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	Additional Amortizations
	Hawthorn 5 Settlements
Witness:	*Cary G. Featherstone*
Sponsoring Party:	*MoPSC Staff*
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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTAL TESTIMONY

OF

CARY G. FEATHERSTONE

Great Plains Energy, Incorporated
KANSAS CITY POWER & LIGHT COMPANY

FILE NO. ER-2010-0355

Jefferson City, Missouri
January 2011

TABLE OF CONTENTS OF

SURREBUTTAL TESTIMONY OF

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Q. Please state your name and business address.

A. Cary G. Featherstone, Fletcher Daniels State Office Building, 615 East 13th Street, Kansas City, Missouri.

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

A. I am a Regulatory Auditor with the Missouri Public Service Commission (Commission).

Q. Are you the same Cary G. Featherstone who filed direct testimony in this proceeding?

A. Yes, I am. I, with Curt Wells, filed direct testimony in this case on November 10, 2010 sponsoring Staff's cost of service report (COS Report) for Kansas City Power & Light Company's (KCPL or Company) rate case filed on June 4, 2010. I also filed rebuttal testimony in this case on December 8, 2010.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to address the rebuttal testimony filed by KCPL witness Larry W. Loos, a Black & Veatch consultant hired by KCPL, relating to the Company's proposal for jurisdictional allocations. Specifically, Mr. Loos proposes to allocate the profit from KCPL's off-system sales (off-system sales margins) in a uniquely different manner from how the parties and this Commission in past cases have assigned off-system margins to the different jurisdictions where KCPL operates its electrical system—Missouri and Kansas.

I am also providing testimony on the Experimental Alternative Regulatory Plan Additional Amortizations—the accumulated additional amortizations. This is the last rate case which deals with these amortizations under the KCPL Experimental Alternative Regulatory Plan (Regulatory Plan) approved by the Commission on July 28, 2005 in Case No. EO-2005-0329.

I am also providing testimony on the topic of the Hawthorn 5 settlements. This matter relates to two settlements KCPL received for the failure of critical equipment at its Hawthorn 5 Generating Station.

EXECUTIVE SUMMARY

Q. Would you please summarize your surrebuttal testimony?

A. Staff continues to believe that the Commission should reject KCPL's proposed method of allocating off-system sales margin using a demand allocator. The result of Mr. Loos' allocation method is to allocate a disproportionate share of off-system sales margin to KCPL's other state jurisdiction—Kansas, using what is called the demand allocator. This proposal allocates a smaller amount of off-system sales margin to Missouri resulting in a higher revenue requirement to Missouri retail customers. KCPL has implemented the results of Mr. Loos' recommendations in its case for off-system sales.

Staff has used a method to allocate off-system sales which has been used for many years for KCPL rate cases and other utilities regulated by this Commission. This method uses the energy allocation to allocate the revenues, expenses and ultimately the net contribution known as the off-system sales margin to the various jurisdictions in which KCPL provides electric services—primarily the two state jurisdictions of Kansas and Missouri. The energy allocation method is superior to the use of the KCPL demand allocation method because the revenues, expenses and net margin of off-system sales are considered variable in nature. The costs to produce or purchase electricity to make these off-system sales are treated as a variable expense and, hence the energy factor is used to allocate those costs in all aspects of the cost of service regardless of serving the native load customers or serving the off-system sales market.

Staff modified its position regarding the Experimental Alternative Regulatory Plan Additional Amortizations from the position filed in its direct filing. This modification was made after the discussions with the other parties including the Company at the prehearing conference and the review of the parties' rebuttal testimony. Initially, the accumulated additional amortizations were treated as an off-set to rate base with recovery of those amortizations from the reduction of cost of removal component of depreciation expense. The accumulated additional amortizations are still being proposed to be treated as an off-set to rate base but recovery over time will be leaving those accumulated amounts in depreciation reserve assigned to Iatan 2, the newly completed coal-fired unit located in Weston, Missouri. This approach reduces rate base which reduces the return that customers are responsible for this power plant over time.

The last area this testimony addresses are two settlements received by KCPL from contractors supplying equipment and services for its Hawthorn 5 Generating Station (Hawthorn 5). This generating station had equipment issues so serve it received settlements from the contractors to remove future liability. KCPL has retained these settlements even though customers have paid for additional costs to operate and maintain Hawthorn 5 in the past, present and in the future. Staff has included the settlements in its case to portion of some of the operating and maintenance costs associated with this generating facility.

JURISDICTION ALLOCATIONS

Q. Mr. Loos states at page 1 of his rebuttal testimony, it is not entirely clear to him from the Staff Cost of Service Report what recommendation Staff is making regarding the jurisdictional allocation of off-system sales margin and that "Staff does not make a definitive recommendation regarding the allocation of off-system sales revenues, much less off-system sales margin." What is Staff's recommendation for allocating off-system sales margins among the jurisdictions?

A. Staff used the energy allocation factor to allocate off-system sales to the Missouri retail jurisdiction. That allocation factor, which Staff used in its revenue requirement model is 56.94%, and was applied to the off-system sales margins included in the income statement of the Accounting Schedules Staff filed in this case with its Cost of Service Report on November 10, 2010. A full discussion of Staff's energy allocation factor and how Staff applied it in this case is found in the Staff's Cost of Service Report at pages 182 through 187.

Q. Would you summarize KCPL's position regarding the allocation of off-system sales to the Missouri retail jurisdiction?

A. Yes. KCPL proposes to allocate off-system sales margins to the Missouri retail jurisdiction with a demand allocation factor. KCPL developed this demand factor by using the four coincident peaks of the summer months in much the same way Staff developed its demand allocation factor, which it uses to allocate fixed costs, such as generation units and transmission lines, to the jurisdictions. Staff describes how it developed its demand allocation factor on pages 181-2 of the Staff's Cost of Service Report.

