortized over the originally authorized ten-year period. Additionally, KCP&L would

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[415] Ex. KCP&L 55, pp. 5-6; Ex. KCP&L 605, pp. 4-5.
[416] Ex. KCP&L 55, pp. 5-6; Initial Brief at pp. 192-193.
[417] Ex. KCP&L 239, p. 5, Ex. GMO 240, pp. 13-14, Ex. GMO 241, p. 3. Ex. KCP&L 240, p. 3.
[418] Ex. KCP&L 239, p. 5, Ex. GMO 240, pp. 13-14.
[419] Tr. 3531-32.
[420] Tr. 3501-03.

defer the costs of the DSM programs in Account 182 and, beginning with the December 31, 2010 True Up date in this case, calculate AFUDC monthly using the monthly value of the annual AFUDC rate.[421]

322. Mr. Rush acknowledged that KCP&L and GMO may propose a different method of recovery regardless of whether specific Commission rules are in place or not.[422] He also acknowledged the companies' obligation to comply with MEEIA regardless of whether rules are in place.[423]

323. MDNR's position is that the Commission should direct KCP&L and GMO to follow the intent of the MEEIA goal of achieving all cost-effective demand-side savings, and should further require KCP&L and GMO to expand their DSM programs toward the MEEIA goal of achieving all cost-effective demand-side savings during the "gap" period between the end of these current rate cases and the establishment of the MEEIA rules. The Commission needs to provide guidance with regard to appropriate DSM investment or energy savings targets, continuation and expansion of existing programs.[424]

324. It is unnecessary for the Commission to require KCP&L and GMO to make a filing with the Commission regarding MEEIA legislation as proposed by the Staff.[425]

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[421] Ex. KCP&L 55, pp. 5-6.
[422] Tr. 3547.
[423] Tr. 3546-7.
[424] Ex. KCP&L 210, p. 127; Ex KCP&L 602, p. 3.
[425] Ex. KCP&L 56, p. 3.

Conclusions of Law – Demand-Side Management

34. Utilities within the Commission's jurisdiction must comply with The Missouri Energy Efficiency Investment Act ("MEEIA")[426] regardless of whether or not proposed rules under the law are effective. The language of MEEIA allows KCP&L and GMO to propose a different method of recovery regardless of whether specific Commission rules are in place or not.

35. MEEIA states, "The Commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings."[427] However, the timing of the conclusion of these rate cases and the anticipated implementation of the rules resulting from MEEIA creates a period of time in which KCP&L and GMO will not have guidance from the Commission with regard to appropriate DSM investment or energy savings targets.

36. Amortizing DSM expenses referred to as "Vintage 4," for six years rather than for ten years is inconsistent with the KCP&L regulatory plan. To the extent that costs included in Vintage 4 were incurred as early as September 30, 2008, the regulatory plan would apply to the recovery of Vintage 4 costs.

37. The Commission ordered in prior cases that the carrying costs for the excess margins on OSS would be established at LIBOR plus 32 basis points and that this interest would be included in the unamortized balance of excess OSS margins for amortization over ten years. The Commission also prohibited rate base recognition for the unamortized balance of net reparations from the litigation of Montrose coal freight

[426] Section 393.1075, RSMo.
[427] Section 393.1075.4, RSMo.

rates before the STB and did not otherwise order carrying costs. Staff's netting of DSM costs with unrelated items is inconsistent with the Commission's previous orders.[428]

<u>Decision – Demand-Side Management</u>

The parties did a poor job of defining the issues for this case, but especially with regard to the DSM issues. The Commission, however, has redefined those issues. The over-arching DSM issue is whether the Commission should order the continuance of a DSM program at all. Because of the gap between the MEEIA rules being implemented and the end of the Regulatory Plan, there is a need for the Commission to set out guidance for KCP&L and GMO with regard to the continuance or implementation of DSM programs and cost recovery for those programs. Despite the success and forward momentum created by the implementation of their existing DSM programs and the fact that the programs are currently continuing, both KCP&L and GMO have expressed a position to slow spending for the programs. This decision comes even though both companies realize that they, as well as the ratepayers, stand to benefit from continuing efforts to achieve more DSM programs and improved DSM penetration.

The Companies have argued that the Commission should reject Staff's and MDNR's recommendations to direct the Companies to invest in DSM programs without any assurance that the full costs and lost revenues associated with these programs will be recognized in rates. Instead, the Companies urge the Commission to implement the cost recovery issue expeditiously, including the recovery of lost revenues associated

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[428] *Non-Unanimous Stipulation and Agreement*, p. 8, File No. ER-2010-0089; *In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Implement Its Regulatory Plan*, File No. ER-2007-0291, *Report and Order* (issued December 6, 2007), p. 39.

with the specific DSM programs. While the Companies express a need to have an appropriate cost recovery mechanism, they did not recommend a new recovery mechanism in this case except to propose in their briefs that the mechanism be consistent with that recently ordered for Ameren.

The Commission concludes that the continuance of the DSM programs is in the public interest as shown by the customer participation and clear policies of this state to encourage DSM programs. In the absence of a clear proposal for a cost recovery mechanism and during the gap between the end of the true-up for this case and the implementation of a program under MEEIA, the Commission concludes that the Companies should continue to fund and promote or implement, the DSM programs in the 2005 Agreement (KCP&L only), and in its last adopted preferred resource plan (both KCP&L and GMO). In addition, the Commission directs that those costs be placed in a regulatory asset account and be given the treatment as further described below.

Having determined that the programs should continue, the remaining issues are related to the regulatory treatment to be given to cost recovery and the three different types of regulatory assets. First are the “old” investments -- those DSM investments incurred prior to the last rate case true-up period ending September 30, 2008 (Vintages 1-3). Second, are the “current” investments referred to as “Vintage 4” -- those DSM investments since September 30, 2008, and through the end of the true-up period for this case, December 31, 2010. Third, are the “future” investments -- those DSM investments from December 31, 2010, through the next rate case or until a program is implemented under the MEEIA rules.[429]

[429] Or some other unknown legislative or Commission intervention.

The issues common to these regulatory assets are the length of the amortization period to be given them and how that amortization should be calculated. In other words, should those assets be amortized over a six- or a ten-year period, and should Staff's netting calculation be used to determine the amounts to be amortized. The final issue is should the unamortized balances be added to rate base.

It appears after all the arguments, that there are actually some areas of agreement among and between some of the primary parties. One area of agreement is that the "old" regulatory assets (Vintages 1, 2, and 3) should be governed by the previous decisions to amortize those regulatory asset accounts over a ten-year period and that amortization period should not change. The Commission also agrees and directs that Vintages 1, 2, and 3 continue to be amortized over a ten-year period.

A second area of agreement is that the CPAG should be continued after the end of the regulatory plan and the GMOAG continue for GMO. The Commission also agrees and directs that the advisory groups (or similar groups) shall continue through the "bridge" period until replaced by the implementation of the MEEIA rules or other Commission order.

A third agreement is between KCP&L and GMO and MDNR. Those parties agree that Staff's netting calculation is confusing because it mixes assets unrelated to DSM with DSM assets. In addition, as KCP&L and GMO point out, it causes the calculations to be incorrect because those OSS and STB amounts require different carrying costs calculations as previously ordered by the Commission. Thus, the Commission determines that the DSM account should stand alone and not be netted against unrelated accounts. In addition, the carrying costs should be calculated at the AFUDC rate as set out in the regulatory plan.

The main disagreements among the parties lie with the amortization period for the “current” and “future” investments and whether the unamortized balances should be included in rate base. MDNR supports a temporary adjustment from ten years to six years for the “future” investments amortization period with a carrying cost equal to the AFUDC rate applied to the unamortized balance until KCP&L and GMO have DSM plans and recovery methods in place under MEEIA rules. This would reduce the disincentive for the companies to have these programs and allow the companies to recover their DSM program costs in a timeframe closer to when they occurred. This also makes the treatment of these future costs similar to those of Ameren Missouri in ER-2010-0036.

KCP&L agrees with MDNR regarding the treatment for “future” investments. The Commission agrees as well and will direct that DSM program costs for investments made from December 31, 2010, until a future recovery mechanism is in place shall be placed in a regulatory asset account and amortized over six years with a carrying cost equal to the AFUDC rate applied to the unamortized balance.

With regard to the “current” investments, it would be inconsistent with previous Commission orders to authorize a six-year amortization for the current investments (Vintage 4). The Commission determines that these Vintage 4 investments should continue to be amortized over a ten-year period.

Finally, the Commission must decide whether to include the unamortized balances in rate base. The Commission has determined that it is important to reduce the disincentives to the Companies to having robust DSM programs. The Companies have clearly indicated that delayed recovery is one of those disincentives. By adding the unamortized balances to rate base the Commission will encourage DSM programs and promote the policy of this state as stated in MEEIA. Thus, the Commission determines that the unamortized balances of the regulatory asset accounts shall be included in rate base for determining rates in this case.

<u>E. Fuel Switching Program</u>

Should the Commission adopt MGE's fuel switching proposal?

<u>Findings of Fact – Fuel Switching Program</u>

325. Missouri Gas Energy, a division of Southern Union Company, has proposed to compel KCP&L and GMO, competitors of MGE, to provide incentives to the Companies' customers to decrease their electric usage and convert that consumption to its product—natural gas. MGE's proposal is based on its allegation that natural gas would be more energy efficient.[430]

326. Under the proposed program, KCP&L, GMO, and MGE would offer financial incentives with the aim of converting inefficient electric appliances with fuel-efficient natural gas replacements. KCP&L and GMO would offer financial incentives in the form of rebates or bill credits to residential and multi-family customers to encourage fuel switching from electric water heaters and electric resistance space heating to

[430] Ex. KCP&L 220, Reed Direct Testimony at p. 2.

natural gas.[431] The fuel switching program would be available to current MGE customers as well as customers in MGE's service area who currently do not have natural gas service.[432] In turn, MGE would continue to offer financial incentives to customers for the purchase of energy efficient natural gas appliances through its existing energy efficiency programs. The KCP&L and GMO rebates would serve to defray some of the cost of installing interior piping and ventilation ductwork and other installation costs of new appliances.[433]

327. MGE estimates that 800 customers may participate for GMO[434] and 400 customers may participate from the KCP&L service territory.[435] GMO's total annual program spending for this fuel switching program is estimated at $596,000 and MGE's spending is estimated at $51,200 for energy efficiency appliance incentives plus the cost to install 800 service lines (approximately $1,416,000).[436] KCP&L's program spending for this fuel switching program is estimated at $298,000 and MGE's spending is estimated at $25,600 for energy efficient appliance incentives plus the cost to install 400 service lines (approximately $708,000).[437]

328. MGE gives examples of economic savings for customers switching from electric to natural gas. According to MGE's evidence, a consumer switching from

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431 Ex. GMO 2201, pp. 21-22 and Ex. KCP&L 2201, p. 22. As noted in MGE's testimony, if a customer does not have gas service and does not have a natural gas line to their home, MGE's currently effective tariff provisions regarding facilities extensions would be used. Under this tariff, customer contributions may be required if the extension exceeds 60 linear feet. *See* Ex. KCP&L 2201 and Ex. GMO 2201, pp. 22-23.

432 Ex. KCP&L 2201 and Ex. GMO 2201, pp. 22-23.

433 *See* Ex. KCP&L 2201, pp. 23-24 and Ex. GMO 2201, p. 23.

434 *See* Ex. GMO 2201, p. 27.

435 *See* Ex. KCP&L 2201, p. 27.

436 *See* Ex. GMO 2201, pp. 27-28.

437 *See* Ex. KCP&L 2201, pp. 27-28.

electricity to natural gas would save approximately $606 (GMO) and $536 (KCP&L) for space heating and up to $200 (GMO)[438] and $172 (KCP&L)[439] per year for water heating.

329. MGE's proposal is built on the full fuel cycle or source energy model.[440]

330. Traditionally, appliance efficiency measurements have been "site based," in that they only consider the energy efficiency at the site where the energy is consumed.[441] In contrast, the full fuel cycle approach measures energy consumption over the entire cycle of energy use from extraction or production to transmission, distribution, and finally at the site where the energy is used, such as an appliance.[442] The full-fuel cycle approach considers all of the energy consumed to power the end use application including greenhouse gas emissions.[443]

331. MGE bases its proposal in part on a report from the National Research Council ("NRC") in response to a request from the Department of Energy ("DOE"), Office of Energy Efficiency and Renewable Energy ("EERE") to review the DOE's appliance standard program.[444]

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[438] Ex. GMO 2201, p. 12.

[439] Ex. KCP&L 2203, p. 23. As noted in Mr. Reed's surrebuttal testimony, there was a calculation error in his direct testimony that was corrected in his surrebuttal testimony. Replacement schedules were also filed in his surrebuttal testimony.

[440] Ex. KCP&L 220, pp. 4-11; Tr. 3101-02.

[441] Ex. KCP&L/GMO 2201, p. 5, quoting "A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances," American Gas Association Energy Analysis, EA 2009-3, Oct. 20, 2009.

[442] *See* Ex. KCP&L/GMO. 2201, pp. 5-6; Tr. 3104.

[443] *Id.* at p. 6.

[444] Ex. KCP&L 2201, p. 5; Tr. 3101-02.

332. The DOE is considering whether to adopt the Full-Fuel Cycle approach as an alternative method for measuring energy consumption.[445] The context of the DOE's inquiry is whether to use the Full-Fuel Cycle approach[446] in measuring energy consumption for inclusion on the yellow Energy Guide labels found on home appliances, or whether to continue using the site-based approach.[447] A pending recommendation to the DOE is that the full fuel cycle approach be adopted nationally to provide more comprehensive information to consumers through labels and other means.[448]

333. In appointing a committee to conduct the review of appliance standards, the NRC stated the "committee will not address whether energy conservation standards are appropriate government policy or what levels may or may not be appropriate."[449] Rather, the committee's task was "to evaluate or critique the methodology used for setting energy conservation standards" on appliance and commercial equipment.[450] Further, the committee was not unanimous in its recommendation.[451]

334. All traditional, customer-centric measurement of appliance efficiency show electric appliances are consistently more efficient than a similar gas alternative.[452] The Full-Fuel-Cycle model, however, loads the cost of operation for electrical appliances

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[445] Ex. KCP&L 2201, p. 5.

[446] The full fuel cycle approach is a method of measuring energy consumption not just at the point of use in the home but also the upstream consumption, including production, generation and transmission and delivery of the appliance. Reed Direct at 5-6; Tr. 3104.

[447] Ex. KCP&L 2209.

[448] *See* Ex. KCP&L 2201 and Ex. GMO 2201 pp. 6-7, citing "Review of Site (Point of Use) and Full-Fuel Cycle Measurement Approaches to DOE/EERE Building Appliance Energy Efficiency Standards," National Research Council, May 15, 2009, p. 10.

[449] Ex. KCP&L 2209, p. 16.

[450] Ex. KCP&L 2209, p. 16.

[451] Ex. KCP&L 2209,.

[452] Ex. KCP&L 220, p. 10, Table 1.

with the cost of upstream losses. Only then do the gas appliances surpass electric appliances.

335. Committee Member Ellen Berman indicated that switching from a site-based approach to appliance standards to the Full-Fuel Cycle approach is complex and will not benefit consumers, in part because consumers have no control over the upstream costs included in the Full-Fuel Cycle methodology. [453]

336. A primary tenet of the Full-Fuel Cycle is environmental impact.

337. MGE's testimony is silent with respect to the release of methane, a potent greenhouse gas, caused by the extraction of natural gas.[454] In addition, hydraulic fracturing of shale formations, the primary method currently used to procure new sources of natural gas, has been linked to environmental and health concerns, but has not been thoroughly examined in the course of this proceeding.[455]

338. Fuel switching programs have been adopted by other state's public utility commissions for both combination electric and natural gas utilities as well as stand-alone electric companies across the country.[456]

339. MGE uses several companies with fuel switching programs as examples to support its position. These "comparable" companies, however, differ from both KCP&L and GMO. For instance, where KCP&L and GMO are electric service providers only, the "comparable" companies include diversified companies (electricity, natural gas, pipelines and energy marketing), or combined companies (provider of both electric and

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[453] Ex. KCP&L 2209, Review of Site & Full-Cycle Measurement at 39-40.
[454] Tr. 3130.
[455] Ex. KCP&L 26, pp. 10-12; Tr. 3152.
[456] Fuel switching programs have been approved in Washington, Oregon, Texas, Idaho, and Pennsylvania, among other states. *See* Ex. KCP&L/GMO 2201, p. 20; Ex. KCP&L/GMO 2206.

natural gas services).[457] Additionally, both KCP&L and GMO are strong summer peaking utilities, while at least two of MGE's "comparable" companies are winter peaking utilities.[458]

340. Evidence was presented regarding the carbon dioxide emissions of natural gas residences verses an all-electric home and those emissions for natural gas appliances.[459] However, there was not sufficient evidence for the Commission to make a determination about the environmental effects of natural gas verses electric appliances for KCP&L and GMO customers.

341. MGE cites to Energy Star Performance Rating Methodology for Incorporating Source Energy Use (December 2007).[460] This report, among other things, calculates the source-site ratio for various types of energy. Table 1 on page 3 of the report shows that fuel oil (diesel, kerosene), propane and even wood have similar values to natural gas.

