Exhibit No.: ______________
Issue(s): FAC Sharing Mechanism/Crossroads
Witness/Type of Exhibit: Mantle/Direct
Sponsoring Party: Public Counsel
Case No.: ER-2024-0189

DIRECT TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EVERGY MISSOURI WEST, INC. D/B/A EVERGY MISSOURI WEST

CASE NOS. ER-2024-0189

** ____ **
Denotes Confidential Information that has been redacted

June 27, 2024

TABLE OF CONTENTS

INTRODUCTION

Q. What are your name and business address?

A. My name is Lena M. Mantle, and my business address is P.O. Box 2230, Jefferson City, Missouri 65102.

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

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Senior Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the OPC.

Q. What recommendations to the Commission are you supporting in this testimony?

A. I make the following recommendations:

1. As a result of Evergy Missouri West's ("Evergy West") resource planning decisions that have resulted in a dependency on spot market energy, the Commission should modify the sharing mechanism in Evergy West's fuel adjustment clause ("FAC") from 95% customers/5% Evergy West ("95/5") to 75% customers/25% Evergy West ("75/25"); and
2. The Commission should continue the rate base treatment of the Crossroads plant as ordered in case no. ER-2012-0175 and not include in revenue requirement or the FAC any part of the cost of transmitting electricity from Evergy West's Crossroads facility in Clarksdale, Mississippi to Evergy West's customers in Missouri.

Q. What is your experience, education, and other qualifications, particularly on the topics to which you are testifying?

A. Prior to my employment at the OPC, I worked for the Staff of the Missouri Public Service Commission ("Staff") from August 1983 until I retired as Manager of the Energy Unit in December 2012. During my employment at the Missouri Public Service Commission ("Commission"), I worked as an Economist, Engineer, Engineering Supervisor, and Manager of the Energy Unit.

I began employment at the OPC in my current position as Senior Analyst in August 2014. In this position, I have provided expert testimony in electric and water cases before the Commission on behalf of the OPC. I am a Registered Professional Engineer in the State of Missouri.

Attached as Schedule LMM-D-1 is a brief summary of my experience with the OPC and Staff, and a list of the Commission cases I filed testimony in, Commission rulemakings I participated in, and Commission reports in rate cases that I contributed to as Staff.

Q. What is your experience regarding Missouri's fuel adjustment clauses?

A. After the Missouri Legislature passed Section 366.266, RSMo in 2005, enabling the electric utilities to request an FAC, I was instrumental in the development and application of the Commission's FAC rules and the FACs of the electric utilities in Missouri. I have provided testimony regarding FACs in numerous general rate cases, FAC rate change cases, and FAC prudence cases, both during my time on the Commission Staff and during my employment at the OPC.

Attached as Schedule LMM-D-2 is the *Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper* that I wrote to provide background and a description on various aspects of the FAC in Missouri. This whitepaper provides an explanation of the operation of FACs in Missouri, including the FAC of Evergy West, and the terms used in discussing Evergy West's FAC in this testimony.

Q. What is your experience regarding Missouri investor-owned electric utility long-term resource planning?

A. My experience in electric utility resource planning began in the late 1980s when I worked in the Research and Planning Department for the Commission Staff. With abundant coal plants and the addition of nuclear generation plants for two of Missouri's electric utilities,[1] it was evident that the electric utilities in Missouri had over built. Attempting to avoid another overbuilding of capacity, the Commission tasked its Research and Planning Department with reviewing the utilities' current resource planning processes and developing rules for the Commission regarding electric utility resource planning. I was a member of that team. The team did a comprehensive review of current resource planning practices of the Missouri investor-owned utilities and the current (at that time) state-of-the-art electric utility resource planning practices across the nation. Utilizing this information, the team developed resource planning proposed rules with input from the electric utilities and other parties in numerous workshops. The Commission's Electric Utility Resource Planning Chapter 22 (20 CSR 4240-22) became effective on May 6, 1993. Much later, as Manager of the Energy Department, I was also instrumental in the revisions of the Chapter 22 Electric Utility Resource Planning[2] rules ("Chapter 22"). These revised rules became effective June 30, 2011.

[1] Union Electric Company's Callaway Nuclear Plant and Kansas City Power & Light Company's Wolf Creek Nuclear Plant.