Mr. Loos suggests that off-system sales margins represent a contribution to fixed costs and therefore, it is appropriate to use a demand allocator to allocate off-system sales margins to the jurisdictions. Off-system sales margins are nothing but the net of off-system sales revenues and the costs incurred to make the sales that generate those revenues. Both off-system sales revenues and the costs incurred to get those off-system sales revenues are variable. The costs are predominately the cost of the fuel burned to generate the electricity (energy) that is sold and the revenues are dependent on the amount of the electricity (energy) sold. Netting off-system sales with the costs to make those sales—off-system sales margin—does not transform these variable costs and revenues into something that is fixed in nature, nor does Mr. Loos explain in either his direct or rebuttal testimonies why he views off-system sales margins to represent "a contribution to fixed costs." Because both off-system sales revenues and the costs incurred to make the sales that generate those revenues are dependent on the electricity (energy) sold, it is inappropriate to use a demand allocator, and it is appropriate to use an energy allocator to allocate off-system sales margins to the Missouri retail jurisdiction, as it would be to allocate off-system sales margins to the Kansas retail jurisdiction.

Q. Does Staff have any other support for why the demand allocation factor is inappropriate to use for allocating off-system sales margins to the Missouri retail jurisdiction, but the energy factor is?

A. In the past, and currently with Staff proposal in this case, off-system sales were considered variable to the utility operations in that the sales and the related costs—both fuel and purchased power vary with the energy sold. Just as both KCPL and Staff allocate fuel and purchased power costs for native load customers using the energy allocator because they vary with the energy (electricity) those customers use, the related costs for making off-system sales also vary with the energy (electricity) sold off system. The residual off-system sales margins are variable as well so it is appropriate to use the energy factor—not the demand factor.

Q. On page 2 of his surrebuttal testimony Mr. Loos states "off-system sales margin represents the contribution to fixed costs provided by off-system sales." Does Staff agree this statement?

A. No. Off-system sales are made when KCPL has either excess generating capacity or can purchase power after all system requirements are met. Off-system sales are made on a non-firm basis as the power market needs energy. KCPL has designed its electric system—both its generating and transmission system to meet its native load customers' demand for electricity. When opportunities arise to make non-firm sale transactions, KCPL, like other electric utilities, will sell energy from its idle capacity into the open power market. In the rate setting process, off-system sales are used to off-set what would otherwise be the utility's overall revenue requirements of the case. KCPL, on the other hand, takes the position, off-system sales represent a contribution to the Company's fixed costs.

Regardless, while I do not believe off-system sales is a contribution to the fixed costs of the Company or any particular component of its operations, it is certainly more reasonable to conclude that off-system sales are more closely tied to a utility's variable costs than to its fixed costs. As such, off-system sales can be thought of as a reduction to the fuel expense. Certainly, that is the way off-system sales are treated in GMO's and other utilities' fuel clauses.

Q. Mr. Loos states at page 2 of his rebuttal testimony that "off-system sales margin is equal to off-system sales revenues less the incremental (out-of-pocket) costs incurred in generating (and/or purchasing) the energy sold off-system." Do you agree with him?

A. Yes. That is how off-system sales margin is defined for purposes of ratemaking where the margins are used to offset what would otherwise be the utility's revenue requirement. By this definition of off-system sales they are defined to be variable in nature. I agree with Mr. Loos that off-system sales margins are determined by the revenues of the off system sales less the incremental costs incurred to realize those sales, costs which are variable. These variable costs are costs such as the energy costs relating to off-system sales, and these costs should be allocated using a allocation basis that is variable in nature—the energy allocation factor.

Q. Does KCPL allocate off-system sales using an energy allocation factor?

A. Yes. KCPL makes capacity sales when it has excess capacity available on a longer-term basis. Capacity sales are made to provide electricity over a period of time under a contract agreement. Capacity sales pricing has two components—one to recover capacity costs (fixed) costs and a second to recover the variable fuel costs. The demand charge is to recover capacity costs—the fixed costs such as the plant equipment. Both KCPL and Staff use the demand factor to allocate these capacity costs.

The energy costs—the second component of the capacity sales to recover the variable fuel costs—are to cover the incremental costs (the variable costs) of the sales transaction. Both KCPL and Staff use the energy factor to allocate the energy portion of the capacity sales costs. Since the 2006 rate case until and including this current case, KCPL has not used a demand allocation factor to allocate the energy portion of the capacity sales. KCPL's proposed use of the demand allocation factor to allocate non-firm off-system sales is inconsistent with the way it allocates the energy component of capacity sales.

Q. Mr. Loos states at page 2 of his rebuttal testimony that he makes a distinction of allocating off-system sales margin and off-system sales but says “both Staff and Mr. Meyer would ignore this distinction.” Does Staff make a distinction between off-system sales margin and off-system sales?

A. Yes, typically we do. However, since KCPL begin using a model to identify the level of off-system sales margins only to include in its rate cases, this distinction has not existed in KCPL’s rate cases, and has not existed since the 2006 rate case when this model was first used. In every rate case since 2006 the Company only identifies the level off-system margins generated by its model, which then is included in revenue requirement calculation. I certainly agree with Mr. Loos that off-system sales is different than off-system sales margins—one relates strictly to the level of revenues (off-system sales) and the margin is off-system sales less off-system sales costs (fuel and purchased power costs) to produce those sales. When determining the off-system sales margin it is important to use the same allocation approach. That is, since the costs – both fuel and purchased power—are variable costs to the production of electricity, regardless if the energy is for native load customers or for off-system sales made in the bulk power markets, then those costs are allocated using the energy allocation factor, a variable cost factor, not the demand factor, a fixed cost factor. The revenues for off-system sales would be allocated based on energy usage as well. Thus, the resulting off-system sales margin (sales less costs) would also be allocated based on energy usage.

It is interesting to note that even Mr. Loos acknowledges at page 2 (line 14) of his rebuttal testimony that off-system sales have variable costs, even though he believes it “is not really a material issue.” He restates again at page 3 of his rebuttal (line 10) “the costs associated with generating energy sold off-system are included in total variable costs.” The costs Mr. Loos is referring when he identifies "the costs associated with generating energy sold…" are the fuel and purchased power costs.