342. The Energy Star Performance Methodology for Incorporating Source Energy Use also discusses the "potential for inefficiency in the conversion of primary fuels" and the "potential for loss when either primary or secondary fuels are transmitted/distributed to individual sites."[461]

343. MGE included its own tables which show comparisons of electric and natural gas consumption under the Full-Fuel Cycle, whereby natural gas appears to be

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457 Ex. KCP&L 239, pp. 10-11; Ex. GMO 240, pp. 19-21.
458 Ex. KCP&L 239, pp. 10-11; Ex. GMO 240, pp. 19-21.
459 *See* KCP&L Ex. 2201 and Ex. GMO 2201 at p. 12, *citing* "A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances," American Gas Association, Energy Analysis, EA 2009-3, October 20, 2009, p. 4, citing to p. 11 the AGA report cited in FN 22. CO2 emissions were 6.4 metric tons for natural gas appliances and 10.1 metric tons for electric appliances.
460 Ex. KCP&L 2201, p. 8, fn. 6.
461 Ex. KCP&L 2201, p. 2.

the more attractive fuel choice.[462] The data used by MGE, however, is not specific to KCP&L, and MGE has not demonstrated that the general data it received from the American Gas Association ("AGA") is applicable to KCP&L.[463] The footnotes which accompany MGE's tables state that the data is from a document entitled "A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances" prepared by the AGA.[464] This document indicates that the AGA's information was developed, in turn, by the Gas Technology Institute for Codes & Standards Research Consortium in a paper entitled "Source Energy and Emission Factors for Building Energy Consumption" (August 2009).[465] The original source of the information relied upon by MGE includes the following statement:

> Average energy and emissions calculations may be appropriate for inventory purposes, but they do not necessarily provide good information when evaluating competing energy efficiency measures.[466]

344. In Table 3 MGE demonstrates the estimated annual cost savings when using water heating and space heating gas and electric appliances.[467] MGE's calculations, however, contain errors. Specifically, the prices used by MGE are not measured in the same units as the consumption. "[T]he consumption is measured in MMBtu, but the price is stated in terms of Dollars per hundred kWh."[468] Correcting for errors shows customers who switch from electricity to natural gas for their water heating

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[462] Ex. KCP&L 2201, pp. 10-11.
[463] *See* Ex. KCP&L 26, p. 20.
[464] *See* Ex. KCP&L 26, p. 20.
[465] *See* Ex. KCP&L 26, p. 20.
[466] *See* Ex. KCP&L 26, p. 20-21.
[467] Ex. KCP&L 2201, p. 13.
[468] Ex. KCP&L 26, p. 22.

needs alone will experience no savings. Rather, their annual bill will increase by over $200 per year.[469]

345. MGE did not provide the results of any Total Resource Cost ("TRC") test for its proposed water heating and space heating fuel substitution program. The Commission has routinely employed the TRC test in its economic analysis of potential energy efficiency measures.[470]

346. For MGE's proposal to be considered a viable energy efficiency measure, the results of the benefit-cost tests would have to be evaluated. KCP&L's witness Goble estimated the required data in order to provide a rough analysis. Mr. Goble's analysis showed that "[t]he costs exceed the benefits in absolute as well as on a present worth basis. . . . [T]he Benefit-Cost ratio is . . . 0.5." [471] Mr. Goble acknowledged that not all water heater fuel substitution programs are unacceptable. However, even with limited data available for his analysis, Mr. Goble concluded "that it would be imprudent to implement the hastily designed electric to gas water heater substitution program recommended by MGE's witness . . . on the basis of economics."[472]

347. Mr. Goble also conducted a Ratepayer Impact Measure ("RIM") test and a Total Participant test. The results of the RIM test indicated that the costs exceed the benefits in every year as well as on a present worth basis, suggesting that implementation of MGE's proposed water heater fuel substitution program will result in

[469] Ex. KCP&L 26, p. 24.
[470] Ex. KCP&L 2201, p. 39.
[471] Ex. KCP&L 26, p. 26.
[472] Ex. KCP&L 26, p. 26.

higher rates for KCP&L's customers.[473] Similarly, customers' costs would exceed the benefits in every year as well as on a present worth basis under the Total Participant test. "Even using very favorable assumptions, the Benefit-Cost ratio is only 0.6."[474]

348. KCP&L also performed an analysis of MGE's proposed space heating electric to natural gas fuel substitution program. In general, the results of the TRC test for space heating were comparable to the results for water heating.[475] The results of the RIM and Total Participant tests revealed costs slightly in excess of the benefits.[476]

349. Like other DSM programs, a fuel switching program has the potential to assist with reducing or deferring KCP&L's and GMO's capital investments in transmission and generation capacity.[477] MGE, however, has neither evaluated its proposed fuel switching program through a Chapter 22 integrated resource analysis, nor performed any analysis of the cost effectiveness of the proposed fuel switching program for KCP&L or GMO.

Conclusions of Law – Fuel Switching Program

38. Demand-side programs are required to undergo scrutiny and review within a 4 CSR 240-22 (Chapter 22) Electric Utility Resource Planning integration analysis. Evaluation of demand-side resources in Missouri must be in compliance with the Commission's Chapter 22 Electric Utility Resource Planning rules. Such rules evaluate all supply-side and demand-side resources on an equivalent basis through

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[473] Ex. KCP&L 26, p. 26-27.
[474] Ex. KCP&L 26, p. 27.
[475] Ex. KCP&L 26, p. 27.
[476] Ex. KCP&L 26, p. 27.
[477] *Id.* at p. 30-31, which describes this and other benefits of the proposed program to KCP&L/GMO.

comprehensive resource analysis, integration analysis, risk analysis and strategy selection. The electric utility uses the Total Resource Cost (TRC) test only in the screening of DSM measures and DSM programs. The electric utility then forwards on the demand-side programs that pass the TRC screening test for consideration as demand-side resources in the utility's Chapter 22 integrated resource analysis.

<u>Decision – Fuel Switching Program</u>

MGE asserts that the Commission should accept the DOE recommendation of the Full-Fuel Cycle to shape the policy of this Commission.[478] KCP&L and GMO contend that the Full-Fuel Cycle model is misleading to the customer and does not reflect any policy guidance. Staff is opposed to the fuel-switching proposal because MGE fails to address two important points: (1) requiring the involuntary adoption of a demand-side program by KCP&L and GMO as proposed by a competitor; and (2) KCP&L and GMO's adoption of demand-side programs that have not been analyzed and reviewed through the Chapter 22 Integrated Resource Planning integration analysis. The Commission is in agreement with Staff.

MGE points to several companies with such fuel switching programs to support its position. These companies, however, differ drastically from both KCP&L and GMO. The Commission finds those differences irreconcilable in that KCP&L and GMO provided electric service only, while MGE's comparables include diversified companies (electricity, natural gas, pipelines and energy marketing) or combined companies

[478] Ex. KCP&L 220, p. 5; Tr. 3101-02; MGE's Initial Brief at 3.

(provider of both electric and natural gas services).[479] Additionally, both KCP&L and GMO are strong summer peaking utilities, while at least two of MGE's comparable companies are winter peaking utilities.[480]

These differences are significant. The fuel switching programs for these comparable companies would result in money moving from "one pocket to the other" within the utility. But, MGE's proposed fuel switching program results in money moving from KCP&L's and GMO's pockets to the pocket of MGE, its competitor. MGE has pointed to no market failure or other evidence that persuades the Commission to take such action.

Furthermore, the Commission determines that there is a need for company demand-side programs to undergo scrutiny and review within a Chapter 22 Electric Utility Resource Planning integration analysis. Such rules evaluate all supply-side and demand-side resources on an equivalent basis through comprehensive resource analysis, integration analysis, risk analysis, and strategy selection. MGE has neither evaluated its proposed fuel switching program through a Chapter 22 integrated resource analysis, nor performed any analysis of the cost effectiveness of the proposed fuel switching program specifically related to KCP&L or GMO.

In addition, MGE's data with regard to which appliances are most energy efficient relied on studies and reports that have not been shown to be directly related to KCP&L and GMO's customers, contain calculation errors, or are not reliable for the purposes intended by MGE. The Commission was persuaded by Mr. Goble's analysis for the

[479] Ex. KCP&L 239, pp. 10-11; Ex. GMO 240, pp. 19-21.
[480] Ex. KCP&L 239, pp. 10-11; Ex. GMO 240, pp. 19-21.

efficiency, or lack thereof for the proposal. Thus, the Commission gives little weight to the reports and recommendations relied on by MGE in this proceeding.

Finally, as KCP&L points out, the DOE recommendation is not yet final and the environmental issues associated with this fuel switching proposal have not been completely examined in this proceeding. MGE is silent on at least two major environmental concerns with natural gas – the release of methane and hydraulic fracturing. The Commission does not have sufficient evidence in this record regarding the environmental effects to determine in this case that natural gas is less harmful to the environment.

There may be some advantages to fuel switching in the appropriate situations and the Commission, by this order, is not indicating that it will not consider such proposals in the future. The Commission, however, does not find this proposal by KCP&L's and GMO's competitor within those utilities' rate cases to be one of those situations. The Commission concludes it is not in the best interests of Missouri ratepayers to adopt the fuel switching program based on the findings and conclusions above. Therefore, the Commission will not require the fuel switching program as proposed by MGE.

II. Rate of Return

Having determined what should be included in rate base, the Commission will now decide what rate of return should be included in rates to compensate GPE's shareholders and creditors.

A. Return on Equity

What return on common equity should be used for determining KCP&L's rate of return?

Findings of Fact – Return on Equity

350. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and stock price appreciation. Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow ("DCF") method assumes the current market price of a firm's stock is equal to the discounted value of all expected future cash flows.[481]

351. The Risk Premium method assumes that all of the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds.[482]

352. The Capital Asset Pricing Method ("CAPM") assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.[483]

353. Three financial analysts offered recommendations regarding an appropriate return on equity in this case.

[481] Ex. KCP&L 1203, pp. 13-14.
[482] Ex. KCP&L 27, p. 14.
[483] Ex. KCP&L 1203, p. 32.

KCP&L Witness Hadaway

354. Dr. Hadaway recommends an ROE of 10.75%. His range of ROE recommendations is from 10.2% to 10.8%, with a midpoint of 10.5%. However, he also adds 25 basis points to his ROE recommendation based on what he considers to be KCP&L's excellent customer service, to arrive at 10.75%.[484]

355. He began by constructing a proxy group of 31 companies.[485] Those companies were at least BBB (investment grade), get at least 70% of revenues from regulated utility sales, have consistent financial records unaffected by recent mergers or restructuring, and a consistent dividend record with no cuts the past two years.[486]

356. Dr. Hadaway testified that the techniques for estimating ROE fall into three categories: comparable earnings methods, risk premium methods, and Discounted Cash Flow ("DCF") methods.[487] The DCF is the most widely used regulatory ROE method.[488]

357. The DCF concept is based on the theory that stock prices represent the present value or discounted value of all future dividends investors expect.[489] The DCF is simply the sum of the expected dividend yield and the expected long-term dividend (or price) growth rate.[490]

358. Dr. Hadaway applied three DCF versions to his proxy group. First, he applied a constant growth method. Second, he used a non-constant method, using

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[484] Ex. KCP&L 28, pp. 2, 22.
[485] Ex. KCP&L 27, p. 6.
[486] *Id.* at 4.
[487] *Id.* at 13.
[488] *Id.* at 15.
[489] *Id.* at 16.
[490] *Id.* at 15.

estimated long-term GDP for estimated growth. Third, he employed a two-stage growth method, with stage one based on ValueLine's 3-5 year dividend projections, and stage two based on long-term projected growth in GDP.[491]

359. Dr. Hadaway's DCF results with the traditional constant growth model were a range of 10.5-10.7%. With the GDP growth rate, his constant growth model showed an ROE of 11%. His Multistage DCF yielded a 10.8% result. The overall results of his DCF show a range of 10.5-11%.[492] These results are in line with Dr. Hadaway's risk premium ROE range of 10.61-10.82%.[493]

MEUA, MIEC and DOE Witness Gorman

360. Mr. Gorman suggests that 9.65% is the appropriate ROE.[494] He bases his recommendation on using a constant grown DCF, a sustainable growth DCF, a multi-stage growth DCF, risk premium, and Capital Asset Pricing Model ("CAPM").[495]

361. Mr. Gorman applied those five ROE methods to the same proxy group Dr. Hadaway used.[496] Mr. Gorman posits that because the proxy group's senior secured credit rating from Moody's is "A3", which is identical to KCP&L's senior secured credit rating, the proxy group has a comparable total investment risk to KCP&L.[497]

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[491] *Id.* at 39.
[492] *Id.* at 42.
[493] *Id.* at 43.
[494] Ex. KCP&L 1203, p. 37.
[495] *Id.* at 2.
[496] *Id.* at 11.
[497] *Id.*

362. Mr. Gorman stated that the average and median growth rates for constant growth DCF are 5.68 and 5.41%, respectively.[498] Further, the average and median constant growth DCF ROE's are 10.48 and 10.39%, respectively.

363. His sustainable growth DCF, which is based on the percentage of earnings retained and reinvested, showed average and median growth rates of 4.92% and 4.59%, respectively. The average and median ROE for sustainable growth DCF was 9.74% and 9.38%, respectively.[499]

364. Mr. Gorman's multistage growth DCF, which reflect a chance of non-constant growth, showed an estimate of 4.75% long-term growth. His ROE analysis revealed a 9.78% average and 9.86% median.[500]

365. Mr. Gorman's also arrived at an ROE range using a risk premium analysis. His results showed an ROE range of 9.41% to 9.94%, with a midpoint of 9.68%.[501] Finally, his CAPM method to estimate ROE showed a range of 8.33 to 9.38%. His overall range of ROEs using these five methods was 9.4% to 9.9%, with a midpoint of 9.65%.[502]

<u>Staff Witness Murray</u>

366. Mr. Murray arrived at an ROE range of 8.5-9.5%, with 9.0% being the midpoint.[503] As did Dr. Hadaway and Mr. Gorman, Mr. Murray constructed a proxy

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498 *Id.* at 20.
499 *Id.* at 24.
500 *Id.* at 26.
501 *Id.* at 32.
502 *Id.* at 37.
503 Ex. KCP&L 210, p. 11.

group. The criteria for his proxy group were: 1) an electric utility by Value Line; 2) publicly traded stock; 3) classified as regulated utility by EEI or not followed by EEI; 4) at least 70% of revenues from electric operations or not followed by AUS; 5) ten years of Value Line historical growth data available; 6) no reduced dividend since 2007; 7) projected growth available from Value Line and Reuters; 8) at least investment grade credit rating; 9) company-owned generating assets; 10) significant merger or acquisition accounted in last three years.[504]

367. Mr. Murray also used a constant growth DCF. His dividend yield was produced by dividing a weighted average of the 2010 (25%) and 2011 (75%) Value Line projected dividends per share by the monthly high/low average stock price for the three months ending September 30, 2010.[505]

368. Mr. Murray stated that the cost of equity is sum of dividend yield and growth rate. To estimate growth rate, he considered actual dividends per share, earnings per share and book value per share. The historical growth rates are volatile. Due to volatility and wide dispersions of historical and projected DPS, EPS and BVPS, Staff instead use an alternative input. Using a growth rate of 4-5%, and a projected dividend yield of 4.7%, Mr. Murray arrived at a constant growth DCF of 8.7-9.7%. But, the constant growth DCF is not instructive if the industry or economic circumstances cause expected near-term growth to be inconsistent with sustainable perpetual growth. This is the case here. So, Staff instead is using a multistage DCF.[506]

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[504] *Id.* at 26.
[505] *Id.* at 27.
[506] *Id.* at 28-29.

369. A three-stage DCF is used in Staff's analysis. The stages are years 1-5, 6-10, and 11 to infinity. For stage one, Staff gave full weight to analysts' five-year EPS growth estimates. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level. The estimated ROE for the proxy group is about 8.7 to 9.4%, with a midpoint of 9.05%.[507]

370. Mr. Murray also tested the reasonableness of his DCF results by using CAPM and other evidence. For the risk-free rate in its CAPM, he used the average yield on 30-year Treasury bonds for the three months ending September 30, 2010, which was 3.85%. The average beta for the proxy group is 0.65. For market risk premium, Staff relied on risk premium estimates based on historical differences between earned returns on stocks and on bonds. The first risk premium was based on long-term arithmetic average of differences from 1926 to 2009, which was 6%. The second was based on geometric average, which was 4.4%. The CAPM results are 7.72% for arithmetic and 6.69% for geometric. Also, Staff's estimation of ROE by adding risk premium to yield to maturity of the company's long-term debt gives an ROE of 8.14-8.71.[508]

371. Staff submitted testimony concerning recent average ROEs. According to RRA, average ROEs for electrics for first three quarters of 2010 was 10.36%. For the first quarter, 10.66%, 17 decisions. Second quarter 10.08%, 14 decisions. Third quarter, 10.27%, 12 decisions. For 2009, average was 10.48%. First quarter, 10.29%, 9 decisions. Second quarter, 10.55%, 10 decisions. Third quarter, 10.46%,

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[507] *Id.* at 30.
[508] *Id.* at 35-36.

3 decisions. Fourth quarter, 10.54%, 17 decisions. Staff's ROR (not ROE) is in line w/ the average RORs for first three quarters of 2010.[509]

Analysis – Return on Equity

372. Dr. Hadaway relies exclusively on three variations of the DCF analysis.[510]

373. First, Dr. Hadaway conducted a constant growth DCF analysis relying on analysts' growth estimates which resulted in a return on equity of 10.2% to 10.4%.[511]

374. Second, Dr. Hadaway conducted a constant growth DCF analysis that substituted his own subjective estimation of the long-term GDP growth rate. The result of this analysis is a return on equity of 10.7% to 10.8%.[512]

375. Finally, Dr. Hadaway combines the analysts' growth estimates and his own estimation of long-term GDP growth into a multi-stage DCF analysis. The result of his multi-stage DCF analysis is a return on equity of 10.5%.[513]

376. Thus, Dr. Hadaway recommends a return on equity range of 10.2% - 10.8%, with a midpoint of 10.5%.[514]

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509 Ex. KCP&L 210, p. 37.

510 While Dr. Hadaway initially included the results of his risk premium analysis in his direct testimony (Ex. KCP&L 27, p. 43), he subsequently recommended that the results of his updated risk premium analysis in his rebuttal testimony should be discounted (Ex. KCP&L 28, p. 23). The results of that updated risk premium analysis indicate an ROE range of 10.05% - 10.24%. (*Id.*)

511 Ex. KCP&L 28, Sch. SCH2010-11

512 *Id.*

513 *Id.*

514 *Id.* at p. 22.

377. In its testimony, however, KCP&L asks that the Commission set its return on equity at 10.75%, at the top end of Dr. Hadaway's recommended range.[515]

378. KCP&L does so "to reflect the Company's reliability and customer satisfaction achievements."[516]

379. Michael Gorman testified on behalf of MEUA, MIEC and the Department of Energy.[517]

380. Mr. Gorman conducts three versions of the DCF analysis, a risk premium analysis and a CAPM analysis. First, Mr. Gorman conducts a constant growth DCF analysis based upon analysts' growth rates resulting in a return on equity of 10.39%.[518]

381. Second, Mr. Gorman conducts a sustainable growth DCF analysis which resulted in a return on equity of 9.38%.[519]

382. Third, Mr. Gorman conducts a multi-stage DCF analysis which results in a return on equity of 9.86%.[520]

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515 In KCP&L/GMO's testimony, they refer to their request as a "return on equity commensurate with the top of Dr. Hadaway's range." (Ex. KCP&L 7, p. 10). In their brief, however, KCP&L/GMO refers to their request as "an additional 25 basis points be added to the midpoint." (KCP&L/GMO Brief at p. 151). While the methods of getting to the actual request are different, the practical effect of either methods is a requested return on equity of 10.75%

516 Ex. KCP&L 7, p. 10.

517 Mr. Gorman initially presented the results of his return on equity analysis in the context of his KCP&L Direct Testimony (Ex. KCP&L 1203). His recommendation in his Direct Testimony is a midpoint return on equity of 9.65%. Like Dr. Hadaway, Mr. Gorman subsequently updated his analysis in his GMO Direct Testimony resulting in a midpoint return on equity of 9.50%. (Ex. KCP&L 1403). On the stand, however, Mr. Gorman restored his original recommendation of 9.65% to account for the subsequent increase in capital market bond yields. (Tr. 2852-2853). Therefore, the results set forth in this order reflect the "restored" position contained in Mr. Gorman's KCP&L Direct Testimony of 9.40% to 9.90% with a midpoint of 9.65%. (Ex. KCP&L 1203, p. 37).