[2] At that time the word "integrated" was used to designate that demand-side resources were included in the resource planning process. With the expectation that integrating demand-side resources would become a normal part of good planning, it was decided to name this rule and process in Missouri "Resource Planning."

DEFINITIONS OF KEY TERMS

Q. What terms do you use in your testimony that are critical in understanding resource planning and the FAC?

A. It is critical to correctly understand capacity, energy, demand, and load requirement including the differences and the interactions between them. These terms are often used imprecisely yet it is important to understand and use them correctly.

Q. Would you provide a definition of capacity as it is used in your testimony?

A. I use capacity as it is defined in the Commission's Chapter 22 as follows:

> Capacity means the maximum capability to continuously produce and deliver electric power via supply-side resources or the avoidance of the need for this capability by demand-side resources.[3]

The capacity of a generation resource is the maximum output it can physically produce. With respect to utility scale generation resources, it is measured in megawatts ("MW").

Q. Would you define energy as you use it your testimony?

A. I use energy as the Commission defines energy in Chapter 22 as follows:

> Energy means the total amount of electric power that is generated or used over a specified interval of time measured in kilowatt-hours (kWh).[4]

The energy generated by utility scale generation resources is typically measured in megawatt-hours ("MWh") which is equivalent to 1,000 kWh.

[3] 20 CSR 240-22.020(4).
[4] 20 CSR 240-22.020(19).

Q. Both of these definitions are a measure of electric power. Can they be used interchangeably?

A. No. While capacity and energy are often used interchangeably, they should not be. They are measurements of different aspects of electricity.

Q. Are they related?

A. They are related to the extent that both are impacted by design and usage of a given generating unit. To clarify, consider this example: there is a sign in the elevator that states its capacity, *i.e.* how many people the elevator can hold at a given time. This limits the amount of people that can be in the elevator at any given time. However, it gives no information on the number of people that ride in the elevator each day. In a given day the elevator may make 10 trips with 20 people each time meaning 200 rides (10 x 20) were given. The next day the elevator may not move because the building is closed resulting in zero rides being given that day. The capacity is the same, 20 people, no matter how many rides are given. However, the number of rides given cannot be determined from the capacity of the elevator.

Similarly, the capacity of a generator is the limiting criteria for the maximum amount of energy a generator can produce. A plant with a capacity of 100 MW cannot generate 200 MWh of energy in any given hour just as an elevator with a capacity of 20 people cannot hold 40 people. However, it is not correct to say that same plant is producing 100 MWh of energy at every hour of every day just as that same elevator is not necessarily carrying 20 people with every trip. The capacity and energy produced by the generator are thus related, in as far as they are dependent on its design, but are measuring very different things.

Q. The Commission's definition of energy includes the total amount of electric power that is used over a specified interval of time. How is this connected to the energy that a power plant produces?

A. Energy is a term that is also used as a measurement of how much electricity a customer or group of customers consumes over a period of time. Electric utilities are required to meet the energy requirements of their customers.

Q. Is this energy requirement also referred to as load requirement?

A. This is one measure of load requirement. Load requirement is measured in peak demand and energy. Peak demand (or demand) is the highest amount of electricity used over a set time-period. Each day has a peak demand as does the week, month, and year. The energy is the sum of the hourly demands over the set time period.

The following example should help explain this. If over ten hours, a customer uses 50 MW in nine hours and 550 MW in one hour, then the customer's peak demand in that ten hours is 550 MW (the maximum amount of energy used in an hour over the ten hours) and the energy used over that ten hours is 1,000 MWh. (1,000 MWh = (50 MW x 9 hours) + (550 x 1 hour)). In this testimony, when I use the words "load requirement" or "load" I am referring to both the peak demand and energy of the customers.

Q. Would a resource that provides 1,000 MWh over that ten hours be able to meet this load requirement?

A. Not necessarily. The table below is provided to help explain the differences between these terms.

Table 1
Example of Peak, Capacity, and Energy

Hour	Customer Demand	Generator A	Generator B
1	50	100	0
2	50	100	0
3	50	100	0
4	50	100	0
5	550	100	550
6	50	100	0
7	50	100	0
8	50	100	0
9	50	100	0
10	50	100	0
Total	1,000	1,000	550
Peak (MW)	550		
Capacity (MW)		100	550
Energy (MWh)	1,000	1,000	550

In this example, the peak demand for the customer over these ten hours is the maximum hourly demand of 550 MW. The energy needs of the customer is the sum of the demands of each hour or 1,000 MWh. This is the load requirement that the utility is required to meet – both the peak and the energy needs of the customer.