Q. What does Mr. Loos define as the "real issue" in this case regarding the jurisdictional allocation of off-system sales margins?

A. At page 2 of his rebuttal testimony he states that he believes "the real issue is the allocation of the revenues in excess of the out-of-pocket cost of making off-system sales (off-system sales margin)." This is where the KCPL recommendation of allocating off-system sales using the demand allocation factor makes no practical sense. If one recognizes that fuel and purchased power costs are variable costs--which they are—then you simply cannot logically allocate the off-system sales margin on any other basis than using the energy allocation factor.

Q. Why are fuel and purchased power considered to be variable costs?

A. Both of these costs are identified with output of generation. For every megawatt hour of electricity generated an amount of fuel is required measured on a mmbtu basis. Of all costs necessary to operate an electric utility, fuel costs are the most variable in nature. As such, the only practical way of properly allocating fuel costs to state jurisdictions is by using an energy allocation factor. Since fuel and purchased power costs are the only costs considered for off-system sales margin-- the residual left from the off-system sales revenues less off-system sales expenses—then it only makes sense to allocate these margins by using the variable allocator—the energy allocation factor.

However, Mr. Loos touches on in his rebuttal testimony at page 3, the problem KCPL's proposal to use a demand allocation factor for off-system sales margins presents. Mr. Loos states Mr. Meyer, Staff and KCPL "seem to agree to allocate variable costs (power supply) in proportion to energy sales. While we may not agree on the level of variable costs associated with off-system sales, the implication of any difference is relatively minor. The costs associated with generating energy sold off-system are included in total variable costs." But since these costs to generate are variable then they should be allocated based on energy, just as the fuel and purchased power costs to supply native load are allocated based on energy.

Q. At page 3 of Mr. Loos rebuttal testimony, he states his method to allocate off-system sales is "more precise." Do you have a comment on this?

A. It is unclear why Mr. Loos believes his method to allocate off-system sales is "more precise." All KCPL does with Mr. Loos' demand allocation factor is to apply it to off-system sales margins. The Company has not allocated off-system sales revenues or costs (fuel and purchased power) in this case—only the margins. The out-of-pocket costs for off-system sales Mr. Loos addresses in his rebuttal testimony at page 3, line 16, are the fuel and purchased power costs—there are not any other costs assigned to off-system sales. So his "more precise method" is nothing more than recognizing that the variable fuel and purchased power costs for off-system sales are allocated using the energy allocation factor and then KPCL proposes the revenues that exceed the variable fuel and purchased power costs be allocated using the 4 CP demand allocation factor. This is not only an imprecise method—it is a wrong method.

Since the only costs identified with off-system sales revenues are fuel and purchased power costs which Mr. Loos agrees are variable (page 3, line 10 of his rebuttal testimony), then the only proper way to allocate off-system sales margins is with an energy allocation factor.

Q. Has the Commission addressed the use of the energy allocation factor for off-system sales margins in the past?

A. Yes. In KCPL's 2006 rate case the Commission explained the reason for using the energy factor for off-system sales margins at page 39 of its Report and Order:

> The only costs assigned to non-firm off-system sales is the fuel and purchased power costs - the variable costs - hence the appropriateness of using the energy allocator. This is consistent with the way KCPL itself allocates the costs relating to the energy portion of firm capacity contracts – using the energy allocator. **The reason is simple – the energy allocator is used to allocate variable costs of fuel and purchased power costs relating to retail sales. Using the same rationale, the energy allocator is equally appropriate to use as the allocation factor for both energy of firm (as KCPL does) and non-firm off-system sales.** The demand based unused energy allocator should not be used to allocate off-system sales – either energy from firm capacity sale contracts or non-firm off-system sales. Because plant is not dedicated to support non-firm off-system sales, there is no associated demand charge.
>
> [Commission Order in Case No. ER-2006-0314, page 39; emphasis added]

Q. How long have Kansas and Missouri used different methodologies for determining jurisdictional allocation factors?

A. Since the 1970s that I am aware of.

Q. Has the Missouri Commission ever attempted to address the differences in the allocation methods between it and the Kansas Corporation Commission?

A. Yes. In the 1980s the Commission ordered Staff to meet with members of the Kansas Staff. The Missouri Staff contacted the Kansas Staff about a meeting to discuss jurisdictional allocations. A meeting was held but no consensus could be reached. Kansas has continued to use an allocation method which is not appropriate to Missouri, or even appropriate to Kansas from the Company's perspective.

Q. What is the method used by the Kansas Corporation Commission?

A. Kansas uses the 12 CP method to develop its demand factor. Mr. Loos has testified that he does not support the use of the 12 CP method for either Kansas or Missouri.

In fact, Mr. Loos filed very similar testimony in Kansas to what he filed in Missouri and testified that he was not in support of using the 12 CP method and would file against that method in the future. It was only because of agreements in Kansas that KCPL entered into, which required the use of the 12 CP method there.

Q. Should this Commission use the same allocation methodology the Kansas Corporation Commission used in order to eliminate this difference between the two jurisdictions?

A. No. Staff views the problem with the jurisdictional allocation factors to rest squarely with Kansas. As indicated above and in my rebuttal testimony, KCPL does not believe in the use of the 12 CP methodology and now supports the 4 CP method used in Missouri and ordered by the Commission as recently as the 2006 KCPL rate case. In fact, the Company used the 4 CP method in this case to develop the demand allocation factor it uses to allocate off-system sales margins.

Q. Has the Company consistently used this method to allocate off-system sales margins?

A. No. While it did in the last rate case—the 2009 rate case—it proposed to use what it referred to as the unused energy factor in its 2006 rate case. I presented a table in my rebuttal testimony (page 27) that identifies the various positions KCPL has taken in Missouri over the years regarding jurisdictional allocations.

It should be noted that the table contains an error relating to KCPL's position in its Case No. ER-2009-0089 rate case. KCPL proposed a 4 CP method to develop the demand allocation factor, just as it is doing in this case. I inadvertently indicated in this table that the Company proposed a 12 CP method instead of a 4 CP method in the 2009 rate case.