518 Ex. KCP&L 1203, pp. 20 and 27.

519 *Id.* at pp. 24 and 27.

520 *Id.* at pp. 26 and 27.

383. Thus, the average of Mr. Gorman's three DCF analyses is a return on equity of 9.88%.[521]

384. Next, Mr. Gorman undertook a risk premium analysis with a return on equity range of 9.41% to 9.94% with a midpoint of 9.68%.[522]

385. Finally, Mr. Gorman conducts a CAPM analysis resulting in a return on equity of 9.40%.[523]

386. The ultimate result of Mr. Gorman's multiple analyses is a recommended return on equity of 9.40% to 9.90% with a midpoint of 9.65%.[524]

387. Staff witness Murray listed the expected long-term growth rate in electricity demand, plus inflation, in support of his ROE recommendation of 8.5-9.5%, with a midpoint of 9.0%.

388. He also listed the "Rule of Thumb": a rough estimate of the current cost of equity calculated by adding a 3-4% risk premium to the cost of long-term debt. In this case, the "rule of thumb" suggests a cost of common equity in the range of 8.14%-9.71%.[525]

389. Finally, Murray also used the perpetual growth rate used by Goldman Sachs when performing DCF analyses of regulated electric companies, which is 2.5%.[526]

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[521] *Id.* at p. 27.
[522] *Id.* at p. 32.
[523] *Id.* at p. 37.
[524] *Id.*
[525] Ex. KCP&L 235, p. 5.
[526] *Id.,* p. 9.

Growth Rates

390. As previously mentioned, all three experts rely upon analysts' growth rates for use in their initial constant growth DCF. As the Commission found in its recent AmerenUE decision, these analysts' growth rates are currently troublesome in that they are "based on a unsustainably high dividend yield and median growth rate."[527]

391. While the DCF methodology is intended to be perpetual in nature, these underlying analyst growth estimates are only focused on the short-term. As Mr. Gorman explains, therefore, these current short-term growth rates are based upon the expectation of increased earnings resulting from the large construction cycle currently seen in the electric industry. Such growth rates are not reflective of more normalized levels of construction and are therefore not sustainable.[528]

392. In order to avoid the short-term nature of analysts' growth rates, Dr. Hadaway replaces the analysts' growth rates with an estimate of long-term GDP growth. While the use of a long-term GDP growth rate certainly appears more reasonable than the analysts' growth estimates, the GDP growth estimation provided by Dr. Hadaway is troublesome. As pointed out by Mr. Gorman, Dr. Hadaway rejects all recognized measures of GDP growth and instead provides his own estimate of GDP growth (6.0%)[529] based upon historical average GDP growth rates.[530]

393. If Dr. Hadaway's subjective estimate of GDP growth (6.0%) is replaced with publicly available estimate of GDP growth (Mr. Gorman uses the 4.75% estimate

[527] *Report and Order*, File No. ER-2010-0036, ("*AmerenUE*") p. 21.
[528] Ex. KCP&L 1203, p. 22.
[529] Ex. KCP&L 27, p. 41.
[530] Ex. KCP&L 1204, pp. 7-8.

provided by *Blue Chip Economic Indicators*), the result of Dr. Hadaway's constant growth (GDP) DCF analyses drops from 10.7% to 9.6%.[531]

394. By replacing Dr. Hadaway's subjective GDP growth estimate with a publicly available GDP growth estimate, Dr. Hadaway's DCF analysis leads to results that fall comfortably within the range recommended by Mr. Gorman (9.4% - 9.9%).[532]

<u>Other Return on Equity Methodologies</u>

395. Dr. Hadaway initially conducted a risk premium analysis. As contained in his direct testimony, Dr. Hadaway considered the results of the risk premium analysis when it resulted in a return on equity of 10.61% to 10.82%.[533]

396. Given the significant passage of time (six months between filing direct testimony and rebuttal testimony), Dr. Hadaway updated his analysis in his rebuttal testimony.[534]

397. In that testimony, Dr. Hadaway's risk premium analysis decreased significantly to a range of 10.05% to 10.24%.[535]

398. Based upon his belief that "current utility bond yields are artificially depressed by government monetary policy," Dr. Hadaway decided to "discount these results."[536]

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[531] Ex. KCP&L 1205, p. 10.
[532] Ex. KCP&L 1205, p 12.
[533] Ex. KCP&L 27, p. 43.
[534] Ex. KCP&L 28, p. 22.
[535] *Id.* at 23.
[536] *Id.*

399. The Commission finds Mr. Gorman's testimony to be more credible than the testimony of Mr. Murray and Dr. Hadaway. However, Mr. Gorman's testimony also gives the Commission some concern. For example, Mr. Gorman's Constant Growth DCF model using analysts' growth rates yields 10.39% (KCP&L) and 10.33% (GMO) ROE estimates, whereas Dr. Hadaway's model runs from 10.2% to 10.4%, essentially agreeing with Mr. Gorman. It is therefore ironic that the Industrials criticize Dr. Hadaway's Constant Growth DCF model, when their own expert essentially agrees with the Hadaway analysis.[537]

400. Mr. Gorman took a CAPM range of 8.12% to 9.17%, relied on the high-end of that range, and then rounded it up to 9.20%.[538]

401. When assessing growth rates, Mr. Gorman utilized a *median* growth rate of 5.41% for his Constant Growth DCF analysis, instead of *average* growth rates (5.68% for KPC&L or 5.63% for GMO) which would have boosted his ROE estimate.[539]

402. Similarly, for his long-term Growth DCF analysis, Mr. Gorman chose *median* growth rates for KCP&L and GMO of 4.59% and 4.61%, compared with *average* rates of 4.92% and 4.89%, respectively, that would have increased his ROE calculation.[540]

403. Mr. Gorman also arbitrarily eliminated Empire District Electric Company growth rates from his Constant Growth DCF models which would have increased the median ROE two basis points.[541]

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537 Ex. KCP&L 1203, p. 27; Ex. GMO 1403, p. 29; Ex. KCP&L 27, p. 22 and Sch. SCH2010-11, p. 2.
538 Ex. GMO 1403, p. 39.
539 Ex. KCP&L 1203, p. 20; Ex. GMO 1403, p. 21.
540 Ex. KCP&L 1203, p. 24; Ex. GMO 1403, p. 25.
541 Ex. KCP&L 28, pp. 17-18.

404. Staff witness Murray did not use data that could be confirmed by either government or industry statistics, and chose instead to reject a 5.97% growth rate based on Value Line and Reuters data, finding it "non-sustainable."[542]

405. He then arrived at a 4.0%-5.0% growth rate "based upon Staff's expertise and understanding of current market conditions."[543]

406. Admitting that he cited no authority to reduce the 5.97% growth rate by 100 to 200 basis points,[544] Mr. Murray was vague on whom he consulted and how this process of reducing a growth rate based on public information occurred.

<u>Return on Equity Awards in Other Jurisdictions</u>

407. The Commission must not only look at the experts' evidence, but must also award a return on equity "equal to that generally being made at the same time <u>*and in the same general part of the country*</u> on investments in other business undertakings which are attended by corresponding risks and uncertainties."[545]

408. KCP&L itself asks for the Commission to look at Midwestern ROE's to assist the Commission in setting KCP&L's ROE, stating that "If the Commission is concerned about attracting capital to Missouri's utilities, it will pay attention to ROEs issued by other states in the Midwest."[546]

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[542] Tr., 2992.
[543] Ex. KCP&L 210; Tr. 2992-98.
[544] Tr. 2998.
[545] *Bluefield v. PSC*, 262 U.S. at 692 (emphasis added).
[546] *See* KCP&L Reply Brief at 86.

409. A review of recent return on equity awards reveals that nine vertically integrated utilities in states that border Missouri (except for Northern Indiana Public Service) have received an average return on equity award of approximately 10.25%.[547]

KCP&L Request for Adder Due to Customer Service Excellence

410. Further, KCP&L/GMO ask that the Commission set its return on equity at the upper half of the recommended range of return on equity "to reflect the Company's reliability and customer satisfaction achievements."[548] In its Direct Testimony, KCP&L/GMO allege heightened customer satisfaction and reliability. In support of this claim, KCP&L/GMO reference the Commission to an annual Edison Electric Institute Reliability Survey and recent J.D. Power awards.

411. Evidence provided by Staff, however, provides real world evidence that KCP&L/GMO's performance is the lowest among the Missouri electric utilities. While KCP&L's current rating is 655, this represents a dramatic decrease from the 697 score received in just 2007.[549]

412. KCP&L's customer satisfaction, as measured by Commission complaints is the worst in the state.

> And KCPL from 2008, 2009, 2010, if I calculated this correctly, they are actually 48 percent higher in residential complaints from 2010 to 2008. Empire has declined. Ameren has I would say remained relatively

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547 Ex. KCP&L 102 (Interstate Power & Light – 10.8, Westar Energy – 10.4, Kansas Gas & Electric – 10.4, Union Electric – 10.1, Entergy Arkansas – 10.2, Kentucky Power – 10.5, Northern Indiana Public Service – 9.9, KCP&L – 10.0, Interstate Power & Light – 10.)

548 Ex. KCP&L 7, p. 10.

549 Tr. 2960-2961.

constant. GMO, a little bit of increase. _But KCPL dramatic increase in customer complaints_.[550]

Conclusions of Law – Return on Equity

39. The Commission must estimate the cost of common equity capital. This is a difficult task, as academic commentators have recognized.[551] The United States Supreme Court, in two frequently cited decisions, has established the constitutional parameters that must guide the Commission in its task.[552] In the earlier of these cases, *Bluefield Water Works*, the Court stated that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[553]

In the same case, the Court provided the following guidance as to the return due to equity owners:

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

[550] Tr. 2962.
[551] C.F. Phillips, Jr., *The Regulation of Public Utilities*, 390 (1993); Goodman, 1 *The Process of Ratemaking*, *supra,* at 606.
[552] *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943); *Bluefield Water Works & Improv. Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923).
[553] *Bluefield, supra,* 262 U.S. at 690, 43 S.Ct. at 678, 67 L.Ed. at 1181.

> to raise the money necessary for the proper discharge of its public duties.[554]

The Court restated these principles in *Hope Natural Gas Company*, the later of the two cases:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[555]

40. The Commission must draw primary guidance in the evaluation of the expert testimony from the Supreme Court's *Hope* and *Bluefield* decisions. Pursuant to those decisions, returns for GPE's shareholders must be commensurate with returns in other enterprises with corresponding risks. Just and reasonable rates must include revenue sufficient to cover operating expenses, service debt and pay a dividend commensurate with the risk involved. The language of *Hope* and *Bluefield* unmistakably requires a *comparative method*, based on a quantification of risk.

41. Investor expectations are not the sole determiners of ROE under *Hope* and *Bluefield*; we must also look to the performance of other companies that are similar to KCP&L in terms of risk. *Hope* and *Bluefield* also expressly refer to objective measures. The allowed return must be sufficient to ensure confidence in the financial

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[554] *Id.*, 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.
[555] *Hope Nat. Gas Co., supra,* 320 U.S. at 603, 64 S.Ct. 288, 88 L.Ed. 345 (citations omitted).

integrity of the company in order to maintain its credit and attract necessary capital. By referring to confidence, the Court again emphasized risk.

42. The Commission cannot simply find a rate of return on equity that is "correct"; a "correct" rate does not exist. However, there are some numbers that the Commission can use as guideposts in establishing an appropriate return on equity. The Commission stated that it does not believe that its return on equity finding should "unthinkingly mirror the national average."[556] Nevertheless, the national average is an indicator of the capital market in which MGE will have to compete for necessary capital.

43. The Commission has described a "zone of reasonableness" extending from 100 basis points above to 100 basis points below the recent national average of awarded ROEs to help the Commission evaluate ROE recommendations.[557] Because the evidence shows the recent national average ROE for electric utilities is 10.34%,[558] that "zone of reasonableness" for this case is 9.34% to 11.34%.

44. The Commission has wide latitude in setting an ROE within the zone of reasonableness.[559] The zone of reasonableness is simply a tool to help the Commission to evaluate the recommendations offered by various rate of return experts. It should not be taken as an absolute rule that would preclude consideration of recommendations that fall outside that zone.

45. In the final analysis, the method employed to estimate the cost of common equity is unimportant, as long as the result that is reached satisfies the constitutional

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556 *In re Missouri Gas Energy*, 12 Mo.P.S.C.3d 581, 593 (*Report and Order* issued September 21, 2004).
557 *Id.*
558 Ex. KCP&L 102.
559 *State ex. rel. Public Counsel,* 274 S.W.3d at 574 (*citing In re Permian Basin Area Rate Cases*, 390 U.S. 747, 767, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968))("**courts are without authority** to set aside **any** rate selected by the Commission [that] is within a 'zone of reasonableness') (emphasis supplied).

requirements.[560] "If the total effect of the rate order cannot be said to be unjust or unreasonable, judicial inquiry is at an end."[561] "It is the impact of the rate order which counts; the methodology is not significant."[562] Within a wide range of discretion, the Commission may select the methodology.[563]

46. The Commission may select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances.[564] It may employ a combination of methodologies and vary its approach from case-to-case and from company-to-company.[565] "No methodology being statutorily prescribed, and ratemaking being an inexact science, requiring use of different formulas, the Commission may use different approaches in different cases."[566]

47. The Constitution "does not bind ratemaking bodies to the service of any single formula or combination of formulas."[567] "Agencies to whom this legislative power

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[560] *State ex rel. Arkansas Power & Light Company v. Missouri Public Service Commission***,** 736 S.W.2d 457, 462 (Mo. App., W.D. 1987); *State ex rel. Associated Natural Gas Company v. Public Service Commission of Missouri,* 706 S.W.2d 870, 879 (Mo. App., W.D. 1985).

[561] *Hope*, *supra,* 320 U.S. at 602, 64 S.Ct. at 287, 88 L.Ed. 345 at ___ .

[562] *State ex rel. GTE North, Inc. v. Public Serv. Commission***,** 835 S.W.2d 356, 361, 371 (Mo. App., W.D. 1992).

[563] *Missouri Gas Energy v. Public Service Commission*, 978 S.W.2d 434 (Mo. App., W.D. 1998), *rehearing and/or transfer denied*; *State ex rel. Associated Natural Gas Company v. Public Service Commission*, 706 S.W.2d 870, 880, 882 (Mo. App., W.D. 1985); *State ex rel. Missouri Public Service Company v. Fraas*, 627 S.W.2d 882, 888 (Mo. App., W.D. 1981).

[564] *State ex rel. Associated Natural Gas Company v. Public Service Commission of Missouri,* 706 S.W.2d 870, 880 (Mo. App., W.D. 1985).

[565] *State ex rel. City of Lake Lotawana v. Public Service Commission*, 732 S.W.2d 191, 194 (Mo. App., W.D. 1987).

[566] *Arkansas Power & Light***,** *supra,* 736 S.W.2d at 462.

[567] *Federal Power Commission v. Natural Gas Pipeline Company*, 315 U.S. 575, 586, *62 S.Ct. 736, 743, 86 L.Ed. 1037, 1049-50* (1942).

has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances."[568]

Decision – Return on Equity

After careful review of the evidence and of return on equity awards in nearby states, the Commission finds that KCP&L should receive a return on equity award of 10.0%. This is very near the Midwestern average for 2010, and supported by the evidence.

For example, Mr. Gorman found the average constant growth DCF to be 10.48, and the average sustainable growth to be 9.74.[569] The average of those two numbers is 10.1.

Likewise, he found the median constant growth DCF to be 10.39, and the median sustainable growth DCF to be 9.83.[570] The average of those two numbers is also 10.1.

Further, Hadaway and Gorman, in their critiques of each other's work, point out that if the other witness' work had been done properly, their ROE analysis would yield a result of about 10%.[571]

568 *Id.*
569 Ex. KCP&L 1203, pp. 20, 24.
570 *Id.*
571 Ex. KCP&L 1204, pp. 5, 10; Ex. KCP&L 28, p. 16.

B. Cost of Debt

What capital structure should be used for determining the rate of return?

Findings of Fact – Cost of Debt

413. The issue of KCP&L's cost of debt was decided in the Report and Order issued in ER-2010-0355. Thus, only GMO's cost of debt is addressed here.

414. GMO has proposed a capital structure that reflects its actual cost of debt with the exception of only one debt issuance. The Company's cost of debt was originally projected to be 6.73%, but based upon year-end 2010 actual results, GMO has lowered this figure to 6.42%.[572]

415. GMO's cost of debt is generally based upon GMO's actual debt cost, with the exception of one issue, the 11.875% Senior Notes of $500 million. These Senior Notes continue to use a hypothetical cost of 6.26% which was first assigned by GMO's predecessor Aquila. This hypothetical cost was part of Aquila's commitment to the Commission to hold its customers harmless from the effects of Aquila's unsuccessful non-regulated operations. Since Aquila's acquisition by Great Plains Energy in July 2008, both Great Plains Energy and GMO have continued this commitment which serves to benefit ratepayers.[573]

416. Staff recommends using The Empire Electric District as a proxy for GMO's debt on the Senior Notes 6.36%.[574] Staff cites as support for its position that GMO's

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[572] Ex. GMO 15, p. 6; Ex. GMO 54, pp. 1-2.

[573] *See Report and Order*, *In re Great Plains Energy Inc.*, File No. EM-2007-0374 at 145-46, 156 and n. 609, 248-50 (July 1, 2008) ("Merger Order").

[574] Ex. GMO 269, p. 3.

cost of debt assignment process is "not based on market-driven, arm's-length transactions."[575]

417. The factors that dictate a utility's cost of debt include the maturity of the debt; the timing and amount of the debt; the terms and conditions of the debt; the credit profile of the company when the debt is issued; alternative sources of funding; the utility's market capitalization; and the financial market conditions existing when the debt is issued.[576] Staff did not utilize any of these factors in arriving at its recommendation to use Empire's debt as a proxy for GMO.[577]

418. There are substantial differences between Empire and GMO, including that: Empire serves no major metropolitan while GMO does; Empire has only 170,000 customers compared to GMO's over 300,000 customers; and Empire has a generation capacity significantly lower than GMO's 2,000 MWs. In addition, Empire does business in four states, is subject to four separate regulatory commissions, and operates a natural gas distribution utility, whereas GMO operates only in Missouri as an electric utility.[578]

419. The 11.875% Senior Notes mature in mid-2012. Because of this there is no reason to depart from the current cost of debt assigned to this issue or to GMO. As such, there is no need to adopt as a proxy for GMO's cost of debt the debt cost of a proxy which Staff proposed. Staff's recommendation that the Commission use the cost of debt of The Empire District Electric Company is not reasonable as Empire's debt does not reflect the debt of GMO.

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575 Ex. GMO 235, p. 26.
576 Ex. GMO 9, p. 7.
577 Tr. 4017.
578 Tr. 4015-17.

420. The Commission finds that GMO's cost of debt is 6.42%.

421. The Commission finds that at this time the use of a consolidated debt structure, which was not specifically proposed by Staff, is not necessary.