Generator A has a capacity of 100 MW. That is the maximum it can generate in an hour. If it generated its maximum every hour for these ten hours, then it could generate 1,000 MWh of energy. However, it cannot meet the peak demand of the customer of 550 MW since the most it can produce is 100 MW.

Generator B has the capacity to meet the peak demand of the customer of 550 MW. However, it cannot meet the load requirement of the customer in the other nine hours.

<u>EVERGY WEST'S FAC SHARING MECHANISM SHOULD BE MODIFIED TO 75% CUSTOMERS /25% EVERGY WEST</u>

Q. Why are you recommending the Commission modify the sharing mechanism in Evergy West's FAC to 75% customers/25% Evergy West?

A. The current sharing mechanism of 95% customers/5% Evergy West has not provided Evergy West enough of an incentive to prudently meet the energy needs of its customers. Evergy West has continuously made the resource planning decision to rely on the SPP energy market to meet the energy needs of its customers instead of building or acquiring cost-effective generation that meets the energy needs of its customers. Based on my experience with Evergy West and its predecessors, KCP&L – Greater Missouri Operations Company, and Aquila, Inc., I am confident that if Evergy West did not have an FAC, it would have acted differently, putting steel in the ground, or entering into long-term firm contracts for the provision of energy instead of relying on the volatile SPP energy market.

Q. What demonstrates that Evergy West is relying on the SPP energy market?

A. Evergy West pays SPP for every MWh of energy used by its customers and receives revenue for every MWh it produces. Table 2 below shows, for the last four prudence periods,[5] the cost of energy from the SPP market to meet customer load requirements and the revenues from generation sold to SPP for Evergy West and Evergy Metro from Staff's filed prudence reports.

[5] December 2016 through November 2022 for Evergy West. January 2017 through December 2022 for Evergy Metro.

Table 2

Energy Market Margin by Prudence Period

** **

Over these four prudence periods, Evergy West has spent $748 million more on non-firm short-term energy for its customers than it received in revenues from the SPP market. This does not include the $314.6 million costs of Storm Uri in February 2021. At the same time, its sister utility, Evergy Meto, received revenues above what it paid of $465 million. That is a $1.2 BILLION swing between two utilities that faced the same market, the same weather, and have the same management. The difference between the two utilities is that during the six calendar years of 2017 through 2022, Evergy Metro had generation above what its customers needed and Evergy West relied on the SPP market for approximately half of the energy its customers needed.[7]

[6] February 2021 short-term energy costs and off-system sales revenues are normalized due to Storm Uri.

[7] The workpaper that shows this calculation is provided as Schedule LMM-D-3.

Q. What is the relationship between resource planning and the FAC?

A. Electric utility resource planning decisions directly impact the costs and revenues that flow through the FAC for decades after the decision. Market prices that change every five minutes are mitigated by decisions to acquire "insurance" (generation resources) that can take years to implement, *i.e.* build, and which are intended to meet customers' needs for decades. Consequently, the "incurrence" of the cost of fuel, whether it be uranium, coal, natural gas, or oil, and purchased power cost that is passed to customers through an FAC is set in motion by the decision decades earlier by the electric utility to not build, or to build and what to build.

Q. What is resource planning?

A. The Commission defines resource planning as:

> Resource planning means the process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side, demand-side, and distribution and transmission resource additions and retirements to provide the public with an adequate level, quality, and variety of end-use energy services.[8]

Resource planning decisions are a minimization of fixed costs (*e.g.* cost to build a plant) and variable costs (*e.g.* cost to run a plant that are included in the FAC) taking into account market prices, reliability concerns, and critical uncertain factors. Each resource type has unique characteristics. A prudent resource plan results in a resource portfolio that meets the load requirements of the utility's customers utilizing the characteristics of the various resources, both demand and supply side, to minimize price volatility while assuring customers a reliable source of energy to cost-effectively meet their energy needs.