Q. Why are the differences in the demand allocation factors used in Kansas and Missouri important in the discussion of off-system sales margins?

A. The whole reason for allocation issues that have existed and continue to exist today between KCPL and Staff is the impact on the Company's ability to recover all of its reasonable costs. This happens because of the two different methods used. KCPL has attempted to address this with Missouri for years. It has not done so in Kansas until recently, not until its last Kansas rate case. The Missouri Staff believes it has been using the combination of the correct allocation methodology based on the operations of the Company. That is, using the 4 CP method to develop the demand allocation factor and using the energy allocation factor to allocate off-system sales. On the other hand, because of agreements it made in Kansas, KCPL is required to use a 12 CP method for its demand factor and it proposed its demand factor be used allocate off-system sales margins in that state. The Kansas Commission started to use the unused energy allocation factor in 2006 when it was first presented by KCPL. The Kansas Commission has used it ever since—now to the displeasure of KCPL.

Q. What methods for developing jurisdictional allocation factors should be used for KCPL?

A. Considering the peak demands of the Company and the load factor identified with each state (addressed in my rebuttal testimony at page 34), the 4 CP method is the correct method for developing the demand allocation factor. A good part of the issue in Missouri with the Company has been its acknowledgment to use the 4 CP method instead of the 12 CP method it has proposed in the past. However, the concerns of KCPL regarding its inability to recover all of its costs between the two jurisdictions, drives the need for it to pursue improper approach regarding off-system sales using the demand allocation factor.

KCPL should use the 4 CP method to develop the demand allocation factor and apply it consistently to all production and transmission plant investments and costs. KCPL should use the demand factor to the demand component and the energy factor for all energy portions of capacity sales. KCPL should also use the energy factor for all non-firm off-system sales. The above should be used consistently in all jurisdictions where KCPL operates.

REGULATORY PLAN ADDITIONAL AMORTIZATIONS

Q. Has Staff revised its recommendation concerning the rate treatment for the Experimental Alternative Regulatory Plan Additional Amortizations?

A. Yes. Through review of other parties' positions and discussions with the other parties, primarily during the prehearing conference, Staff has modified its recommended rate treatment concerning the accumulated additional amortizations[1]. Instead of using the accumulated additional amortizations to fund cost of removal expenses, Staff's revised recommendation places the accumulated additional amortizations in the Iatan 2 depreciation reserve. Staff witness Arthur W. Rice addresses the revised depreciation rates which include an allowance for cost of removal in his revised depreciation study attached to his surrebuttal testimony.

Q. Why has Staff revised its recommendation?

A. Staff reviewed the testimony of all the witnesses who address the rate treatment of the Regulatory Amortizations, and specifically the rebuttal testimony (pages 24 to 28) of KCPL witness John P. Weisensee. The Office of the Public Counsel (Public Counsel) and the Midwest Energy Users Association, Praxair, Inc., Ag Processing, an cooperative, and the

[1] For purposes of this testimony, Staff refers to the revenue stream associated with additional amortizations, as "additional amortizations." Staff refers to the capital accumulated from the revenue stream as "accumulated additional amortizations." Staff refers to the sum of the revenue streams from prior rate cases as cumulative additional amortizations."

Sedalia Industrial Energy Users Association, (the "Industrial Intervenors") through the testimony offered by Mr. Greg Meyer, also provided proposals on the rate treatment of the Regulatory Amortizations.

On the basis of the various proposals presented in the direct testimonies of the parties and the rebuttal testimony of KCPL, as well as certain Stipulations and Agreements discussed more fully in Mr. Rice's testimony; Staff considers it most appropriate to revise its position so that the Regulatory Amortizations would be specifically identified over the life of Iatan 2.

Q. What is the difference between the position presented by Staff in its direct case and the revised position?

A. The major difference is that Staff is no longer using the accumulated additional amortizations for the cost of removal expense of the depreciation rates. This was identified in the Staff Cost of Service Report under the section VIII Depreciation – D. Staff's Analysis—Staff Case A at page 160 sponsored by Mr. Rice.

Under the revised recommendation, the accumulated additional amortizations continue to be used as an offset to rate base just as it was under the initial proposal but Staff has included a cost of removal component (net salvage) in the depreciation rates. This is discussed in detail in Mr. Rice's surrebuttal testimony. Under the revised proposal the accumulated additional amortizations are now being treated as an increase to the Iatan 2 accumulated depreciation reserve.

Q. Has the Commission provided guidance on how the accumulated additional amortizations should be treated?

A. Yes. The Commission approved a stipulation reached between certain parties in Case No. ER-2006-0314. The document was entitled "The NONUNAMIMOUS

STIPULATION AND AGREEMENT REGARDING REGULATORY PLAN ADDITIONAL AMORTIZATIONS" (the "2006 Stipulation") and was attached as Appendix B of Case No. ER-2006-0314 *Report and Order* issued December 21, 2006 ("*Order*"). The 2006 Stipulation identifies parameters on the proper treatment of the Regulatory Amortizations.

The Commission states at page 56 of its 2006 Order regarding the rate treatment of the Regulatory Amortizations:

> In the stipulation labeled Appendix B, the signatories agreed pursuant to and in compliance with the provisions of the Stipulation and Agreement that the Commission approved in Case No. EO-2005-0329, any Regulatory Plan additional amortization that is provided to KCPL pursuant to that Stipulation and Agreement shall be used as a reduction in rate base for the longer of (a) at least ten (10) years following the effective date of the July 28,2005 Report And Order in Case No. EO-2005-0329 or (b) **until the investment in plant in service** accounts to which the Regulatory Plan additional amortizations are ultimately assigned by the Commission **is retired**. The Commission finds this reasonable, and approves of the stipulation's resolution of this issue.

The ten year period requirement ends August 7, 2015 since the effective date of the order in Case No. EO-2005-0329 was August 7, 2005.