Conclusions of Law – Cost of Debt

There are no additional Conclusions of Law for this section.

Decision – Cost of Debt

The Commission finds this issue in favor of GMO.

C. Equity Linked Convertible Debt

Should GPE's equity linked convertible debt be included in KCP&L's capital structure? If so, at what interest rate?

Findings of Fact – Equity Linked Convertible Debt

422. The equity-linked convertible debt known as Equity Units should be part of the companies' capital structure and should be included at their cost of 13.59%. GPE raised gross proceeds of $450 million in May 2009 through a simultaneous issuance of 11.5 million shares of common stock ($14/share resulting in gross proceeds of $161 million) and 5.75 million Equity Units ($50/unit resulting in gross proceeds of $287.5 million). It was cheaper for GPE to raise capital through the equity units because a portion of the quarterly distribution is tax deductible.[579]

[579] *See* Tr. 2902.

423. As a result, the Equity Units were a lower cost alternative to issuing common stock and would ultimately cost ratepayers less.[580]

424. The only basis for Staff's argument that the cost of the Equity Units should be 11.14% (or 245 basis points below the actual cost to GPE) is that a much larger utility, FPL Group (the parent of Florida Power & Light Co.) issued its Equity Units at a lower cost. Mr. Murray testified that Staff's adjustment of 245 basis points was not based on any other equity offering that any other company made in 2009.[581]

425. Unlike Mr. Cline and the authors of Schedules MWC 2010-4 through 2010-6 (Goldman Sachs & Co. and J.P. Morgan), Mr. Murray has never been employed by a firm that served as manager of an offering of equity units, nor has he ever worked for a company that issued such equity units. He agreed with the Goldman Sachs analysis that GPE's offering price was the third best pricing of any offering of equity units in 2009. [582]

426. J.P. Morgan also explained that the FPL equity units represented only 1.5% of its equity market capitalization, in comparison with the GPE's offering which was 16.6% of its equity market capitalization.[583]

427. Additionally, Mr. Cline noted that J.P. Morgan stated that FPL's equity units offering was more senior in the capital structure of the company, in comparison with GPE, where its Equity Units were further subordinated to other debt.[584]

[580] *Id.*
[581] *See* Tr. 2975.
[582] *See* Tr. 2980-81; Sch. MWC 2010-6 at 3GPE's offering was priced at a 6.08% spread over its common dividend yield, representing the third best pricing of any transaction in 2009 (behind FPL at 4.98% and Johnson Controls at 5.69%).
[583] *Id.*
[584] *Id.*

428. Finally, FPL had previously issued $506 million of Equity Units in 2002 and had a track record that investors could rely on, whereas GPE had never before issued Equity Units.[585]

429. Mr. Murray did accept Mr. Cline's testimony, consistent with the Goldman Sachs reports (Cline Schedule MWC 2010-4 and 2010-5), which stated that investors in Equity Units "demand higher yield than common stock" and that "security [is] more expensive than equity in [a] downside scenario."[586]

430. Although Staff noted that Schedule MWC 2010-5 was prepared after Staff had filed its initial case, Mr. Cline testified that the report was entirely consistent with the earlier Goldman Sachs report (MWC-2010-4) that was prepared on March 17, 2009.[587]

431. Although Staff suggested that the cost of the Equity Units was greater because of the negative impact of GMO on GPE's credit ratings, Mr. Cline, while rejecting Staff's premise, did not elaborate given his further explanation that GPE's dividend yield, not its credit rating, was the primary factor in the pricing of these Equity Units.[588]

432. Overall, the cost of the Equity Units was reasonable and was incurred in the best interests of the ratepayers.[589]

<u>Conclusions of Law – Equity Linked Convertible Debt</u>

There are no additional Conclusions of Law for this section.

[585] *See* Sch. MWC 2010-5, pp. 1, 4; Sch. MWC 2010-6, p. 1.
[586] Tr. 2977.
[587] Tr. 2900-01.
[588] Tr. 2903; Ex. KCP&L 12, pp. 8-10.
[589] Tr. 2902-03.

Decision – Equity Linked Convertible Debt

The Commission finds this issue in favor of KCP&L and GMO. Given that GPE acted in the best interests of both KCP&L and GMO at a time when the country was in the midst of a severe economic recession, and the pricing terms were as favorable as could be obtained, there is no sound reason for accepting Staff's 245 basis point adjustment in the cost of the Equity Units.

D. Off-System Sales

Findings of Fact – Off-System Sales

How should off-system sales margins be determined?

433. GMO has more power available for off-system sales ("OSS") now that Iatan 2 is on-line.

434. The Company used 2009 normalized test-year data produced through the use of the MIDAS™ model to set rates for off-system sales. This process was also used to normalize test-year fuel and purchased power costs.[590]

435. In this case the Commission accepted the agreement of the parties to use 2009 as the test year, with a true-up as of December 31, 2010.[591]

436. Staff proposes to set rates for off-system sales using historical data from 2007-2008 based upon its view that GMO's off-system sales for the last two years did

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[590] Ex. GMO 10, pp. 5-9.

[591] *Order Approving Nonunanimous Stipulation and Agreement, Setting Procedural Schedule, and Clarifying Order Regarding Construction and Prudence Audit* at 2, ¶ 3 (Aug. 18, 2010).

not represent an adequate level of off-system sales. Consequently, Staff witness V. William Harris recommended that sales levels from 2007-2008 be used.[592]

437. Substantial changes have occurred in the wholesale electricity market in the prices for electricity from 2007-2009 to the present time. The average market price during 2007-2008 was approximately $50/MWh, and since that time, the average price has dropped to approximately $30/MWh.[593]

438. Data supplied by Company witness Michael Schnitzer of the NorthBridge Group reviewed SPP-North sport market prices for electricity, and indicated that electricity prices were higher in 2007-2008 than in the period from 2009 to the present.[594] For example, the average around-the-clock price of electricity in SPP-North for the second quarter of 2007 and 2008 were $49.79 and $61.23, respectively, whereas the average price for the same commodity in the second quarter of 2010 was $30.40.[595]

439. Additionally, the operating costs of the units from which excess generation is sold in the wholesale market have risen since 2007-2008, and, consequently, with higher expenses and lower prices, margins have decreased.[596]

440. With the expiration of GMO's purchased power contract with NPPD and the addition of 153 MW from GMO's share of Iatan 2, off-system sales in 2011, even

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[592] Ex. GMO 210, pp. 77-78; Ex. GMO 220, pp. 2-4.
[593] Ex. GMO 11, p. 16.
[594] Ex. KCP&L 122.
[595] Ex. KCP&L 122, p. 1.
[596] Ex. GMO 11, p. 16.

based on a test year of 2009 (as trued-up), will not be similar to the 2007-2008 historical levels utilized by Staff.[597]

441. Aquila and GMO/KCP&L had different interpretations of what was permissible under their respective Federal Energy Regulatory Commission ("FERC") tariffs regarding the use of network transmission service to facilitate off-system sales.[598]

442. In 2005 FERC clarified that it is not appropriate for a utility to use network transmission service to facilitate purchases of energy for resale at a profit, and this largely eliminated GMO's ability to purchase power for resale.[599] Since the acquisition of Aquila by Great Plains Energy in 2008, both Aquila and GMO/KCP&L have adhered to FERC policy which has contributed to a decline in off-system sales.[600]

443. Staff's recommendation to use 2007-2008 historical data to set off-system sales is not based upon any analysis or research concerning energy prices in the SPP-North region.[601] Staff's witness Mr. Harris failed to observe that natural gas prices have declined since 2007-2008, which is significant since electricity prices in SPP-North are primarily the product of natural gas prices.[602] Mr. Harris also failed to note that the region has experienced less demand for wholesale power as a result of the economic recession.[603]

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[597] Ex. GMO 11,p. 17.
[598] Tr. 4221-22.
[599] Ex. GMO 6, p. 6; Tr. 4425-26.
[600] Tr. 4221-22; Tr. 4225-27.
[601] Tr. 4228-29.
[602] Ex. GMO 6, p. 6; Ex. KCP&L 58, pp. 6-7.
[603] Ex. GMO 6, p. 6.

444. Staff did not conduct any research regarding the use of network transmission service to facilitate off-system sales, and its witness was not familiar with FERC policies that govern network transmission service.[604]

445. Staff's proposal to set rates for off-system sales based upon data that does not reflect test-year data from 2009, as trued-up, or the decline in electricity prices since 2007-2008 is contrary to the Commission's traditional reliance upon a test-year in deciding general rate cases.

<u>Conclusions of Law – Off-System Sales</u>

48. Staff's recommendation to use 2007-2008 data, instead of 2009 test-year data is inconsistent with the Commission's preference for test-year data. The purpose of a test year is to provide a period for which complete data is available in order to permit review by Staff and others, as well as to provide the Commission with a basis to estimate future revenue requirements.[605] While information other than the "strict test year" concept is permitted, such data typically reflects "a change that actually took place during or after the test year" or "a forward-looking test year."[606]

49. Missouri has followed the test-year concept and has not departed from it, except to account for future developments or to normalize a level of revenue or expense that will be "most representative of future expenses."[607]

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604 Ex. GMO 6, p. 6; Tr. 4230-31.
605 *See*, C. Phillips, *The Regulation of Public Utilities*, (1993) at 196.
606 *Id*.
607 *In re Union Elec. Co.*, *Report and Order*, File No. ER-2010-0036 (May 28, 2010) at 50. *See*, *State ex rel. Missouri Power & Light Co. v. PSC*, 669 S.W.2d 941, 945 (Mo. App. W.D. 1984); *State ex rel. Missouri Public Service Co. v. Fraas*, 627 S.W.2d 882, 887-90 (Mo. App. W.D. 1981).

50. FERC has clarified that it is not appropriate for a utility to use network transmission service to facilitate purchases of energy for resale at a profit.[608] FERC stated in this case that utilities are not to use network service to advance their own OSS, and that network transmission service should only be used to satisfy a utility's native load. In Mid-American the Audit Report of FERC Staff described a variety of irregularities, which the utility settled by agreeing to construct $9.2 million of previously unplanned transmission upgrades, and to forego recovery of all costs associated with these projects for six years from the time the assets are placed in service.[609] FERC approved the Audit Report "in its entirety without modification."[610]

51. Regarding transmission service and off-system sales, the Audit Report stated: "MidAmerican's wholesale merchant function (Electric Trading) used network transmission service to deliver short-term energy purchases to a generator in its control area when it concurrently made short-term off-system sales. Electric Trading is allowed to use network transmission service to deliver energy from designated network resources and to deliver economy energy purchases to their network load. However, Electric Trading may not use network transmission service to deliver energy that is used to support off-system sales."[611]

[608] *See*, *Mid-American Energy Co.*, 112 FERC ¶61, 346, 2005 WL 2430182 (2005).
[609] *Id*. at 2-3.
[610] *Id*. at 3.
[611] *Id*. at 6.

Decision – Off-System Sales

Staff's proposal to set OSS based on data from 2007-2008 is beyond the test year, is not representative of current energy prices, and is rejected. The Company's method of calculating the OSS using the test year 2009 data is adopted.

III. Expenses

A. Fuel and Purchased Power Expense

How should natural gas costs be determined?

How should spot market purchased power prices be determined?

Findings of Fact – Fuel and Purchased Power Expense

446. No party opposed the forecasting process proposed by KCP&L/GMO Witness W. Edward Blunk for natural gas costs. Under this process, natural gas prices are based on the first of the month index price published in Platt's Inside FERC, as well as NYMEX closing prices related to Henry Hub natural gas futures contracts.[612]

447. Mr. Blunk stated in his Direct Testimony that the Companies expected to true-up 2010 natural gas prices for their cost of service to actual prices at the conclusion of the case.[613]

[612] Ex. KCP&L 10; Ex. GMO 7.
[613] Ex. KCP&L 10, p.14; Ex. GMO 7, p. 10.

448. In True-Up Direct Testimony, KCP&L Witness Burton L. Crawford confirmed that natural gas costs were updated to reflect the actual monthly purchase prices for January through December 2010.[614]

449. At the hearing there was no cross-examination for Mr. Blunk.[615] Similarly, no party offered pre-filed true-up rebuttal testimony opposing the true-up direct testimony filed by Mr. Crawford in each of the cases.

450. Mr. Weisensee testified in true-up rebuttal testimony that KCP&L had been working closely with Staff in the reconcilement process, that there was a need to update the respective revenue deficiencies, that the process would continue through the filing of Staff's final reconciliation on March 2, and that KCP&L's revised position would be reflected in that reconciliation.[616]

451. GMO's true-up testimony indicates an overall revenue deficiency of $65.2 million for MPS and $23.2 million for L&P.[617] The March 2, 2011 reconciliation reflects GMO's further revisions showing a $65,967,384 deficiency for MPS and a $23,125,151 deficiency for L&P.

452. GMO recommends using the MIDAS™ model to forecast spot market electricity prices.[618]

453. MIDAS™ is a proprietary production cost model that includes a large amount of data including information supplied by electric utilities in their FERC Form 1 filings, as well as data submitted to the U.S. Department of Energy's Energy Information

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614 Ex. KCP&L 111, p. 2; Ex. GMO 56, p. 2. (These costs are reflected in Sch. JPW 2010-9, attached to the True-Up Direct testimonies of John P. Weisensee, Ex. KCP&L 117 and Ex. GMO 59.)
615 Tr. 3198.
616 Ex. GMO 60, p. 6.
617 Ex. GMO 115, p. 1.
618 Ex. GMO 10, p. 2.

Administration and to the Continuous Emissions Monitoring System ("CEMS")[619] of the U.S. Environmental Protection Agency.[620] Using this data, the MIDAS™ model is designed "to simulate the wholesale power markets to develop an hourly price of power for the wholesale market. That information then gets fed also into the model and another portion of the model to determine the normalized level of fuel and purchase power for the company."[621] Portions of GMO's model are "based on the historical experience" of GMO, the model is also "based on a production simulation for the Eastern Interconnect."[622]

454. Staff's model relies exclusively on historical data.[623] Staff employs a statistical calculation based upon the historical weather adjusted loads and the truncated normal distribution curve to represent the hourly purchased power prices in the spot market.[624] Staff obtained the actual hourly non-contract transaction prices from the companies and used this data in its calculation.[625] Staff used the combined data from both KCP&L and GMO to reflect the market that exists in this region.[626] Staff's method yields a spot energy price for each hour of the year.[627] This data set, containing 8,760 hourly spot energy prices, is then used as one of the inputs to Staff's production cost model.[628]

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[619] Tr. 3205; Ex. GMO 10, p. 3.
[620] Tr. 3205-06.
[621] Tr. 3205.
[622] Tr. 3203-04.
[623] Tr. 3215.
[624] Ex. KCP&L 210, pp. 77-78; Ex. GMO 210, pp. 84-85; Ex. GMO 231, pp. 1-2.
[625] Ex. KCP&L 210, pp. 77-78; Ex. GMO 210, pp. 84-85; Ex. GMO 231, pp. 1-2.
[626] Ex. KCP&L 210, pp. 77-78; Ex. GMO 210, pp. 84-85; Ex. GMO 231, pp. 1-2.
[627] Ex. KCP&L 210, pp. 77-78; Ex. GMO 210, pp. 84-85; Ex. GMO 231, pp. 1-2.
[628] Ex. KCP&L 210, pp. 77-78; Ex. GMO 210, pp. 84-85; Ex. GMO 231, pp. 1-2.

455. Staff only uses KCP&L and GMO data, and no data from any other utility to arrive at a recommendation of spot market prices.[629] Staff's model "does not consider the impact of other market price drivers, such as natural gas prices, environmental allowances or other factors of electric production."[630]

456. Ms. Maloney testifying for Staff indicated that she was not familiar with all of the inputs to the MIDAS™ model and that she had never worked the model herself.[631]

Conclusions of Law – Fuel and Purchased Power Expense

52. It is within the Commission's discretion and within its area of expertise to determine the methods to set rates regarding off-system sales, as well as fuel and purchased power.[632]

Decision – Fuel and Purchased Power Expense

Two issues related to fuel and purchased power expense were presented to the Commission with regard to GMO.

The first issue does not appear to be in controversy. No party opposed the forecasting process proposed by KCP&L Witness W. Edward Blunk for natural gas costs. Under this process, natural gas prices are based on the first of the month index price published in Platt's Inside FERC, as well as NYMEX closing prices related to

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[629] Tr. 3217.
[630] Ex. KCP&L 16 and Ex. GMO 11.
[631] Tr. 3217-19.
[632] *State ex rel. Missouri Gas Energy v. PSC*, 186 S.W.3d 376, 382 (Mo. App. W.D. 2005).

Henry Hub natural gas futures contracts. The Commission adopts this method of determining natural gas costs.

The second issue the Commission must address how the spot market purchased power prices shall be determined. GMO asks the Commission to use its MIDAS™ model which forecasts spot market electricity prices. Staff proposes to use its 1996 model which uses only historical market prices and loads.

The MIDAS™ model contains historical information, including the experience of GMO, but is also based on a production simulation for the entire Eastern Interconnection. This model includes an extensive amount of data, both historical and forecasted.

Staff's model relies only upon historical data of KCP&L. It relies on no data from any other utility and does not use any projected data.

The Commission must set the level of fuel expense and purchased power expense for GMO in this case, and it prefers to use the greatest amount of information available to set spot market prices for determining that expense. Given the multitude of variables that affect electricity prices, the Commission accepts the MIDAS™ model as superior in many instances because it considers a vast amount of information, both historical and projected.

Staff wants only historical data from GMO to be considered arguing that use of the traditional historical test year prevents the Commission from relying on forecasted data. To the contrary, the Commission is afforded considerable discretion in setting rates, and in this instance determines that the utilization of a nationally recognized tool like the MIDAS™ model is appropriate to determine spot market prices in setting just and reasonable rates.[633]

B. Merger Transition Cost Recovery

What, if any, is the appropriate amount of merger transition costs to include in rates in this case?

Findings of Fact –Transition Cost Recovery

457. In July of 2008, the Commission approved the acquisition of Aquila by Great Plains Energy Incorporated ("GPE").[634]

458. The acquisition of Aquila, Inc. was consummated on July 14, 2008.

459. In consummating that transaction, GPE incurred certain costs. These costs have been labeled as either transaction costs or transition costs. "[T]ransaction costs include investment bankers' fees, as well as consulting and legal fees associated with the evaluation, bid, negotiation and structure of the transaction."[635] Transition costs, on the other hand, are "costs incurred to successfully coordinate and integrate the utility operations of KCP&L and GMO . . . . These costs include non-executive severance costs for employees terminated as a result of the merger, facilities integration

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[633] In File No. ER-2010-0355 regarding GMO's sister company, KCP&L, the Commission decided this issue in favor of using the numbers recommended by Staff for fuel expense. Even though the management of the two companies is the same, the circumstances of that case were different and warranted a different result. Specifically, KCP&L abandoned its model in the KCP&L case in favor of Staff's and that fact helped persuade the Commission that Staff's model was more reliable in that instance. No similar abandonment has occurred with regard to GMO.