[8] 20 CSR 240-22.020(53).

Q. Why is electric utility resource planning so complex?

A. Electricity is a secondary energy source. It results from the conversion of other energy forms such as natural gas, coal, or uranium, or the energy inherent in wind, sunshine, or the flow of water in a river. There are also a number of different ways to convert these energy forms to electricity making the task of determining the optimal sources to meet projected customer load requirements across various futures while minimizing costs and meeting reliability requirements a very complex task.

For example, a nuclear plant is designed to run continuously and has a low, stable fuel cost. It would not be appropriate to build a nuclear plant if the need was only for a few hours of the year when it is really hot because of the large, fixed cost of building nuclear resources. Likewise, a natural gas combustion turbine ("CT") would not be appropriate to meet the constant energy requirements of a large data center. It is relatively inexpensive to build but, across decades, its fuel costs can be volatile and, as utilities have experienced during the past few years, the natural gas supply can be disrupted. CTs are not the most efficient generators of electricity and are not designed to run continuously for long periods of time. Due to the risk of volatile fuel cost, potential for supply disruptions, and the CTs design, it is not the appropriate type of resource to meet the continuous, large load requirements of a data center. However, since CTs can be dispatched as needed, using natural gas CTs to meet energy requirements that only exist a few hours of the year is more cost-effective than resources with high fixed costs but low variable costs to generate electricity.

Q. What about renewable generation resources like wind and solar?

A. Like natural gas and coal generation, renewable generation has its benefits and owned wind and solar have no fuel costs. However, they have limited availability that does not always match customers' load requirements restricting their applicability. Solar is typically available during the hottest days of the year when cooling load is the greatest and market prices are high. However, if the need is for electricity to heat buildings in the winter, solar is unavailable in the middle of the night when it is the coldest. Wind energy may be available during those cold windy nights but is often not available in the hot humid nights of summer. Too much dependence on energy from renewable resources often leaves the utility at the risk of not having adequate energy to meet its customers' needs and having to buy energy from the market at times when prices are high. While these low-cost energy resources are valuable, their limited availability needs to be properly accounted for in the resource planning process.

Q. Is there a role for purchased power in the resource planning process?

A. Yes. There are two types of purchased power, bilateral contracts also known as purchased power agreements ("PPA") and energy market purchases. Both have a role in resource planning. However, the availability and pricing of PPAs is determined by the overbuilding of other utilities or the ability of the power producer to make a profit – risks that need to be taken into account in the resource planning process.

Q. Would you explain the role of PPAs in resource planning?

A. Purchased power contracts for capacity and/or energy are a tool that can, and should, be used to fill small gaps in resource planning. Generation resources are typically added in bulk. Load typically increases in small increments. PPAs can be useful to delay the addition of a resource for a few years waiting for load to grow into the bulkiness of a resource. However, PPAs also have limitations. Purchased power contracts for capacity, like Evergy West has with its sister utility Evergy Metro, typically do not include a cost for energy from the resource. This means the utility ends up purchasing energy from the market. If a utility has an FAC like Evergy West that includes the cost of purchased power, relying on the market results in the risk of volatile market prices being placed, not on the utility that entered into the capacity only contract, but on the customers that have no role in resource planning.

Q. Can having an FAC influence resource planning decisions?

A. Yes. Without a FAC, the utility is responsible for net energy and purchased power costs above what are included in permanent rates. This means that the utility itself is exposed to the risk of any major price fluctuations in the cost of fuel or the energy market. If fuel and purchased power costs are greater than what is included in rates, the utility absorbs the increased cost and can come to the Commission requesting a general rate increase to cover future increased costs. If there is no FAC, the utility would want to take out platinum "insurance" *i.e.* building whatever resources it believes is necessary to minimize its risk of having to absorb any energy related costs that might arise due to this risk.[9]

Having a FAC removes the risk of the utility not recovering its fuel and purchased power costs and places the risks of the utility making an incorrect resource planning decision on its customers. Increasing fuel or market prices are just passed on to customers with negligible impact on shareholders.[10] Some resource planning decisions, such as entering into PPAs with no capacity charges (only charges for energy which are recoverable through the FAC), remove all risks

[9] Without a FAC, the utility also gets to retain the savings when net FAC costs are below what are in permanent rates. In Missouri a FAC is optional. The electric utilities have determined the likelihood of costs below what is included in rates is low and the risk that costs will be above what is included in rates is unacceptable and all have requested, and received, an FAC. Thus, all this risk that was unacceptable to the utility is now on its customers.