Q. Was Staff's the initial proposal in compliance with this agreement?

A. Staff believes it was. However, for certain accounts there was a question if the amortizations would last longer than the ten years specified in the stipulation. So Staff felt it necessary to revise its position to be certain this part of the agreement was met.

Q. Does Staff's revised recommendation comply with the *Order*?

A. Yes. Staff anticipates that Iatan 2 will remain in service well past the August 7, 2010, date described in the *Order*.

Q. Is it the best regulatory practice to provide consumers the benefit of the accumulated additional amortizations over the life of the assets which gave raise to these Amortizations?

A. Yes. The stipulation and *Order* indicate that the accumulated additional amortizations should effectively function as an offset to rate base, benefiting customers as a reduction to the amount of capital customers are obliged to return to KCPL, in recognition that the customers have provided that capital.

Q. Why did Staff allocate the accumulated additional amortizations to the Iatan 2 plant reserve accounts, as opposed to all plant reserve accounts other than Iatan 2, as requested by KCPL?

A. Staff believes this plant asset was the main reason for KCPL's Comprehensive Energy Plan and the main support for the Regulatory Amortizations. Consequently, Staff recommends that the best regulatory practice is to apply the accumulated additional amortizations to the Iatan 2 depreciation reserves.

Q. What is Staff's recommended treatment for the accumulated additional amortizations?

A. Staff recommends the accumulated additional amortizations be used as a rate base reduction through the accumulated depreciation reserve specifically identified for Iatan 2. These accumulated amortizations should be part of the Iatan 2 depreciation reserve over its useful life. This treatment adds to the Iatan 2 depreciation reserves the total amount of the Regulatory Amortizations of $168.9 million (Missouri jurisdictional) as of December 31, 2010 made up of the assignment of the approximate $36.7 million and $132.2 million (Missouri jurisdictional) which were specifically identified at pages 39 and 40 of my direct testimony.

These amounts are currently reflected in depreciation reserves identified as account 399. Mr. Rice identifies in his surrebuttal the estimated distribution to Iatan 2 depreciation reserve accounts under this recommendation.

Q. Is it important to be able to identify the accumulated additional amortizations in the depreciation reserve?

A. Yes. KCPL must maintain a separate accounting of the accumulated additional amortizations so that they never lose their identity in the reserve accounts. Staff recommends that the accumulated additional amortizations have a separate account in the Iatan 2 depreciation reserve to always be able to separately identify this item. This treatment is the same as what KCPL has been doing for the Regulatory Amortizations since 1996 when KCPL was allowed amortizations as result of the Case No. EO-94-199. KCPL used Account 399 to identify the Regulatory Amortizations. The difference now would be that those amortizations will be separately identified with Iatan 2 depreciation reserve. Staff witness Arthur W. Rice addresses the monitoring of the additional reserves to Iatan 2 in his surrebuttal testimony.

Q. Does KCPL describe the accounting entries that would be necessary to effectuate its requested treatment of the accumulated additional amortizations?

A. No. KCPL does not provide any meaningful detail as to how exactly the accumulated additional amortizations would be tracked. The necessary accounting entries to effectuate Staff's recommendation are contained in Art Rice's surrebuttal testimony.

Q. What dollar value of accumulated additional amortizations should be used to determine rates in this case?

A. Staff's true-up case will include the $168.9 million level identified at page 40 of my direct testimony for the period ending December 31, 2010 and is reflected in the

Staff's estimated true-up revenue requirement calculation filed on November 10, 2010. The $168.9 million will be included in the actual True-up calculation prepared by Staff which is scheduled to be filed February 22, 2011.

Q. What will be the level of accumulated additional amortizations through May 2011, the effective date of rates in this case?

A. The level of accumulated additional amortizations through May 2011 will be approximately $183 million. However, all other cost components of the revenue requirement are reflected as part to the true-up cutoff of December 31, 2010, the date ordered by the Commission in its August 18, 2010 Order on Procedural Schedule. Consequently, Staff believes it would improper to include the $183 million as offset to rate base in this case.

Q. How should the $183 million amount for the Regulatory Amortizations be treated in this case?

A. The difference between the $183 million May 2011 level and the $168.9 million December 31, 2010 level, or $14.1 million, should be used as an offset for the construction accounting calculation for inclusion in future rates. Construction accounting is a deferral of certain costs of Iatan 2 that were treated as construction costs prior to its August 26, 2010 in-service date. Once Iatan 2 became operational, those construction costs were moved to plant in service. Subsequent to August 26, any costs once treated as part of the construction work order were charged to expense. These costs include depreciation and carrying costs associated with a deferred return component of the newly in-service Iatan 2 power plant. Construction accounting was agreed to in the Regulatory Plan to defer these costs until rates are effective in this case, expected to occur around May 4, 2011. Since rates in this case will not change until May 2011, the Iatan 2 post-construction costs cover a period of approximately

8 months (essentially September through April). Construction accounting is used for significant plant additions to protect the earnings of the Company during the period from in-service to effective date of rates. Staff witness Keith A. Majors addresses the treatment of construction accounting in his rebuttal and surrebuttal testimonies.

Q. What is the amount of construction accounting for Iatan 2?

A. KCPL identifies the Iatan 2 construction accounting costs of $14.3 million on a Missouri jurisdictional basis in Mr. Weisensee's rebuttal testimony (page 6, line 12). This is an expense amount KCPL proposes be amortized over a 50 year period, the Company's proposed life of Iatan 2. However, since Staff proposes Iatan 2 be depreciated over a 60 year period, that is the period the construction accounting amortization should occur. KCPL also indicates in Mr. Weisensee's rebuttal an amount of $5.5 million of deferred income tax rate base offset.

It should be noted that the $14.1 million amount for the difference in Regulatory Amortizations from December to May is a rate base amount—not an expense amount—and is not the same as $14.3 million level for construction accounting costs. The recommendation to offset the post-December 31, 2010 Regulatory Amortizations with construction accounting will have to be put on a revenue requirement basis.