[634] *Report and Order, In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Aquila, Inc., for Approval of the Merger of Aquila, Inc., with a Subsidiary of Great Plains Energy Incorporated and for Other Related Relief*, File No. EM-2007-0374 (issued Jul. 1, 2008). Hereinafter referred to as "Merger Order."

[635] Ex. KCPL 35, p. 6.

costs, and incremental third-party and other non-labor expenses incurred to support the integration of the companies."[636]

460. The Commission considered and addressed the proper treatment of transition cost recovery in the Merger Order.[637]

461. In Missouri, it is well established that there is a lag between when a cost or revenue is incurred and when that cost or revenue is reflected in rates. This is known as regulatory lag.[638]

462. As a result of regulatory lag, if a utility experiences a cost decrease, there is a lag in time until that reduced cost is reflected in rates. During that lag, the Company shareholders reap, in the form of increased earnings, the entirety of the benefit associated with reduced costs. The Company shareholders also reap, in the form of decreased earnings, the entirety of the loss associated with increased costs.

463. The Commission "authorize[d] KCP&L and Aquila to defer transition costs to be amortized over five years."[639]

464. The Commission qualified its authorization by stating that, "The Commission will give consideration to . . . [the transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCP&L and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of

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[636] Merger Order at 4.

[637] *Report and Order, In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Aquila, Inc., for Approval of the Merger of Aquila, Inc., with a Subsidiary of Great Plains Energy Incorporated and for Other Related Relief*, File No. EM-2007-0374 (issued Jul. 1, 2008). Hereinafter referred to as "Merger Order."

[638] Ex. KCP&L 210, p. 190.

[639] Merger Order at 241.

service expenses in future rate cases."[640] The Commission contemplated that the recovery would only happen if the synergy savings were greater than the costs to achieve those savings.[641]

465. With regard to the recovery of transition costs, the Merger Order contains a summary of what KCP&L and Aquila had originally requested. That summary states in part, "This period would begin with the first rate cases post-transaction for Aquila and KCP&L subject to 'true up' of actual transition . . . costs in future cases."[642]

466. In the current rate cases, the Companies seek to recover the merger transition costs in rates over five years beginning with rates effective from this case.

467. The Companies projected that over the first five-year period, the total operational synergies projected to result from the merger were $305 million, and $755 million over the first 10-year period.[643] The Commission found these estimates to be "accurate, realistic and achievable," and also recognized that "the synergies actually realized from the merger have a very high probability of exceeding the [company's] estimates."[644] The Commission also found that there was "no detriment to customers" by allowing the companies to recover synergy savings through regulatory lag.[645]

468. KCP&L and GMO began to retain synergy savings, in the form of reduced costs, immediately upon the closing of the acquisition. Given that KCP&L and GMO did

[640] Merger Order at 241, footnote 930.
[641] Merger Order at 240.
[642] Merger Order at 239.
[643] Merger Order at 234.
[644] Merger Order at 238.
[645] Merger Order at 120 and 238; Tr. 3473.

not have its next rate case completed until September 1, 2009, the Great Plains shareholders retained the entirety of these synergy savings for that period of time.[646]

469. The Companies developed and maintained a Synergy Tracking Model which demonstrated that the merger synergy savings for non-fuel operations and maintenance expense exceed the amortization of merger transition costs.[647]

470. The Companies also developed and maintained a synergy project charter database to track synergies not ordered to be tracked by the Commission.[648]

471. Staff performed an analysis of both the Commission ordered synergy savings tracking model and KCP&L created synergy project charter database. Staff's analysis showed that the amount of synergies in the synergy project database exceeded those in the Commission-ordered tracking system.[649]

472. As of September 1, 2009, the shareholders of KCP&L and GMO had realized over $59.3 million in synergy savings.[650]

473. As of June 30, 2010, the shareholders of KCP&L and GMO had realized approximately $121 million in retained synergy savings.[651]

474. KCP&L and GMO project that total synergy savings through 2013 will be $344 million.[652] Of that amount, KCP&L and GMO project that ratepayers will receive $150 million.[653]

646 Ex. KCP&L 230.
647 Ex. KCP&L 35; Ex. KCP&L 230, p. 7.
648 Ex. KCP&L 230, pp. 7-8; Ex. KCP&L 35, pp. 7-10
649 Ex. KCP&L 230, pp. 7-8.
650 Ex. KCP&L 230, p. 12.
651 Ex. KCP&L 230, p. 9.
652 Ex. KCP&L 230, p. 14.
653 Ex. KCP&L 230, p. 14.

475. The synergy savings exceed the level of the amortized costs.[654]

476. The Companies stopped the deferral of transition costs as of December 31, 2010.

477. No party challenged the reasonableness or prudence of incurring the merger transition costs. In addition, Staff's witness stated that the transition costs incurred by the company were not unreasonable or imprudent.[655]

478. Staff did an analysis of the Companies' Administrative & General ("A&G") expenses and other electric utilities in the region.[656] Staff's analysis indicates that on a combined company basis, KCP&L and GMO have the highest A&G expenses per customer, per megawatt hour sold and per dollar of operating revenue.[657]

<u>Conclusions of Law – Transition Cost Recovery</u>

53. In the Merger Order, the Commission expressly precluded any recovery of transaction costs,[658] but the Commission reserved consideration of recovery of the transition costs when it said:

> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCP&L and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases.[659]

[654] Ex. KCP&L 35, pp. 4, 7-10; Ex. KCP&L 230, pp. 7-8; Tr. 3472.
[655] Tr. 3448, 3470, 3489.
[656] Ex. KCP&L 231, p. 16.
[657] Ex. KCP&L 231, pp. 16-17.
[658] Merger Order at 239-240.
[659] Merger Order at 241, footnote 930.

54. While leaving the possibility for future recovery of transition costs, the Commission expressly reserved that decision for a "later proceeding" stating in the ordered paragraphs that:

> 13. Nothing in this order shall be considered a finding by the Commission of the value for ratemaking purposes of the transactions herein involved.
>
> 14. The Commission reserves the right to consider any ratemaking treatment to be afforded the transactions herein involved in a later proceeding.[660]

55. With regard to the recovery of transition costs, the Merger Order contains a summary of what KCP&L and Aquila had originally requested. That summary states in part, "This period would begin with the first rate cases post-transaction for Aquila and KCP&L subject to 'true up' of actual transition . . . costs in future cases."[661]

56. In the Merger Order, the Commission "authorize[d] KCP&L and Aquila to defer transition costs to be amortized over five years."[662]

57. The Companies accumulated all transition costs consistent with the Merger Order. The Commission concludes that the Companies have complied with the Merger Order as it relates to recovery of transition costs.

58. The Commission further concludes that the Merger Order contemplated the Companies would be permitted to retain synergy savings through regulatory lag.

59. "The PSC is not bound by ***stare decisis*** based on prior administrative decisions, so long as its current decision is not otherwise unreasonable or unlawful."[663]

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[660] Merger Order at 284.
[661] Merger Order at 239.
[662] Merger Order at 241.
[663] *State ex rel. Ag Processing, Inc. v. Public Service Commission*, 120 S.W.3d 732, 736 (Mo. banc 2003).

Thus, even had the Merger Order not expressly reserved any questions regarding ratemaking treatment to a "later proceeding," this Commission would still have the ability to consider the issue without being bound by the previous Commission's decision.

60. Generally, conflicting provisions "must be read together, and so harmonized as to give effect to [all] when this can be reasonably and consistently done."[664]

Decision – Transition Cost Recovery

Staff and the Industrials argue that because retained synergy savings resulting from regulatory lag exceeded the amount of transition costs, recovery of the transition costs would constitute double recovery and therefore be unreasonable and inequitable. In response, the Companies argue that the Commission created an expectation in its Merger Order, that so long as the transition costs were deemed reasonable and prudent, and the Companies could demonstrate that synergy savings exceed the level of amortized transition costs, the Companies would be permitted to recover the transition costs in rates.

No party to this proceeding has challenged the reasonableness and prudence of the claimed transition costs or challenged the amount of synergy savings. While true that the Companies' shareholders have enjoyed the benefit of regulatory lag in retaining synergy savings since the merger was consummated, the Commission finds that this outcome was specifically contemplated in its consideration of the appropriate treatment for synergy savings in the merger case and as set out in the Merger Order. The

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[664] *State ex rel. McClellan v. Godfrey*, 519 S.W.2d 4, 8 (Mo. banc 1975) (citing to *Straughan v. Meyers*, 187 S.W. 1159 (Mo. 1916).

Commission also finds that it specifically contemplated that synergy savings would be higher than predicted.

This outcome does not constitute double recovery because the costs were not authorized to be recovered, but rather were deferred by the Merger Order to be considered in a later rate case – this case. The Commission expected that recovery would only occur if the Companies incurred the costs prudently and reasonably and demonstrated that the synergy savings were more than the transition costs. The Companies have done this.

To read the Merger Order as Staff and the Industrials would read it makes the order contradict itself. If the transition costs could not be recovered unless they were more than the synergy savings, yet they could not be recovered until netted against the synergy savings, there would be no costs to defer or to amortize over a five-year period.

Staff also argues that the A&G expenses of the Companies were higher than average and attempted to make a connection to the transition costs being unreasonable. The Commission gives little weight to that argument since Staff's witness testified that these transition costs were not incurred unreasonably or imprudently. The Commission concludes that the transition costs were reasonable and prudent.

Staff also argues that the companies should have begun amortizing these costs in the previous rate cases per the Merger Order.[665] At first glance, the Merger Order does imply that the five-year amortization will begin from the first rate case after the

[665] Ex. GMO 210, p.221.

transaction is consummated.[666] However, that statement is just a restatement of what the Companies were proposing. The Commission never specifically orders that treatment. Furthermore those rate cases were resolved through settlement and this issue was not addressed in that settlement so the issue never came before the Commission for consideration. Thus, this is the first opportunity for the amortizations to begin and Commission determines they will be amortized over five years beginning with this rate case.

The evidence in this case supports the Commission's original findings in the Merger Order that the Companies should be permitted to recover the merger transition costs in rates over five years beginning with rates effective from this case.

C. Rate Case Expense

What is the appropriate level of rate case expense to include in this proceeding?

Findings of Fact – Rate Case Expense

479. KCP&L and GMO seek to recover rate case expenses incurred through the true-up date of December 31, 2010, of $4,593,427 in the KCP&L case and $3,177,725 for GMO[667] the case (rounded to $7.7 million total rate case expense).[668]

480. Per an informal agreement with Staff, a substantial amount of rate case expense that occurred after the April 30, 2009 true-up date of the 2009 KCP&L (ER-2009-0089) and GMO rate cases (ER-2009-0090) was transferred to the current

[666] Merger Order at 239.
[667] This breaks down to $2,001,855 for MPS and $1,175,870 for L&P.
[668] Ex. KCP&L 309, p. 9.

rate case.[669] Approximately 50% of the total rate case costs in the 2009 KCP&L rate case and 40% in the GMO 2009 rate case were recorded after the true-up in those cases and these costs were transferred to the current rate cases.[670]

481. Of the $7.7 million total, $1.6 million is deferred rate case expense from those previous rate cases. The total additional rate case expense sought for these cases, ER-2010-0355 and ER-2010-0356, through the true-up period is $6.1 million.

482. Staff does not object to the Companies' proposal to defer rate case expense incurred after December 31, 2010, for consideration in a future rate case so long as Staff has an opportunity to review those expenses for prudence and reasonableness in that subsequent case.[671] No other party objected to this proposal.

483. Staff's detailed requests for rate case expense disallowances appeared in the true-up portion of the proceeding. Staff claims this was because it did not receive adequate supporting documentation from the Companies on a timely basis.[672]

484. On June 25, 2010, Staff requested all rate case expense invoices from KCP&L in Data Request ("DR") No. 141.[673] KCP&L responded on July 12, 2010, indicating that the request was "voluminous" and "If a specific vendor invoice or invoices is required, please advise."[674] Staff followed up with DR 141.1 on September 3, 2010, with a narrower request for invoices over $5,000.[675] KCP&L responded on

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669 Ex. KCP&L 63,p. 61.
670 Ex. KCP&L 64, pp. 22-23; Ex. GMO 43, p. 4.
671 Ex. KCP&L 310, p. 2.
672 Ex. KCP&L 309, p. 2.
673 Ex. KCP&L 291, Ex. KCP&L 231, p. 27.
674 Ex. KCP&L 291.
675 Ex. KCP&L 231, p.27.

September 23, 2010, by providing “face sheets” for certain legal expenses.[676] These face sheets provided very little information about the charges.

485. Face sheets were provided in prior cases and if additional detail was required, the company provided it. The face sheets were timely provided in response to Staffs request for legal invoices. When additional detail was requested, the detail was also provided in a timely manner with redactions for privileged material made.[677]

486. Staff issued DR 141.2 on November 3, 2010, seeking full invoice detail for the invoices.[678] KCP&L responded on November 24, 2010.[679] On November 24, 2010, Staff expanded its invoice request with DR 141.3 which asked for all invoices over $1,000.[680] KCP&L provided the invoices on December 30, 2010.[681] KCP&L made no objection or assertion of privilege to DR 141.3.[682]

487. Staff initially advocated disallowance of all legal expenses from vendors Stinson, Morrison & Hecker; Schiff Hardin; Pegasus Global; and Morgan, Lewis & Bockius. After reviewing the invoices, however, Staff changed its position in its true-up testimony to advocate a disallowance of all legal expenses of Morgan, Lewis & Bockius; an adjustment to rate case expenses charged by Schiff Hardin; an adjustment for NextSource; and an adjustment for services of The Communication Counsel of America.[683]

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676 Ex. KCP&L 231, p. 27; and Ex. KCP&L 292.
677 Tr. 3640-42.
678 Ex. KCP&L 231, p. 28.
679 Ex. KCP&L 231, p. 28.
680 Ex. KCP&L 231, p. 28.
681 Ex. KCP&L 231, p. 28.
682 Ex. KCP&L 231, p. 28.
683 Ex. KCP&L 309, pp. 2-9.

488. The hourly rates of Morgan, Lewis & Bockius were significantly higher than the highest paid attorney from a Missouri firm in this case.[684] The Kansas Corporation Commission also found this vendor's services to be duplicative. The KCC noted the duplicative nature of Ms. Barbara Van Gelder's services for the firm and noted she was retained to cross-examine one particular Staff witness, but that four capable attorneys for KCP&L were in the hearing room while she did so.[685]

489. During the cross-examination on rate case expense, two external counsel and two internal counsel were present in the hearing room for KCP&L and GMO.[686] Also, during the April 2010 proceedings related to File No. EO-2010-0259, several KCP&L outside attorneys were present at one time or another, including Mr. Riggins, former general counsel at KCP&L, an attorney from SNR Denton, an attorney from Fischer & Dority, an attorney from Stinson, Morrison & Hecker, and an attorney from Morgan, Lewis & Bockius.

490. Morgan Lewis was employed in Commission File No. EO-2010-0259 which has been consolidated with the current rate case so that the information could be readily shared between files. File No. EO-2010-259 was an on-the-record proceeding to determine the status of Staff's Iatan 1 audit. That proceeding was important to the rate case in that the Staff was to explain every aspect of the Iatan 1 construction audit. That audit is part of this rate case and the data requests in that docket are linked to this rate case.

[684] Ex. KCP&L 309, pp. 2-9.
[685] Ex. KCP&L 231, Sch. 5.
[686] Tr. 3629-3632.

491. With regard to the invoices related to Schiff Hardin, Staff proposes to disallow a portion of the expenses by, in effect, discounting the rate charged by Schiff Hardin attorneys to the hourly rate charged by Pegasus Global Holdings.[687] Staff claims this discount is reasonable "given the number of attorneys retained in these proceedings" it is reasonable to "assume" there was duplicative legal services.[688] Staff also reasons that because Pegasus Global Holdings provided services to KCP&L and GMO for expert testimony on the prudence of Iatan, and because Schiff Hardin provided expert testimony on the prudence of Iatan, that it is reasonable to assume there is some duplication of services.

492. Schiff Hardin's hourly rates for attorneys and consultants were almost two times that of Pegasus' fees.[689]

493. The hourly rate charged by Schiff Hardin in the KCC case exceeded those for experienced attorneys in the Kansas City metropolitan area.[690]

494. The Kansas Corporation Commission heard many of the same issues that are before this Commission including rate case expense.[691] The KCC found that the expenses requested for Schiff Hardin were "particularly troubling."[692] And, while the KCC noted the case contained complex issues concerning the construction of a major

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687 Ex. KCP&L 309, p. 6.
688 Ex. KCP&L 309, pp. 6-7.
689 These highly confidential numbers are provided at Ex. KCP&L 309, p. 7.
690 Ex. KCP&L 231, Sch. 5-13.
691 Docket No. 1O-KCPE-415-RTS, Order dated Nov. 22, 2010 (KCC Order).
692 Ex. KCP&L 231, Sch. 5-13.

generating facility, it found it "unreasonable to require ratepayers to be responsible for the entire rate case expense costs being sought by KCP&L."[693]

495. KCP&L and GMO did not object to any of Schiff Hardin's bills for legal services or any experts' invoices, or ask them to make any adjustments or corrections.[694]

496. In its last litigated rate case, KCP&L in-house attorneys shared in a great deal of the work associated with litigating that case. Those attorneys, whose salary and benefits are already recovered through rates, litigated issues associated with policy, off-system sales margins, Hawthorn 5 settlement costs and uranium enrichment overcharges.[695]

497. At least six outside attorneys with four different firms entered an appearance for KCP&L and GMO in this case.[696]

498. Regarding NextSource, Staff initially removed "all dollars KCP&L has included in rate case expense related to Mr. Giles' services as an independent contractor."[697]

499. Mr. Giles is currently a regulatory consultant to KCP&L. He has been in that capacity since his retirement in July 2009 from his position as KCP&L's Vice President, Regulatory Affairs. His responsibilities "include assisting and advising the current Senior Director, Regulatory Affairs."[698]

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[693] Ex. KCP&L 231, Sch. 5.
[694] Tr. 267-268.
[695] Ex. KCP&L 1217.
[696] *See generally,* Hearing Transcripts.
[697] Ex. KCP&L 9, p. 6, quoting Ex. KCP&L 230, p. 21.
[698] Ex. KCP&L 24, p. 1.

500. At the time of his testimony, Mr. Blanc was the current Senior Director, Regulatory Affair, assuming many of the duties that Mr. Giles' did before his retirement.

501. Mr. Giles' salary and benefits were included in the rates that resulted from GMO's last rate case (ER-2010-0090) and have been in GMO's revenue requirement used to set its electric utility rates for many years. While Mr. Giles' job duties are not exactly the same as Mr. Blanc's as Mr. Blanc's his work is somewhat duplicative.[699]

502. The KCC did not include any expenses for NextSource (Mr. Giles) because KCP&L could not explain why its own employees could not perform the work done by this vendor.[700]

503. In the true-up case, with regard to Mr. Giles' consulting fees, Staff proposed to reallocate the total adjustment between KCP&L and GMO using the payroll factors for labor expenses used in Staff's payroll annualization.[701] Staff recommends allocating the disallowance within the true-up to 67% to KCP&L, 23% to GMO-MPS and 10% to GMO-L&P.