HAWTHORN 5 SELECTIVE CATALYTIC REDUCTION SETTLEMENT

Q. What is the purpose of this portion of your Surrebuttal Testimony?

A. This section of the Surrebuttal Testimony is to respond to the rebuttal testimony of KCPL witness Curtis D. Blanc on the subject of settlement proceeds received by the Company in 2007 related to the performance standards of a selective catalytic reduction system (SCR) installed at Hawthorn 5. This issue is primarily being addressed by Staff witness Karen Lyons.

However, I am addressing selected portions of Mr. Blanc's rebuttal dealing with fuel and purchased power expenses.

A detailed discussion on this proposed treatment is identified in the Staff Cost of Service Report filed on November 10, 2010, at page 108 under Section E- Other Non-Labor Adjustments—Hawthorn 5 SCR Impairment adjustment.

Q. Are you familiar with the fuel and purchased power area in utility operations?

A. Yes. I have worked on fuel and purchased power costs on numerous rate cases dating back to 1982. I have directly and indirectly been involved in the review of these costs on numerous KCPL rate cases as well as rate cases involving St. Joseph Light & Power Company, now L&P, several Aquila and its predecessor, UtilitCorp United, as it relates to MPS rate cases, now known as MPS and several Empire District Electric Company rate cases. I have supervised and over seen the development of the fuel and purchased power in a numerous rate cases.

Q. Why did KCPL receive these settlements for Hawthorn 5?

A. An explosion completely destroyed the Hawthorn 5 coal-fired boiler in February 1999. This unit was substantially rebuilt from 1999 to its re-powering in June 2001. As part of the rebuilt, KCPL installed an all new, state of the art environmental equipment including a SCR. KCPL contracted with Babcock & Wilcox (B&W or Babcock) to install this environmental pollution control equipment. KCPL entered into an engineering, procurement, and construction (EPC) agreement with Babcock & Wilcox for the construction of Hawthorn Unit 5 boiler island including the SCR (the B&W Agreement or Agreement). The SCR was installed to reduce pollution associated with operating a coal-fired generating unit. Under the Agreement, B&W guaranteed specific performance standards, including an ammonia slip test. After the SCR was placed in service in June 2001, the boiler failed the ammonia slip test.

The guaranteed performance standards were part of the original contractual agreement with Babcock & Wilcox. Since this contract contained the original equipment performance standards, the contract price KCPL paid for the SCR equipment included the guaranteed performance standard. As a result, Babcock & Wilcox attempted to fix the problems starting in 2002 to meet the performance operations issues of the SCR but were ultimately unsuccessful. Problems continued to exist through 2004 when KCPL accepted a revised lower performance standard but the SCR failed to meet this lowered standard as well. KCPL received a settlement from Babcock & Wilcox in 2007.

Ms. Lyons will provide further details regarding the settlement and the contract issues in her surrebuttal testimony.

Q. How did KCPL treat the settlement?

A. The Company removed the settlement proceeds from its cost of service in its 2009 rate case because the payment fall in the 2007 test year used in that case. This removal from the test year effectively treated the SCR settlement what is commonly referred to as "below-the-line", which means the Company retains all benefits from the settlement. While KCPL customers have had to pay higher rates in each of the last three rate cases from the SCR operation and maintenance costs, and the impacts of higher capital costs—higher depreciation and higher return recovery—the Company believes it is proper to in essence, keep the money for its owner, Great Plains.

Q. Did Staff remove the settlement from the 2007 test year in the 2009 rate case?

A. Yes. But once the settlement was removed from the test year, Staff made a corresponding adjustment to reflect it as a reduction to rate base through increased accumulated depreciation expense (depreciation reserve). Since the SCR could not meet the original contract standards (and even the revised reduced standards), Staff took the position that the settlement directly related the purchase of a lowered quality piece of equipment. The SCR had a performance standard in the contract that could not be met yet this standard was part of the original contract price. Since there was a settlement to address the lowered performance, Staff took the position to assign the settlement proceeds to reduce the equipment costs. Since this was a rate base issue which carries over to other periods, it was necessary for Staff to address the rate base adjustment in the same way in this case.

Q. What is KCPL's position on the Babcock & Wilcox settlement identified in its rebuttal testimony?

A. Mr. Blanc provides four reasons in his Surrebuttal Testimony, page 49, lines 7-18, why KCPL customers are not entitled to the settlement proceeds. They are as follows:

> **(1)** The proceeds of this litigation have nothing to do with the test year in this case.
>
> **(2)** The cost of replacement power and additional ammonia expenses that resulted from the H5 catalyst outage (representing 90% of the settlement proceeds) was never paid by the customers.
>
> **(3)** To the extent KCP&L personnel were included in the process there would not have been any incremental costs to the Company or in turn its customers.
>
> **(4)** This issue represents retroactive ratemaking, which is not appropriate, where for the Company's benefit or detriment.

I will respond to item 2 above regarding purchased power and fuel costs and Ms. Lyons will respond to the other three concerns raised by KCPL witness Blanc in her surrebuttal.

Q. Does Staff agree with Mr. Blanc's contention that customers have never paid for the cost of replacement power and additional ammonia costs resulting from the problems with the Hawthorn 5 SCR?

A. No. Customers have paid increased rates resulting from the SCR performance failures. Those increased costs have been included in rates in each of the last three KCPL rate cases- Case No. ER-2006-0314 filed on February 1, 2006 (the 2006 rate case), Case No. ER-2007-0291 filed on February 1, 2007 (the 2007 rate case) and Case No. ER-2009-0089 filed on September 8, 2008 (the 2009 rate case).

Q. Did KCPL incur increased costs from the problems with the SCR?

A. Yes. Babcock & Wilcox's failure to meet the ammonia slip test standards caused KCPL to experience increased replacements of catalysts, increased usage of ammonia, plus additional cleaning and maintenance expense, all resulting in significantly higher than expected costs to run and maintain the SCR equipment. KCPL incurred higher purchased power costs and higher fuel costs directly related to the poor operating performance of the SCR. All of these costs have been reflected in rates starting with the 2006 rate case. The higher costs were also reflected in the 2007 and 2009 rate cases.