504. Staff also proposes removing the costs associated with The Communication Counsel of America from rate case expense. The services provided by The Communication Counsel of America related to witness development and coaching services. These are routine tasks typically performed by retained counsel, internal or otherwise.[702] Specifically, The Communication Counsel of America was engaged to prepare the Companies' Iatan prudence witnesses.

[699] Ex. KCP&L 230, p.12.
[700] Ex. KCP&L 231, Sch. pp. 5-11.
[701] Ex. KCP&L 309, p. 8.
[702] Ex. KCP&L 309, p. 8.

505. The CCA also trained KCP&L witnesses for the KCC hearing.[703] The KCC disallowed expenses related to The Communication Counsel of America as unjust and unreasonable.[704] While the KCC noted witness preparation as important it stated that, "such preparation is routinely part of the service counsel performs before a hearing."[705]

506. The Companies' shareholders benefit from having good advocates and experts for rate cases. Specifically, the Companies receive the benefit of a greater recovery of [the Companies'] costs . . . for decades to come".[706]

507. The Companies' ratepayers benefit from having good advocates and experts for rate cases. Specifically, the ratepayers receive the benefit of reduced costs of borrowing for the Companies if the Companies get a sufficient recovery of assets in rates.[707]

508. The benefits to shareholders and ratepayers of having good advocates and experts are more significant with a large dollar and complex issue such as the Iatan prudence issues.[708]

509. KCP&L and GMO relied heavily on the use of outside consultants for the litigation of these cases. The following consultants each filed testimony in this matter

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[703] Ex. KCP&L 231, Sch. p. 5-11.
[704] Ex. KCP&L 231, Sch. p. 5-11.
[705] Ex. KCP&L 231, Sch. p. 5-11.
[706] Tr. 3647.
[707] Tr. 3648-3649.
[708] Tr. 3648.

and were charged to Missouri rate case expense: Chris Giles;[709] Gary Goble;[710] Samuel Hadaway;[711] Steven Jones;[712] Larry Loos;[713] Daniel Meyer;[714] Kris Nielsen;[715] Paul Normand;[716] Kenneth Roberts;[717] Michael Schnitzer;[718] John Spanos;[719] and Ken Vogl.[720]

510. Staff has no objection to KCP&L and GMO amortizing its rate case expense over a two-year period and deferring expenses incurred after the December 31, 2010, true-up date with Staff review for prudence and reasonableness.[721]

511. The KCC ordered a four-year amortization period for rate case expense.[722]

512. KCP&L and GMO have no plans to file their next rate cases.[723]

513. Some adjustment in the amortization period for rate case expense is reasonable. The Commission finds that a three-year amortization period is sufficient.

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709 Exs. KCP&L 24 and 25.
710 Ex. KCP&L 26.
711 Exs. KCP&L 27-29.
712 Ex. KCP&L 38.
713 Exs. KCP&L 39-41.
714 Exs. KCP&L 43-45.
715 Exs. KCP&L 46.
716 Exs. KCP&L47-49.
717 Exs. KCP&L 50-53.
718 Ex. KCP&L 58.
719 Exs. KCP&L 59-61.
720 Ex. KCP&L 62.
721 Ex. KCP&L 310, p. 2.
722 Docket No. 1O-KCPE-415-RTS, Order dated Nov. 22, 2010, ordered paragraph R, p. 140.
723 Tr. 3373.

Conclusions of Law – Rate Case Expense

61. The Commission can disallow costs that are not of benefit to ratepayers, and there does not need to be a showing of bad faith or abuse of discretion for the Commission to disallow costs.[724]

62. In File No. GR-2004-0209, the Commission reduced the amount of rate case expense incurred by Missouri Gas Energy (MGE) by the disallowance of certain attorney fees. In that Report and Order, the Commission recognized the unfairness of charging ratepayers high attorney fees.[725]

63. In a 1993 Missouri-American decision, the Commission attempted to provide some definition by which to measure whether rate case expense is necessary and prudently incurred. In that case the Commission based its decision on whether actual evidence exists of cost containment.

> The Commission must continue to look to the record for evidence in support of rate case expense and in this case that evidence is lacking. Disallowing all expense, or perhaps even disallowing any prudently incurred rate case expense could be viewed as violating the Company's procedural rights. The Commission does not want to put itself in the position of discouraging necessary rate cases by discouraging rate case expense. ***The operative words here, however, are necessary and prudently incurred. The record does not reflect efforts at cost containment and consequently it does not support that these expenses have been prudently incurred.***[726]

Absent evidence of cost containment, the Commission in that case disallowed approximately one-third of Missouri American's rate case expense.

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[724] *State ex rel. Laclede Gas Co. v. Public Serv. Comm'n*, 600 S.W.2d 222, 228-29 (Mo. App., W.D. 1980), *app. dis'd*, 449 U.S. 1072, 101 S.Ct. 848, 66 L.Ed.2d 795 (1981); *State ex rel. Southwestern Bell Tel. Co. v. Public Serv. Comm'n,* 645 S.W.2d 44, 55-56 (Mo. App., W.D. 1982).

[725] *Report and Order*, File No. WR-93-212 (issued November 18, 1993). (Emphasis Added.)

[726] *Id.*

Decision – Rate Case Expense

KCP&L and GMO ask that they be allowed to recover the entirety of their $7.7 million rate case expense (including $1.6 million from the previous cases and $6.1 million combined for the current cases) in rates amortized over a two-year period with any rate case expense incurred after the true-up period to be deferred to the next rate cases. In response, Staff and MEUA propose to disallow a certain portion of those costs. Staff sets out specific disallowances while MEUA proposes an across the board 33% reduction.[727] In addition, MEUA suggests that the Commission amortize the rate case expense over a four-year period instead of a two-year period.[728]

The Companies were somewhat obstructive in responding to Staff's data requests by not providing full information up front and thus requiring Staff to make several requests before obtaining the information it had requested. Staff, however, does not explain its own delays in making follow-up requests, nor did Staff bring the non-responsive answers to Commission's attention in an expedient manner through a discovery conference or at the status conferences held for this purpose. Therefore, the Commission finds that both parties were to blame for the delays in getting information to Staff. Because the Companies are partially to blame for this delay, the Commission finds that it was proper for the Staff to bring its specific rate case disallowances to the true-up proceeding.

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727 MEUA incorrectly argues that the total rate case expense for ER-2010-0355 and ER-2010-0356 will be $13.8 million. First, MEUA includes the $1.6 million for the previous rate cases in its beginning figure, then it adds an additional $6.1 million as testified to by Mr. Weisensee (Tr. 3634). MEUA, however, misinterprets Mr. Weisensee's testimony. The Commission interprets Mr. Weisensee as stating that the rate case expense being claimed for ER-2010-0355 and ER-2010-0356 is $6.1 million through the end of the true-up period. There will certainly be a substantial amount more rate case expense to follow; however, the evidence is unclear what additional rate case expense for these cases will be deferred to the next rate case.

728 Industrials' Initial Brief p. 66-67.

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

Certainly, given the benefits enjoyed by the shareholders, the evidence presented by Staff, and absent some sort of cost containment some disallowances are necessary. The Commission also recognizes that, unlike the period during the Regulatory Plan, KCP&L and GMO have no definitive schedule for their next rate case. Faced with similar seemingly exorbitant expenses, the KCC ordered a four-year, rather than a two-year amortization period for rate case expense. The Commission determines that an extended amortization period for rate case expense is in order; however, based on the Commission‘s experience with these companies and the amount of rate case and other expenses being deferred to a future proceeding, the Commission determines that a three-year amortization period for rate case expense is sufficient.

With regard to Staff’s proposed adjustment to remove all legal expenses of Morgan, Lewis & Bockius, Staff claims the attorneys’ rates are excessive when compared to local attorneys, the expenses are not related to the current rate case and work is duplicative of other attorneys' work. The Commission cannot determine that it is reasonable to apply the rates of Missouri law firm rates to the rates charged by attorneys practicing in other, possibly more expensive locations without better evidence. The Commission concludes the legal expenses of Morgan, Lewis & Bockius should not be eliminated as the costs were not duplicative or the evidence sufficiently competent to prove the fees were excessive.

The Commission concludes the Schiff Hardin and Pegasus witnesses each provided testimony on separate, discrete issues related to the reasonableness of the expenditures related to the construction of Iatan. As a result, there was no duplication of effort and Staff "assumed" incorrectly. Thus, the Commission rejects Staff's proposed disallowance, including a reduction to Schiff Hardin's rate as the evidence was not sufficiently competent to prove the fees were excessive.

With regard to NextSource, however, the Commission concludes Mr. Giles and Mr. Blanc's work were somewhat duplicative. In addition, the question was raised but never answered as to why KCP&L internal employees were not able to provide the services Mr. Giles provided? Based on the record, the Commission determines that the expenses with regard to NextSource as allocated by Staff between the companies shall be disallowed.

Finally, Staff has proposed the disallowance of the expenses for the services of the CCA. The CCA provided witness development and coaching services, routine tasks typically performed by retained counsel, internal or otherwise. The KCC also disallowed similar expenses as unjust and unreasonable. The Commission determines that the

CCA expense should be disallowed as duplicative of other services that were performed or should have been performed KCPL's and GMO's attorneys.

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

D. Low Income Weatherization Program

A. Should KCP&L and GMO continue to fund their low-income weatherization programs at the current levels of funding?

***B. If so, should the funds continue to be administered under current procedures or should the Commission order they be deposited into an account with the Environmental Improvement and Energy Resources Authorit*y (EIERA) to be administered by EIERA and MDNR?**

Findings of Fact – Low Income Weatherization

514. Current funding by KCP&L and GMO for low income weatherization programs annually is $573,888 and $150,000, respectively.[729]

515. KCP&L has spent approximately ninety-six percent (96%) of the budgeted funds for its existing low-income weatherization program.[730]

516. GMO has utilized a much lower percentage of the 2007 through 2010 budgeted funds for weatherization.[731]

[729] Ex. KCP&L 210, p. 143; Ex. GMO 210, p. 156.
[730] Ex. KCP&L 246, p. 4; Tr. 3606.
[731] The exact number is contained in the "Highly Confidential" Testimony of Henry E. Warren (HC), Staff Report, Revenue Requirement Cost of Service. Ex. GMO 210, p.154.

517. Staff recommended that KCP&L and GMO be required to continue to provide annual funding of $573,888 and $150,000, respectively. Staff also suggested that unspent weatherization funds should be placed into an account with EIERA.[732]

518. The Environmental Improvement and Energy Resources Authority (EIERA) is a program affiliated with MDNR. EIERA is a separate and distinct entity—a quasi-governmental agency--and is not a party to these cases. EIERA has a much broader scope and mission than just administering weatherization funds under MDNR guidelines. EIERA is "involved in numerous projects and programs including providing bond financing for environmental projects such as water and wastewater treatment facilities, energy efficiency loans and other pollution control projects. . . . EIERA has broad statutory authority that goes significantly beyond managing and disbursing federal and other weatherization funding for MDNR."[733]

519. The EIERA program has recently spent a much lower percentage of its funds than KCP&L for weatherization purposes.[734]

520. KCP&L and GMO disagree with both of Staff proposals.

521. The Customer Program Advisory Group (CPAG) includes Staff, the Office of the Public Counsel, the Missouri Department of Natural Resources, the City of Kansas City, and Praxair, Inc. The CPAG has tracked, discussed, and overseen the implementation and evaluation of KCP&L's Low-Income Weatherization Program.[735]

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[732] Ex. KCP&L 246 and Ex. GMO 247.
[733] Ex. GMO 603, p. 3.
[734] Tr. 3608.
[735] KCP&L-GMO Low Income Weatherization Program Evaluation, Opinion Dynamics Corporation, August, 2010.

522. The GMO Advisory Group (GMOAG) includes Staff, the Public Counsel, the MDNR, the City of Kansas City, and the Sedalia Industrial Energy Users Association. The GMOAG has tracked, discussed, and overseen the implementation and evaluation of GMO's Low-Income Weatherization Program.[736]

523. Prior to Staff's proposal in this proceeding, MDNR had not been approached by any party regarding the proposal to transfer funds to EIERA. To accommodate Staff's request, EIERA would have to balance resources with other projects they are involved in, and consider whether there are significant design differences between the federal weatherization programs and KCP&L's program.[737]

524. There are a number of administrative burdens for MDNR and EIERA that must be considered in order to place these funds in EIERA. No other public utility--gas or electric--has been ordered to deposit weatherization funds with EIERA; in every other case it has been the utility that requested such an arrangement. Furthermore, payment of funds could not be effectuated prior to execution of an agreement with EIERA, which in all other cases has taken the form of a Cooperation and Funding Agreement entered into voluntarily by EIERA, MDNR, the Missouri Public Service Commission and the public utility.[738]

525. In addition, KCP&L and GMO would need to commit to annual up-front funding for low-income weatherization programs for the Staff's proposed approach to be workable and the additional burdens to be justified.[739]

[736] KCP&L-GMO Low Income Weatherization Program Evaluation, Opinion Dynamics Corporation, August, 2010.
[737] Ex. KCP&L 605 and Ex. GMO 603, p. 3.
[738] Tr. 3605.
[739] Ex. KCP&L 605, p. 3.

526. The benefits of placing these funds up-front with EIERA would be to provide a definite amount of weatherization funding on an up-front basis, and provide for unspent funds, including interest, to be available to local weatherization agencies so that the funds remain available for the purpose for which they are dedicated, especially after American Recovery and Reinvestment Act funds are expended.[740]

527. No other public utility--gas or electric--has been ordered by this Commission without the utility's consent and support to deposit weatherization funds with EIERA. In every other case it has been the utility that requested such an arrangement.[741]

528. Additionally, Staff is recommending that the Companies modify their direct reimbursement payment method to the weatherization agencies from monthly to annual. To implement Staff's recommendation would be harmful to the Companies' cash flow and place an undue burden on the Companies.[742]

529. Staff further recommends that KCP&L and GMO deposit into an EIERA account any budgeted money that has not been disbursed at the end of each fiscal year and that has been specifically targeted for the Low Income Weatherization Program to be utilized by the Community Action agencies or other local agencies. Additionally, any funds that have not been spent as included in KCP&L's regulatory plan and GMO's 2007 through 2010 budget Staff recommends those funds should be put in an EIERA account.

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[740] Ex. KCP&L 605 and Ex. GMO 603, pp. 2-3.
[741] Tr. 3604-3605.
[742] Ex. KCP&L 55, p. 3; Ex. GMO 33, pp. 12-13.

530. Staff also recommends that funds expended be placed in the DSM regulatory asset account at the time it is provided to the weatherization agency or when sent to EIERA.

Conclusions of Law – Low Income Weatherization

64. The Commission has required spending by other utilities when the amount is recovered in rates as an expense.[743]

Decision – Low Income Weatherization

Two issues have been presented to the Commission for decision with regard to Low Income Weatherization programs: should the Companies be required to continue those programs and at the current level of funding; and if so, how should those funds be administered.

Staff recommended that KCP&L and GMO be required to continue to provide annual funding for low income weatherization programs in the amounts of $573,888 and $150,000, respectively.[744] Staff also suggested that unspent weatherization funds should be placed into an account with the Environmental Improvement and Energy Resources Authority (EIERA) to be administered by EIERA and the Missouri Department of Natural Resources (MDNR).[745]

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[743] *In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area,* Report and Order, File No. ER-2008-0318, (issued Jan. 27, 2009).

[744] Ex. KCP&L 210, p. 143; Ex. GMO 210, p. 156.

[745] Ex. KCP&L 246 and Ex. GMO 247.

MDNR agrees that the Companies should continue to fund their low income weatherization programs at the current funding levels, but recommends against Staff's proposed method of administration.

The Companies contend that this rate case is not the proper forum for a decision to continue the current funding levels for low income weatherization. KCP&L and GMO argue that such proposals should be first vetted with the advisory groups. The companies further argue that a Commission determination of the recovery mechanism for such programs should be made before a decision on the level of weatherization funding is made.

This rate case is the proper forum to discuss the issue of the Low Income Weatherization Program funding. The CPAG has tracked, discussed, and overseen the implementation and evaluation of KCP&L's Low-Income Weatherization Program. The GMOAG has tracked, discussed, and overseen the implementation and evaluation of GMO's Low-Income Weatherization Program.[746] However, as the name implies, these are *advisory* groups for implementing and evaluating the demand-side programs. The advisory groups cannot and should not decide the budget for low-income energy efficiency programs.

The Companies argue that the Commission cannot order spending without a cost recovery mechanism. KCP&L and GMO suggest it would be unlawful for the Commission to mandate specific funding for low income weatherization without a mechanism for the Companies to recover mandated expenditures. However, Staff's recommendations stem from programs and policies that KCP&L and GMO previously

[746] *Id.*

set in place. In addition, the Commission has required spending by other utilities when the amount is included in the case as an expense as it will be in this instance.[747]

Staff requests the Commission to order KCP&L and GMO to deposit low income weatherization funds into an account with the Environmental Improvement and Energy Resources Authority (EIERA) to be administered by EIERA and MDNR. While GMO failed to fully expend its low income weatherization funding budgeted during the regulatory plan, and recognizing there are some benefits to placing utility weatherization funds into an EIERA account, placing the funds with EIERA is not appropriate at this time. There may be significant program design differences between the federal low-income weatherization program and the companies' current low-income weatherization programs that would make program management and monitoring more difficult for MDNR. As described in MDNR witness Bickford's testimony, there are a number of administrative burdens for MDNR and EIERA that must be considered and KCP&L and GMO would need to commit to annual up-front funding for low-income weatherization programs for the Staff's proposed approach to be workable and the additional burdens to be justified. In addition, no other public utility--gas or electric--has been ordered by this Commission without the utility's consent and support to deposit weatherization funds with EIERA. In every other case it has been the utility that requested such an arrangement.

Furthermore, while the EIERA is affiliated with MDNR, EIERA is a separate and distinct entity—a quasi-governmental agency--and is not a party to these cases. EIERA is "involved in numerous projects and programs including providing bond

[747] File No. ER-2008-0318.

financing for environmental projects such as water and wastewater treatment facilities, energy efficiency loans and other pollution control projects. . . . EIERA has broad statutory authority that goes significantly beyond managing and disbursing federal and other weatherization funding for MDNR."[748] The Commission also concludes that it is unreasonable to require that KCP&L deposit funds into an EIERA account until the advisory groups have reviewed and made a recommendation on the proposal.

The Commission also concludes that it will not adopt Staff's recommendation that the Companies be required to modify their direct reimbursement payment method to the weatherization agencies from monthly to annual. The Commission concludes that this recommendation would be harmful to the Companies' cash flow and place an undue burden on the Companies.