I will address the higher fuel and purchased power costs and Ms. Lyons will address the other higher costs in her surrebuttal.

Q. KCPL takes the position that customers have never paid for the fuel and purchased power costs relating performance issues of the Hawthorn 5 SCR. Is that correct?

A. Mr. Blanc claims KCPL customers have never paid for the costs of replacement power or additional ammonia expenses (fuel costs) that resulted from the Hawthorn 5 SCR catalyst outage. He states on page 50, lines 2-4, in his Rebuttal Testimony, "KCP&L did not request a rate increase at any time during the outage or subsequent to the outage that resulted in recovery of the replacement power costs and the additional ammonia expenses. Thus, customers have never paid these costs."

Q. Does Staff agree with KCPL's position that customers have not had to pay for these higher fuel and purchased power costs?

A. No. Both KCPL and Staff developed their respective revenue requirements case in Case No. ER-2009-0089 using a test year for that case based on the twelve (12) month period ending December 31, 2007. The higher ammonia costs at Hawthorn 5 for the SCR catalyst were certainly reflected in both the Company's and Staff's fuel costs. Fuel costs in the 2006 and 2007 rate cases had ammonia costs included for the Hawthorn 5 SCR.

Consequently, Mr. Blanc position that KCPL's customers have never paid for fuel expenses for the SCR operational issues is incorrect.

Q. Are plant outages included in the development of rates?

A. Yes. The plant outages are included as part of the process to develop normalized fuel costs in rate cases. The outages are averaged over a period of time generally determined when major turbine overhauls occur—5, 6 or 7 year period. To the extent the Hawthorn 5 SCR resulted in additional outages, those outages are included in the fuel analysis and used as part of the Hawthorn 5 outage averages.

Q. What is an outage?

A. An outage occurs for variety of reasons. Every power plant has planned outages – known as scheduled outages—to perform planned maintenance of equipment and systems. Generating units also have to be taken off line (shut down) for unexpected reasons for equipment failure and operational issues—these are known as forced outages.

Q. Have KCPL's customers paid purchased power costs as a result of the failed standards of the SCR?

A. Yes. In each of the last three KCPL rate cases, Staff includes purchased power costs in the fuel model. To the extent KCPL experienced purchased power costs for Hawthorn 5 plant outages relating to the SCR performance issues, then the increased purchased power costs have been included in rates.

Q. How does Staff develop its purchased power cost recommendation?

A. In each rate case, the Commission's Operations Division reviews purchase power costs along with Staff members assigned to the Auditing Department. An examination of purchased power costs and levels on a megawatt hour basis is made for the test year and, typically the update period. Consequently, in the last rate case—the 2009 rate case, the levels and amounts of purchased would have been examined based on the 2007 test year time period through the September 30, 2008 update period. By virtue of the way purchased power is done in a rate case, Staff includes a level and costs of purchased power is based on the actual purchases experienced during the time of each rate case. The following table identifies the different test years used for each of the three rate cases filed by KCPL since 2006:

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

Any increase in ammonia which has actually occurred to operate the SCR at Hawthorn 5 has been fully included in rates based on the test years and updates used in each of the past three rate cases. For Case No. ER-2006-0314, the ammonia costs would have been include for Hawthorn 5 for the 2005 test year or through the update June 30, 2006 period —the ammonia costs would have been examined for the 2007 rate case for the test year levels were 2006 updated for March 31, 2007.

Rates for the 2006 rate case went into effect January 1, 2007. To the extent these costs experienced significant cost increases, then those increases would have been part of the true-up.

Starting with the 2006 rate case through the present, to the extent that Hawthorne 5 experienced higher than normal outages, this would result in higher fuel costs. The higher fuel costs would result from the low cost Hawthorne 5 generation being replaced with higher generation cost units.

Also, Staff used actual purchased power costs for each of the test years and updated periods to set rates in each of the last three KCPL rate cases. For the 2006 rate case, purchased power was included in rates based on the actual levels experienced by the Company for the 2005 test year, updated through June 30, 2006—for the 2007 rate case the test year levels were 2006 updated for March 31, 2007.

Unquestionably, customers have paid this higher ammonia (fuel costs) and higher purchased power costs experience because of the SCR performance issues at Hawthorn 5.

Q. Did you have discussion about the increased costs for ammonia in the last rate case?

A. Yes. I specifically discussed this issue with KCPL witness Ed Blunk, who is KCPL's Supply Planning Manager. Mr. Blunk recognized that ammonia costs were going up as result of the increase in amount being used and price escalation. We talked about this issue several times during the course of the last rate case. Both the Company and Staff included significant increases in our fuel costs to reflect these increases for ammonia.

Q. Do customers pay for KCPL's fuel and purchased power costs even though it does not have a fuel clause?

A. Yes. In each rate case a substantial amount of time is devoted to the review, analysis and development of fuel and purchased power costs. Since these costs represent the most expensive part of providing electricity they have a great deal of scrutiny during each rate case filed by a electric utility. Fuel and purchased power costs are annualized and normalized to reflect the normalized net system input (normalized sales, station use, factor for line losses). These costs are developed using a production cost model—commonly referred to as the "fuel model." Other costs are included known as fuel additives—this is where the ammonia costs is needed to operate the Hawthorn 5 SCR equipment are included in the fuel costs. Fuel costs and purchased power costs reflect current prices for commodity and transportation costs.

Hawthorn 5 Transformer Settlement

Q. What is the purpose of this portion of your Surrebuttal Testimony?

A. This section of the Surrebuttal Testimony is to respond to the Rebuttal Testimony of KCPL witness Curtis D. Blanc on settlement proceeds received by the Company in 2008 related to the failure of a generating step-up transformer (GSU or transformer), located at the Hawthorn generating plant.

A discussion on this proposed treatment is identified in the Staff Cost of Service Report filed on November 10, 2010, at page 111 under Section E- Other Non-Labor Adjustments—Hawthorn 5 Transformer Settlement.

Q. Describe what the Hawthorn 5 transformer issue is?

A. When KCPL received a settlement for the Hawthorn 5 transformer failure in 2008 it recorded in its books a reduction to expenses for this settlement. In KCPL's 2009 rate case, Staff reflected this settlement as a reduction in rate base and made the same adjustment in this case. KCPL is opposed to any of the settlement being reflected in rates, asserting that none of costs relating to the transformer failure was ever included in rates and paid by customers. Staff disagrees with this position.

Ms. Lyons is addressing the details of this settlement in her surrebuttal testimony. I will address the ratemaking adjustments made for the purchased power area relating to impacts of the Hawthorn 5 transformer failure.

Q. When did the Hawthorn 5 transformer fail?

A. In August 2005, this transformer failed. In September 2005, a backup step-up transformer was installed. KCPL experienced higher fuel and purchase power costs during the initial failure of the transformer until the replacement was installed in fall of 2005. During an outage from June 6 to June 19, 2006, a new step-up transformer was installed resulting in increased purchased power and higher generating costs.

Q. Did KCPL seek damages from the transformer manufacture?

A. Yes. KCPL sued the contractors and subcontractors claiming they were responsible for the transformer failure. The case settled at the end of 2007, and was finalized in 2008 with payment made to KCPL. KCPL received a dollar settlement for the transformer failure from Siemens Power Transmission & Distribution, Inc. (Siemens).

Q. Has KCPL provided any benefits from the transformer settlement to its customers?

A. No. KCPL has not made any attempt to reflect any of the settlement in rates from the transformer failure. The Company has retained all the settlements to cover costs it claims was never recovered from customers.

However, it is Staff's position that KCPL's customers should have received the benefit of the settlement since customers have had to pay for higher costs for the transformer failure. The increase in fuel and purchased power costs relating to the transformer failure were first reflected in rates in Case No. ER-2006-0314—the 2006 rate case. Higher costs were also included in the 2007 rate case and again in the 2009 rate case.

Q. How were increased costs for the transformer failure included in rates?

A. Similar to the way the increase fuel and purchased power costs were included in rates for the Hawthorn 5 SCR discussed previously, these higher costs for the transformer failure were normalized in the last three rate cases.

Since the transformer failed in August 2005, higher fuel and purchased power costs existed in the 2006 rate case with customers paid starting in January 1, 2007, the effective date of those rates. The test year in this case was 2005 which had the higher costs reflected in KCPL's financial statements.

The way fuel costs are determined in rate cases, the increase in costs shows up through higher Hawthorn 5 outages for the 2005 transformer failure. In 2005, Hawthorn 5 was one of lowest or the lowest fuel source of KCPL's coal-fired units. Any time this unit is not generating electricity, KCPL experiences higher fuel costs. An average outage rate is determined based on Hawthorn 5's maintenance schedule, discussed above. The outage for the transformer failure decreased Hawthorn 5's availability resulting in higher fuel costs paid by consumers starting in January 1, 2007.

Q. Did the transformer failure result in increases for purchased power costs?

A. Yes. In the 2006 rate case, the 2005 test year was the basis for the purchased power expense. The fall 2005 outage for the transformer failure resulted in the need to replace the lower cost Hawthorn 5 unit with not only higher cost KCPL generation but also higher purchased power costs. This cost increase was included in rates starting in January 1, 2007.

Q. Did the 2007 rate case include any higher costs for the transformer failure?

A. Yes. The 2007 rate case used a test year of 2006. The new transformer was installed June 2006 so higher fuel costs through increased Hawthorn 5 outages occurred in this rate case by virtue of the use of average outage schedules in the fuel model. Purchased power costs also increased because this case used the 2006 test as its basis which included in the 2007 outage to install the new transformer. This cost increase was included in rates starting in January 1, 2008.

Q. Did the 2009 rate case include any higher costs for the transformer failure?

A. Yes. This rate case used a test year of 2007. The transformer failure resulted in higher fuel costs because both the 2006 and 2007 outages were included in the unit outage for the fuel model. Purchased power was also impacted for the transformer failure in this case because the 2007 test year was used as basis for this cost. Neither the 2005 nor the 2006 outages were affected the purchased levels for the 2009 case. Customers started paying the higher fuel costs starting in September 1, 2009 and continue to pay those higher rates up through the rate change in May 2011.

Q. Will rates in this case be affected by the transformer failure?

A. Yes. Both the 2006 and 2007 outages continue to be included in the outage averages used in the fuel model. These outages result in higher outage rates and therefore, higher fuel costs. Consumers will start paying higher rates for the transformer failure in May 2011.

Consequently, despite repeated statements in rebuttal testimony that customers have not paid for any of the costs of the transformer failure, such is not the case. In each of the last three rate cases and now in this fourth rate case, customers have and will continue to pay for the 2006 Hawthorn 5 transformer failure.

In the same way customers have and will pay for the transformer failure, they have and will continue to pay for the under-performing Hawthorn 5 SCR as well.

Q. Do you believe the transformer settlement should be fully retained by KCPL?

A. It would be unfair and unreasonable to customers to have to pay for all the costs associated with the transformer failure yet receive none of the benefits from the settlements. To suggest as KCPL does, that its customers are not entitled to these settlements because those customers have not incurred any of the costs is simply inaccurate and does not reflect the reality of how fuel and purchased power costs are determined in the ratemaking process.

In addition, customers have had to pay higher capital costs for the replacement transformer since its June 2006 installation because that unit was included in the 2006 rate case. Customers have had to pay the higher capital costs and higher depreciation starting in January 1, 2007 and every year since. This is more fully discussed in Ms. Lyons' surrebuttal testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes. It does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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	)))))	File No. ER-2010-0355

AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Surrebuttal Testimony in question and answer form, consisting of 32 pages to be presented in the above case; that the answers in the foregoing Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Cary G. Featherstone

Cary G. Featherstone

Subscribed and sworn to before me this 5th day of January, 2011.

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016