The Commission determines that KCP&L and GMO shall: continue their respective low-income weatherization programs at their current levels of funding; continue working with local community action agencies; and evaluate transition of the low income weatherization funds to the EIERA and administration of the programs to DNR and present that evaluation to the CPAG or GMOAG for consideration. If the CPAG or GMOAG determines that MDNR administration of funds to be provided to EIERA is appropriate, a Cooperative Funding Agreement will be presented to the Commission, consistent with the method of funding other utility weatherization programs.

[748] Ex. GMO 603, p. 3.

E. Allocation of Iatan 2 Between L&P and MPS

What is the appropriate supply allocation between the L&P and MPS service territories?

Findings of Fact – Allocation of Iatan 2 Between L&P and MPS

531. This issue originates with the merger of UtiliCorp United, Inc., and St. Joseph Light & Power Company in 2000. In obtaining approval from this Commission for that merger, UtiliCorp, now named GMO, committed to not changing the rates of the former St. Joseph Light & Power Company customers due to the merger. Since that time GMO has had two rate districts, one in and about St. Joseph, Missouri—the L&P rate district—and one for the remainder of its service area—the MPS rate district. Since that merger in 2000, the premerger ownership of assets of the MPS and L&P districts have been used as the basis for assigning and allocating costs and revenues for determining rates for these two districts. [749]

532. For this case, GMO proposes allocating 41 MW of Iatan 2 to the L&P service area, and the remaining 112 MW to the MPS service area, based upon the balancing of the respective baseload capacity needs of L&P and the MPS service areas, as well as the resulting rate impacts upon its customers.[750]

533. GMO's proposed allocation of Iatan 2 results in 60% of L&P's 2011 projected peak demand to be met with base load capacity, and 61% of MPS's projected peak to be met with base load capacity. Using GMO's allocation proposal, both service

[749] Ex. GMO-210, pp. 94-95 and Appendix 5, Sch. LMM-3.
[750] Ex. GMO 33, pp. 10-12,; Ex. GMO-5, pp. 7-10; Ex. GMO 11, pp. 14-16.

areas would have nearly identical percentages of base capacity.[751] GMO's proposal also recognizes that Iatan 2 is jointly dispatched between both the L&P and MPS service areas, based upon economics rather than previous corporate history.[752]

534. The Staff is recommending that a substantially larger share of Iatan 2 be allocated to the L&P service area than what GMO has requested. Staff recommends allocating 100 MW of Iatan 2 to the L&P rate jurisdiction. Only 53 MWs would be allocated to MPS under Staff's proposal.[753] Staff's proposal would have 73% of L&P's peak met with base load capacity, and only 57% of MPS's peak would be met with base load capacity.[754]

535. The Iatan 2 Allocation issue is more akin to a rate design issue since it determines the relative amount of the rate increase that will be received by both the MPS and the L&P service areas rather than the overall revenue requirement impact of Iatan 2.[755]

536. "Until this case, with the addition of Iatan 2 at a nearly $2 billion cost, GMO's capacity costs were easily identifiable to either MPS or L&P. Although MPS and L&P generation is jointly dispatched, GMO has not needed additional capacity to serve L&P customers until now. Prior to the addition of Iatan 2, GMO's capacity addition investment and costs since the merger have all been assigned to MPS."[756]

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[751] Ex. GMO 11, pp. 15-16.
[752] Tr. 3847.
[753] Tr. 3853.
[754] Tr. 3844; Ex. GMO 11, pp. 15-16.
[755] Tr. 3821.
[756] Ex. GMO 210, p. 95.

537. When Utilicorp and St. Joseph Light & Power Company merged, St. Joseph Light & Power Company had more than enough generation resources to serve its load, including growth, for many years, and MPS needed significant additional capacity to replace its 500 MW purchased power contract that ended in May of 2005.[757]

538. Later, Aquila (now known as GMO), due to its poor financial condition, only had the opportunity to be a part owner of Iatan 2 because it had acquired St. Joseph Light & Power Company's ownership in the Iatan station in the 2000 merger.[758]

539. Because it was the MPS rate district that needed additional capacity to serve its retail customers, the costs of South Harper were assigned to MPS.[759]

540. Ownership rights of the previous stand-alone companies and the effect of the historical allocations are compelling reasons to continue the allocations based on the costs of the assets being used to serve the customers absent a full proposal to have single tariff pricing for the company.[760]

541. Staff's proposal more correctly matches the proper level of Iatan 2 costs to customers who originally supported the Iatan plant facility and who need replacement of the base load purchased power capacity that has expired. Without this amount of capacity, L&P, if it was a stand-alone utility, would not have sufficient capacity to meet the energy requirements of its customers.[761] Because MPS will also need additional

[757] Ex. GMO 210, p. 91; Ex. GMO 233, p. 4.
[758] Ex. GMO 210, p. 99; Ex. GMO 217, pp. 45-48.
[759] Ex. GMO 210, pp. 85, 95, 105-106.
[760] Ex. GMO 232, p. 8.
[761] Ex. GMO 210, p. 99; Ex. GMO 232, p. 8; Ex. GMO 233.

base load capacity, Staff has assigned the remainder of GMO's share of Iatan 2 to MPS.

542. GMO's methodology, which results in a similar mix of base/non-base generation, is not supported by the load requirements of MPS and L&P. L&P's winter heating load is of nearly the same magnitude as its summer cooling load, signifying a high saturation of electric heating whereas MPS's load showed little response to winter. As a percentage of load, L&P has more industrial load than MPS and MPS has more weather-sensitive commercial load than L&P. All of which means L&P can more efficiently use additional baseload capacity such as Iatan 2 than MPS.[762] L&P has more baseload energy needs than MPS and, therefore, should be allocated more of Iatan 2. As a result, it is appropriate it have more baseload generation in L&P's mix than MPS's.

543. Staff's allocation takes into account not only the difference in capital costs assigned to MPS and L&P, but also the impact on fuel costs. Iatan 2 is expected to be GMO's lowest cost generation unit.[763] And, it is expected to "provide inexpensive energy for at least half a century[.]"[764]

544. With the addition of Iatan 2, GMO's more expensive to run natural gas-fired units will be used less, resulting in lowered MPS fuel costs. While L&P will reap the same benefit, the beneficial impact on L&P's fuel costs will be less since power from Iatan 2 will replace low-cost energy L&P has been getting through a 100 MW purchased power agreement that ends in May of 2011. Further, for each incremental MW less than 100 MW of Iatan 2 that is allocated to L&P (the capacity of the expiring purchased

[762] Ex. GMO 233, pp. 10-11.
[763] Tim M. Rush, Tr. 3815.
[764] Tr. 3862.

power agreement), L&P's fuel costs will greatly increase because, in each hour, the low-cost Iatan 2 energy L&P would have gotten will be replaced by energy from MPS's highest operating cost unit that is running. Therefore, Staff's recommendation of allocating more MWs to L&P results in the lower fuel costs for L&P than MPS's recommended allocation.[765]

545. Counting "fuel savings of 4 to $5 million a year . . . over [a] 50-year time period, . . . [equates to] over a half a billion dollars of savings based on their [L&P's] allocation."[766] The Commission is persuaded by Staff that it is in the long-term best interest of the L&P customers to take a larger share of the allocation of Iatan 2 as an upfront cost, thereby avoiding some fuel costs and some capacity charges and giving those customers, lower-cost baseload generation for the long-term.

546. Having determined that L&P customers would benefit in the long-run from Staff's proposed allocation, the Commission still cannot, however, ignore the immediate effect on those customer's rates. It is undisputed that economic conditions are tough and that the rate impact of adding 100 MW to L&P customers "will not be easy for many of its customers."[767]

547. Staff's proposal would increase the revenue requirement for the L&P service area by approximately $20 million above GMO's request.[768] GMO requested a $22 million total increase for the L&P area after considering all of the other cost drivers in the case. Adding another $20 million to account for Staff's proposed allocation of

[765] Ex. GMO 232, p. 5.
[766] Tr. 3871-72.
[767] Ex. GMO 210, p. 95
[768] Tr. 3820.

Iatan 2, will have too much of an adverse impact upon GMO's customers that live in the St. Joseph and other L&P service areas.[769]

548. "All additions of large base load units in Missouri initially have resulted in a large increase on the utility's revenue requirement. . . . The initial inclusion of St. Joseph Light & Power Company's investment and costs in Iatan 1 in its revenue requirement caused its rates to increase by over 26%. When Union Electric Company's investment and costs in the Callaway Nuclear Plant were initially included in its revenue requirement, despite having a large customer base, it caused Union Electric Company's rates to increase by 45%. Further, when KCPL's investment and costs of the Wolf Creek Nuclear plant was first included in KCPL's revenue requirement, it caused KCPL's rates in Missouri to increase by 21.75%. Despite the initial large increase in rates when these base load units were first included in the utilities' revenue requirements, in the long-term they have resulted in lower rates for the customers of these utilities - lower rates which those customers are now enjoying."[770] Those customers who initially paid higher rates for generating facilities still being used to serve them—primarily Iatan 1—should get the benefit of the now relatively lower cost of those units to generate electricity.

549. GMO jointly dispatches its generating units to serve load in both the MPS and L&P, and has stated since it acquired St. Joseph Light & Power Company it has a long-term goal of having a uniform tariff, including uniform rates throughout its service territory.[771]

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[769] Tr. 3820.
[770] Ex. GMO 210, p. 103.
[771] Ex. GMO 210, p. 95.

550. GMO's retail rates for MPS and L&P not only differ significantly, they have differed significantly for many years. The following table shows, for residential customers, a comparison of residential rates:[772]

Residential rate (¢/kWh)	2009	2008	2007	2006	2005
KCPL- Kansas	9.07	8.43	7.43	6.92	6.88
KCPL-Missouri	8.51	8.14	7.61	6.90	6.88
MPS	**9.67**	**9.10**	**8.64**	**8.08**	**7.45**
L&P	**7.43**	**7.03**	**6.78**	**6.31**	**5.97**
Ameren Missouri	7.03	6.53	6.60	6.60	6.52
Empire	9.75	9.19	9.10	8.35	7.98
Missouri Average	7.77	7.27	5.93	6.96	6.77
USA Average	11.72	11.52	10.95	10.62	9.60

As this table shows, current MPS residential rates exceed the average of Missouri residential rates of rate regulated utilities (9.67 ¢/kWh vs. 7.77 ¢/kWh) and current L&P residential rates are below the average of Missouri residential rates of rate regulated utilities (7.43 ¢/kWh vs. 7.77 ¢/kWh).

551. GMO's proposal would have the effect of widening the gap between MPS and L&P rates;[773] Staff's proposal would not.

552. The evidence indicates that there is more than one allocation scenario for allocating Iatan 2 that would be reasonable.[774] In fact, Staff analyzed five different scenarios in the Cost of Service Report. Emphasizing different factors (such as rate impact, fuels costs, "ownership" rights, and capacity needs of each area) each of the

[772] Ex. GMO 215, p. 37.
[773] Ex. GMO 232, p. 6.
[774] Tr. 3851.

5 Scenarios may be reasonable.[775] In addition, Ms. Mantle testified during questioning from Commissioner Davis, that some other allocation may be reasonable.[776]

553. The scenarios examined by Staff are:

Scenario 1: 153 MW to L&P and 0 MW to MPS

Scenario 2: 100 MW to L&P and 53 MW to MPS

Scenario 3: 53 MW to L& P and 100 MW to MPS

Scenario 4: 41 MW to L&P and 112 MW to MPS

Scenario 5: 153 MW to MPS and 0 MW to L&P.[777]

554. The effects of each scenario on the MPS and L&P areas and the percentages of current revenues for each are as follows:[778]

MPS				
Scenario	Capital Costs	Change in Fuel Costs	Total	% of Current Revenue
1	$0	$14,115,884	$14,115,88	2.6%
2	$18,645,319	$10,532,214	$29,177,533	5.3%
3	$35,180,760	$6,079,896	$41,260,656	7.5%
4	$39,401,433	$4,764,849	$44,166,282	8.0%
5	$53,825,174	$0	$53,825,174	9.8%

775 Tr. 3851.
776 Tr. 3883-3884.
777 Ex. GMO 210, p. 98.
778 Ex. GMO 210, p. 101.

L&P					
Scenario	Capital Costs	Change in Fuel Costs	NPPD Capacity Payment	Total	% of Current Revenue
1	$53,446,83		$12,120,000	$41,326,83	31.4%
2	$34,933,38	$3,583,6	$12,120,000	$26,397,02	20.1%
3	$18,514,26	$8,035,8	$12,120,000	$14,430,11	11.0%
4	$14,322,35	$9,350,9	$12,120,000	$11,553,30	8.8%
5	$0	$14, 11	$12,120,000	$1,995,81	1.5%

555. Following the precedent of using the pre-2000 merger ownership of assets as a basis for assigning and allocating costs related to generating units for determining rates for MPS and L&P, Staff has relied on the following to shape its recommendation and the Commission also relies on these factors in making its decision: 1) It was St. Joseph Light & Power Company that had an ownership interest in the Iatan station before the construction of Iatan 2; 2) it was St. Joseph Light & Power Company that entered into a long-term purchased power contract with NPPD for 100 MW of baseload capacity that expires in May 2011, while MPS does not have a similar agreement that will expire as imminently[779]; and 3) the effects on MPS's and L&P's rates of different allocations of Iatan 2.[780]

556. Based on these considerations, the precedent of looking at the capacity needs of each district, and considering all the interests presented both long-term and short-term, the Commission finds that Scenario 3 (53 MW to L&P and 100 MW to MPS) is the allocation that is just and reasonable and in the public interest.

[779] MPS has a 75 MW purchased power agreement with NPPD, but it does not expire until 2014. Ex. GMO 11, pp. 6-7; Ex. GMO 33, p. 11, Tim M. Rush, Tr. 3880; Mantle Tr. 3867-68.

[780] Ex. GMO 233, p. 8.

557. With this allocation, both L&P and MPS will receive some of the Iatan 2 base load capacity. In addition, although a larger percentage increase in rates than proposed by GMO, L&P customers are currently paying lower rates and they will benefit long-term from the lower-cost generation far into the future.

Conclusions of Law – Allocation of Iatan 2 Between L&P and MPS

65. Based on the findings above, the Commission concludes that Staff's Scenario 3 (53 MW to L&P and 100 MW to MPS) is the allocation that is just and reasonable and in the public interest.

Decision – Allocation of Iatan 2 Between L&P and MPS

The Commission concludes that it should balance the varied interests of GMO's MPS and L&P district customers. In analyzing these interests, GMO (and the interested intervenors including the City of St. Joseph) and Staff have each presented good arguments for their allocations. The Commission has determined that allocating Iatan 2 by assigning 53 MW to the L&P district and 100 MW to the MPS district is the appropriate allocation is just and reasonable and in the public interest.

IV. Fuel Adjustment Clause

Several outstanding issues exist with regard to GMO's fuel adjustment clause ("FAC") and whether it should continue or be modified. The Commission determines these issues as set out below.

A. FAC Rebasing

Should the Company be required to rebase its fuel and purchase power expenses, net of off system sales, in excess of such amounts built into base rates?

Findings of Fact – FAC Rebasing

558. The Company did not propose to increase base rates by rebasing or resetting its Base Energy Costs, as defined in its Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets. These base costs are the core energy costs to which are applied (a) variable fuel component costs, (b) purchased power energy charges, (c) emission allowance costs, (d) adjustments for recovery period sales variations, and (e) interest on deferred electric energy costs.[781]

559. Staff has proposed to rebase the FAC Base Energy Cost. The effect of rebasing is to increase base rates equal to the normalized Based Energy Costs for fuel and purchased power costs, less off-system sales revenue in the 2009 test year, as trued-up, for both the MPS and the L&P Divisions.[782]

560. Based on the true-up information as of December 31, 2010, rebasing the FAC using Staff's recommended revenue requirements has the effect of increasing GMO's fuel adjustment clause base energy cost for MPS and L&P by 2.3% and 30.1%, respectively. But these percentages are deceptive because the FAC charge would also be lowered.[783] Customers are already paying 95% of the charges plus possible interest accruals, as part of the FAC.

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[781] *See*, GMO Tariff Sheets 124-126.1, Proposed Tariff Change Schedules.
[782] *See* Ex. GMO 210, pp. 199-201.
[783] Ex. GMO 241, pp. 8-9.

561. GMO stated that it proposed to keep the current base amounts for the MPS Division ($0.02348/KWh net system input) and the L&P Division ($0.01642/KWh net system input) in order to keep GMO's overall rate request to as low an amount as reasonable, yet still provide a fair return to the Company.[784] And, because GMO has not rebased these Base Energy Costs and has, thus, not adjusted the FAC to reflect such rebasing, GMO has agreed to forego 5% of the increase in its future fuel and purchased power expenses under the current FAC that only allows it to recover 95% of its prudently incurred costs.[785] Under GMO's proposal customers may be subjected to paying interest charges which can occur if the FAC is not rebased.[786]

562. The Commission agrees with Staff that customers in each general rate case should be assured that they receive the correct price signals through fixed rates as soon as possible.[787] GMO's proposal does not send the correct price signal to the customers.

563. The Commission will adopt Staff's recommendation to match the base energy costs in the FAC to the base energy cost in the test year total revenue requirement used for setting the general rates because doing so ensures that retail customers get the correct price signal through fixed rates for the utility's cost to serve them as soon as possible.[788] In addition, the utility's retail customers will avoid paying

[784] Ex. GMO 33, p. 3; Ex. GMO 34, p. 26.
[785] Ex. GMO 33, pp. 3-4.
[786] Ex. GMO 241.
[787] Ex. GMO 241, p. 7.
[788] Ex. GMO 241, pp. 6-9; Ex. GMO 210, pp. 199-201.

interest on fuel and purchased power costs that may be collected later through its fuel adjustment clause.[789]

564. As Staff demonstrated three examples to support rebasing that the Commission found persuasive:

> Case 1 illustrates that if the Base Energy Cost in the FAC is equal to the Base Energy Cost in the test year revenue requirement, the utility does not benefit nor is it penalized as a result of the level of actual energy costs.
>
> Case 2 illustrates that if the Base Energy Cost in the FAC is less than the Base Energy Cost in the test year revenue requirement, the utility is expected to benefit and customers are expected to be penalized regardless of the level of actual of [sic] energy costs.
>
> Case 3 illustrated that if the Base Energy Cost in the FAC is greater than the Base Energy Cost in the test year revenue requirement, the utility is expected to be penalized and customers are expected to benefit regardless of the level of actual energy costs.
>
> These three cases illustrate the importance of setting the Base Energy Cost in the FAC correctly, i.e. equal to the Base Energy Cost in the test year true-up revenue requirement.[790]

565. To accomplish the purpose of a FAC—to protect utilities and their customers from delay in recognizing changes in the costs of fuel and purchased power—the net base fuel cost in GMO's fuel adjustment clause should match with the base energy cost in the test year total revenue requirement used for setting rates in this case. GMO's Fuel Adjustment Clause should be modified to require the base energy cost in the Fuel Adjustment Clause equal the base energy cost in the test year total revenue requirement used for setting rates in the rate case.

[789] Ex. GMO 241, pp. 6-9; Ex. GMO 210, pp. 199-201.
[790] Ex. GMO 210, pp. 200-201.

Conclusions of Law – FAC Rebasing

66. No provision in Section 386.266, RSMo, requires the rebasing of Base Energy Costs in general rate cases subsequent to the proceeding that implements an FAC or other rate adjustment mechanism.

67. The Commission's fuel adjustment clause regulations found in 4 CSR 240-3.161 and 4 CSR 240-20.090 do not require a rebasing of Base Energy Costs in an FAC when a utility files a general rate case that requests that its rate adjustment mechanism be continued.

68. There is no provision in the Company's fuel adjustment clause tariffs or any of its other tariffs that requires the rebasing of its Base Energy Costs when it files a general rate case.

69. The Commission concludes, however, that the purpose of a fuel adjustment clause is to protect utilities and their customers from delay in recognizing changes in the costs of fuel and purchased power.

70. To accomplish that purpose the net base fuel cost in GMO's fuel adjustment clause should match with the base energy cost in the test year total revenue requirement used for setting rates in this case.

Decision – FAC Rebasing

Even though not required by the FAC laws to rebase, the Commission determines that it is consistent with the purpose of those laws and in the public interest to rebase the FAC Base Energy Cost. To fail to do so sends the wrong signal to the customers that the base rate they are paying includes the complete fuel costs and subjects those customers to the potential for paying interest charges. The Commission determines that the FAC shall be rebased.

B. FAC Sharing Mechanism

Should the FAC sharing mechanism be changed from 95/5 to 75/25 as proposed by Staff?

Findings of Fact – FAC Sharing Mechanism

566. GMO's FAC was established and approved in the final rate case of its predecessor Aquila, where the Commission set forth the current sharing mechanism at a 95% to 5% ratio. In that decision the Commission found that allowing Aquila to pass 95% of its prudently incurred fuel and purchased power costs, above those included in its base rates, through an FAC is appropriate. The Commission stated that with the 95% pass-through Aquila would be protected from extreme fluctuations in fuel and purchased power costs, yet retain an incentive to take all reasonable actions to keep its fuel and purchased power costs as low as possible, and still have an opportunity to earn a fair return on its investment. It concluded that a 95% pass-through would not violate Section 386.226.4(1) because it would still afford Aquila a sufficient opportunity to earn a fair return on equity.[791]

567. Since the FAC was established, Aquila/GMO have made six Cost Adjustment Factor (CAF) filings which, in total, the parties agreed resulted in the under-

[791] *See*, *In re Aquila, Inc.*, Report and Order, File No. ER-2007-0004 (May 17, 2007) at 54-55.

collection of $121 million over a 3-year period.[792] Of this amount, approximately $6 million was absorbed by the Company pursuant to the 95/5 sharing mechanism.[793]

568. In this case, Staff recommends that the sharing mechanism be modified to a 75% to 25% ratio whereby GMO would only be permitted to pass 75% of its prudently incurred fuel costs above those fuel costs included in base rates to customers. The remaining 25% would be borne by GMO itself. Intervenors AARP and Consumers Council recommend a 70/30 sharing mechanism.

569. Staff "found no evidence of imprudent decisions by the Company's management related to procurement of fuel for generation, purchased power and off-system sales."[794] At the evidentiary hearing, Staff's witness John Rogers confirmed that this was Staff's finding.[795]

570. The Staff Report and Mr. Rogers stated that prior to the inception of the Company's FAC, Aquila/GMO had under-collected $116 million during 2004-06 "for which GMO's customers were responsible for paying $0."[796] Mr. Rogers stated on cross-examination that those losses contributed to Aquila's financial problems at the time.[797]

571. GMO summarized the sharing mechanisms applicable to fuel adjustment clauses and off-system sales margin in eleven other Midwestern states.[798] Based on

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[792] Ex. GMO 210, pp. 196-97.
[793] *Id.* at 197.
[794] Ex. GMO 210, p. 193.
[795] Tr. 4476-77.
[796] Ex. GMO 241, p. 17.
[797] Tr. 4486.
[798] Ex. GMO 51.

that exhibit, other companies in the Midwest do not operate under a 95/5 sharing mechanism like GMO and other Missouri companies.[799]

572. GMO Witness Gary M. Rygh, a Managing Director of Barclays Capital Inc., testified that there would be potential adverse effects of altering the 95/5 sharing mechanism to a 75/25 ratio. He was generally familiar with fuel adjustment clauses being utilized by integrated electric utilities in the United States, most of which do not have a sharing mechanism.[800]

573. The Commission finds Mr. Rygh's background and experience relevant to this issue, and finds that his opinions are authoritative and credible.

574. Given that there is no evidence in the record that GMO has not competently managed its fuel operating expense, the investment community would take a negative view of the proposals before the Commission to change the 95/5 sharing mechanism to 75/25 or 70/30.[801]

575. Given the lack of findings of imprudence by GMO in its fuel procurement practices, there is no basis for changing the existing FAC and past-through mechanism so that GMO is not able to pass through to its customers 95% of its prudently incurred fuel and related costs.

576. Since the Company's acquisition by Great Plains Energy Inc., it has achieved an improved financial outlook with investment grade credit ratings.[802] At this time there is no basis for changing the 95/5 sharing mechanism, which would otherwise

[799] Ex. GMO 51; and Tr. 4448-51.
[800] Ex. GMO 37.
[801] Ex. GMO 37 pp. 11 and 14.
[802] Ex. GMO 210, pp. 18-19 and App. 2, Att. E (noting BBB credit rating).

bring uncertainty to the minds of investors and raise unnecessary questions for a company with a good operating record.[803]

Conclusions of Law – FAC Sharing Mechanism

71. Section 386.266, RSMo, established the policy for Missouri that cost recovery for prudently incurred fuel expenses should occur through the use of "periodic" or "interim" adjustments to rates.

Decision – FAC Sharing Mechanism

The Commission determines that there is no reason to change the current FAC sharing mechanism. GMO shall maintain the 95%/5% sharing mechanism whereby it passes 95% of its fuel costs to customers through the FAC and 5% of those costs are borne by the Company itself.

C. FAC Other Issues

Findings of Fact – FAC Other Issues

Crossroads Generating Station Factor

577. If the Commission accepts Staff's position on fuel costs in the Crossroads issue, Staff recommends the Commission authorize and require modification of GMO's fuel adjustment clause to include a new factor that would exclude an increment of GMO's fuel costs for its Crossroads generating station from Fuel and Purchased Power Adjustments (GMO FAC "FPAs"). Consistent with its position that GMO's ratepayers

[803] Ex. GMO 37, pp. 11-16.

should pay costs based on two 105 megawatt combustion turbines built in 2005 and located at the South Harper site, GMO's fuel clause should be modified so that its customers do not bear the incremental costs associated with higher gas prices and transmission costs of the Crossroads Energy Center which is located near Clarksdale, Mississippi.

578. Staff proposes the "CPG" factor be $740,071 annually; $370,035 for each six-month accumulation period. Staff proposes this factor consistent with its position fuel costs for Crossroads are higher than they would be had GMO built two additional 105MW combustion turbines at South Harper in 2005.[804]

579. The Commission has not accepted Staff's position relating to the two additional turbines at South Harper.

Forecasted Retail Net System Input Definition

580. Staff recommends the Commission authorize and require modification of GMO's FAC so that the factor RNSI (forecasted retail net system input) in GMO's FAC use be redefined to clarify that it is based on net system input *at the generator*.[805]

581. This change should have no substantive effect.

582. GMO does not oppose this clarification.

583. The FAC should be clarified as proposed.

[804] Ex. GMO 211, p. 34, Sch. JAR-2-14; Ex. GMO 241, Sch. JAR-2-14 Revised.
[805] Ex. GMO 211, p. 33, Sch. JAR-2-16.

Only Sales to Missouri Municipalities Excluded From OSS Revenues

584. Staff recommends the Commission authorize and require modification of GMO's FAC to clarify that only sales to Missouri municipalities are excluded from off-system sales revenues (GMO FAC factor "OSSR").[806]

585. This change should have no substantive effect.

586. GMO does not oppose this clarification.

587. The FAC should be clarified as proposed.

Additional Clarifications

588. Staff recommends the Commission authorize and require certain other modifications to GMO's FAC tariff sheets to clarify and improve them as shown in the example tariff sheets attached to Staff's Rate Design and Class Cost-of-Service Report, as revised in schedules attached to the surrebuttal testimony of Staff witness John A. Rogers.[807]

589. GMO agrees to these modifications to the extent that Staff's proposed changes match changes proposed by GMO witness Tim Rush.[808]

590. The FAC should be clarified as proposed.

[806] Ex. GMO 211, p. 34, Sch. JAR-2-15; Ex. GMO 241, Sch. JAR-2-15 Revised.
[807] Ex. GMO 211, Schs. JAR-1 and JAR-2; Ex. GMO 241, Schs. JAR-1-10 Revised, JAR-2-14 Revised and JAR-2-15 Revised
[808] Ex. GMO 2, Sch. TMR2010-3.

Transmission Expenses

591. The Company had requested in its initial filing that all transmission costs be included in the FAC tariff or, in the alternative, that a transmission tracker be established to ensure the appropriate recovery of transmission costs.

592. Staff opposes GMO's proposed modification to include transmission expenses and, in addition, proposes GMO's fuel adjustment clause be modified to remove from the definition of Purchased Power Cost in the clause two FERC accounts—FERC account numbers 565 and 575.[809]

593. The issue of a transmission tracker was settled in the Non-Unanimous Stipulation and Agreement as to Miscellaneous Issues, filed on February 3, 2011 ("Miscellaneous Issues Stipulation"). In the section related to Transmission Expense and Revenue Tracker, the stipulation provides: "The Signatories agree that a tracker for changes in certain transmission-related expenses should not be implemented in this case."[810]

594. The Company opposes the Staff's proposed exclusion of expenses currently included in the FAC tariffs, including the transmission expenses that are now in the FAC.

595. The only transmission costs currently included in the FAC are those costs attributable to off-system sales.[811] These costs are essential to determine overall off-system sales cost and margins. The transmission costs associated with off-system sales are variable costs and are only incurred when off-system sales are made.

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[809] Ex. GMO 211, Sch. JAR-2-15; Ex. GMO 241, Sch. JAR-2-15 Revised.
[810] *See*, Miscellaneous Issues Stipulation at 8.
[811] Ex. GMO 32, p. 19.

596. The FACs utilized by both The Empire District Electric Company and Ameren-Missouri contain similar transmission cost recovery language as does GMO's proposed tariff.

597. GMO's proposal to include all transmission expenses in its fuel adjustment clause is based on its faulty interpretation that "transportation" costs as used in 4 CSR 240-20.090(1)(B) and therefore, Section 386.266.1, RSMo. Supp. 2010, includes transmission costs.[812] GMO witness Tim Rush even draws a distinction between "transportation" and "transmission" costs in his direct testimony when he says, "The increasing prices for natural gas, coal, coal *transportation* and *transmission* costs are not costs that can be controlled by the Company, nor are they costs that can be absorbed by reducing other costs."[813]

598. There was no evidence that transmission expenses vary in a direct relationship with fuel or purchased power.

599. GMO's original proposal to include all transmission costs in its FAC tariff is rejected.

600. Staff's position that the transmission costs necessary to make off-system sales should somehow be excluded from the FAC is rejected. However, the Commission has previously found in this order that it is not just and reasonable for customers to pay for the transmission expenses from the Crossroads facility. Because no transmission expenses from the Crossroads facility will be included in rates, those expenses shall also not be allowed through the FAC .

[812] Ex. GMO 35, p. 2.
[813] Ex. GMO 32, p. 6. (Emphasis added.)

Conclusions of Law – FAC Other Issues

72. Both Empire[814] and Ameren[815] have tariffs which include the same transmission costs that Staff is now recommending be removed from the GMO FAC tariffs.

73. Section 386.266.1 states:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including ***transportation***. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.[816]

74. The statutes at Section 386.520.1 make a distinction between transmission and transportation. That subsection states in part:

> . . . In case the order or decision of the commission is stayed or suspended, the order or judgment of the court shall not become effective until a suspending bond shall first have been executed and filed with, and approved by, the circuit court, payable to the state of Missouri, and sufficient in amount and security to secure the prompt payment, by the party petitioning for the review, of all damages caused by the delay in the enforcement of the order or decision of the commission, and of all moneys which any person or corporation may be compelled to pay, pending the review proceedings, for ***transportation***, ***transmission***, product, commodity or service in excess of the charges fixed by the order or decision of the commission, in case such order or decision is sustained.[817]

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[814] The Empire District Electric Company, P.S.C. Mo. No. 5 Sec. 4, 7th Revised Sheet No. 17.

[815] Ameren-Missouri, MO.P.S.C. SCHEDULE NO. 5, 1st Revised SHEET NO. 98.1. (Under the Ameren tariff, the reference to transmission costs is found in the description of Account 565, which is the FERC account containing transmission costs.)

[816] Emphasis added.

[817] Section 386.520.1, RSMo. 2000. (Emphasis added.)

75. Commission rule 4 CSR 240-20.090(1)(B) states in part:

> (B) Fuel and purchased power costs means prudently incurred and used fuel and purchased power costs, ***including transportation costs***. Prudently incurred costs do not include any increased costs resulting from negligent or wrongful acts or omissions by the utility. If not inconsistent with a commission approved incentive plan, fuel and purchased power costs also include prudently incurred actual costs of net cash payments or receipts associated with hedging instruments tied to specific volumes of fuel and associated ***transportation*** costs.
>
> 1. If off-system sales revenues are not reflected in the rate adjustment mechanism (RAM), fuel and purchased power costs only reflect the prudently incurred fuel and purchased power costs necessary to serve the electric utility's Missouri retail customers.
>
> 2. If off-system sales revenues are reflected in the RAM, fuel and purchased power costs reflect both:
>
> A. The prudently incurred fuel and purchased power costs necessary to serve the electric utility's Missouri retail customers; and
>
> B. The prudently incurred fuel and purchased power costs associated with the electric utility's off-system sales;
>
> (C) Fuel adjustment clause (FAC) means a mechanism established in a general rate proceeding that allows periodic rate adjustments, outside a general rate proceeding, to reflect increases and decreases in an electric utility's prudently incurred fuel and purchased power costs. *The FAC may or may not include off-system sales revenues and associated costs.* The commission shall determine whether or not to reflect off-system sales revenues *and associated costs* in a FAC in the general rate proceeding that establishes, continues or modifies the FAC;[818]

76. The Commission concludes that all transmission costs should not be included in GMO's adjustment clause because they are not included in section 386.266, RSMo. Supp. 2010, as a type of cost to be recovered through a fuel adjustment clause, they are inconsistent with the definitions of fuel and purchased power cost in 4 CSR 240-20.090(1)(B), and elsewhere, and they do not vary in a direct relationship with fuel or purchased power. With regard to the transmission costs specifically related to OSS,

[818] Emphasis added.

however, those costs shall be allowed to the extent that they do not include transmission costs from the Crossroads facility.

Decision – FAC Other Issues

The Commission did not find in favor of Staff's prudence disallowance and imputed costs for two additional turbines at South Harper. Therefore, the Commission will not add the Crossroads Generating Station Factor in the FAC.

GMO's FAC shall be modified so that the factor RNSI (forecasted retail net system input) is redefined to clarify that it is based on net system input *at the generator* as set out in Exhibit GMO 211, Staff Rate Design and Class Cost-of-Service Report, at page 33, Schedule JAR-2-16.

GMO's FAC shall be modified to clarify that only sales to Missouri municipalities are excluded from off-system sales revenues (GMO FAC factor "OSSR") as set out in Exhibit GMO 241, Surrebuttal Testimony of John Rogers, Schedule JAR-2-15 Revised.

GMO's FAC tariff sheets shall be modified to clarify and improve them as shown in the example tariff sheets attached to Staff's Rate Design and Class Cost-of-Service Report, as revised in schedules attached to the Surrebuttal Testimony of John A. Rogers to the extent that Staff's proposed changes match changes proposed by GMO in the Direct Testimony of Tim M. Rush.

The Commission determines that transmission costs for OSS are appropriately included in the FAC under the Commission's rule 4 CSR 20.090(1)(B). All other transmission costs are not appropriate and shall not be included. In addition, because the Commission has determined that transmission costs from the Crossroads facility shall not be borne by the ratepayers, those costs shall also be excluded from the FAC mechanism. Staff's position that the transmission costs necessary to make off-system sales should be excluded is rejected.

THE COMMISSION ORDERS THAT:

1. The seven Nonunanimous Stipulations and Agreements referenced in this Report and Order are approved, and the signatories thereto are ordered to comply with those Nonunanimous Stipulations and Agreements. The agreements and dates filed are:

Non Unanimous Stipulation and Agreement Regarding Depreciation and Accumulated Additional Amortization	February 2, 2011
Non-unanimous Stipulation and Agreement as to Outdoor Lighting Issues	February 3, 2011
Non-unanimous Stipulation and Agreement as to Miscellaneous Issues	February 3, 2011
Non-unanimous Stipulation and Agreement as to Class Cost of Service / Rate Design	February 17, 2011
Non-unanimous Stipulation and Agreement as to MGE Rate Design Issue	February 17, 2011
Non-unanimous Stipulation and Agreement Regarding Pensions and Other Post-employment Benefits	March 23, 2011
Non-unanimous Stipulation and Agreement as to Iatan Common Costs	March 23, 2011

2. The proposed tariff sheets filed by KCP&L Greater Missouri Operations Company on June 4, 2010, Tariff No. JE-2010-0693, are rejected.

3. KCP&L Greater Missouri Operations Company shall file tariffs that comport with this Report and Order no later than May 12, 2011.

4. The Staff of the Commission shall file a recommendation regarding the tariffs ordered in paragraph [3] no later than May 16, 2011. Any party that wishes to object to the tariffs ordered in paragraph [3] shall do so no later than May 16, 2011.

5. Staff's March 18, 2011 objection to Kansas City Power & Light's late-filed exhibit is overruled, and the exhibit is admitted into evidence as KCP&L Exhibit 127.

6. The late-filed exhibit filed on March 2, 2011 by Kansas City Power & Light is admitted into evidence as KCP&L Exhibit 128.

7. Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company's Motion to Late-File Exhibit filed on March 3, 2011 is granted; Exhibit GMO 49 is admitted into evidence.

8. The Staff of the Missouri Public Service Commission's amended motion to file late Exhibit GMO 265 filed on March 29, 2011 is granted; Exhibit GMO 265 is admitted into evidence.

9. All pending motions and other requests for relief not granted are denied.

10. This Report and Order shall become effective on May 14, 2011.

BY THE COMMISSION

Steven C. Reed
Secretary

(S E A L)

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

Dated at Jefferson City, Missouri,
on this 4th day of May, 2011.