[10] The costs and revenues used to determine the FAC base factor are included in revenue requirement, *i.e*, there is a base amount of fuel and purchased power costs included in permanent rates. Evergy West's FAC includes a 95/5 sharing of the net costs **above** the FAC costs and revenues that are included in permanent rates. The impact on cost recovery of total FAC costs (cost recovered in permanent rates plus cost recovered in the FAC rate) given variances from the FAC costs included in permanent rates is described on pages 12 – 13 of the FAC whitepaper attached as Schedule LMM-D-2. This whitepaper shows that, even when actual costs are 150% of the FAC costs included in base rates, Evergy West would recover over 98% of the total actual FAC costs it incurred.

of building plant from the shareholder and puts all the risk of increased energy costs on the customers. The same is also true of short-term capacity contracts that do not include energy.[11] With an FAC, if the utility builds, the shareholders earn a return on the capital investment and recover costs while the customers get the advantage of the hedge of the generation plant. If the utility does not build and instead choses to rely on the RTO, it can use the capital to invest in other areas and not worry about the shareholders having to pay if the market goes wild. The customers see lower base rates but are exposed to the volatility of the market and hence may pay even higher bills due to increased FAC costs.

Q. Has having an FAC affected the resource planning of Evergy West?

A. Yes. While it is not obvious in the resource planning documents filed with the Commission, Evergy West's action, or in this instance inaction, speaks louder than words in a resource planning document. In the last resource plan that Evergy West, then known as Aquila, filed prior to being acquired by Great Plains Energy, Inc.,[12] Aquila estimated that under normal conditions its generation resources could only generate 74% of the energy its customers' need, *i.e.* it was depending on the market to cover at least 26% of its customers' load requirements. To correct for this fact, Aquila's preferred resource plan was to add ** **[13] These proposed owned resources were in addition to its 153 MW portion of the Iatan 2 coal plant that was under construction at that time.

SPP did not have a day-ahead energy market and no investor-owned electric utility in the state of Missouri had an FAC when Aquila filed this resource plan that

[11] Evergy West's FAC includes the capacity costs of PPAs of less than one year.

[12] Now known as Evergy, Inc.

[13] Case No. EO-2007-0298, *In the Matter of the Resource Plan of Aquila, Inc. d/b/a Aquila Networks MPS and Aquila Networks L&P pursuant to 4 CSR 240-Chapter 22.* The capacity balance sheet for Aquila's preferred plan in Case No. EO-2007-0298 is attached as Schedule LMM-D-5.

showed that the best resource plan for Aquila and its customers was to add 775 MW of capacity. Aquila's preferred resource plan was to "buy" the proper insurance policy (*i.e.* building generation resources) it believed was necessary to minimize its risk of having to absorb any energy related costs. This behavior changed drastically once the Commission approved an FAC for Aquila.

The Commission approved an FAC for Aquila effective July 5, 2007, five months after this resource plan was filed with the Commission.[14] The only resource additions by Aquila, now known as Evergy West, since the time the Commission approved an FAC for Aquila has been (1) PPAs for wind energy that Evergy West claims that it entered into <u>not</u> to meet their customers' energy requirements (or to meet Missouri renewable energy standards), but for what Evergy West has termed "economic reasons,"[15] and (2) the merchant Crossroads Energy Facility when Evergy West's parent company could not get any buyers for it. No other resources have been added to Evergy West's resource portfolio despite Aquila's 2007 resource plan that showed that it needed to add 775 MW of owned generation capacity by 2023.[16]

In addition to not adding any resources to meet its customers' load requirements since the filing of that preferred plan, Evergy West retired the only coal plant of which it had sole control in 2018 reducing its capacity by 400 MW. Evergy West did not add any resource to replace the capacity or energy generation capabilities of this plant that it showed running through the entire 20-year planning horizon in its 2007 preferred resource plan.

[14] Case No. ER-2007-0004, *In the Matter of Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks-L&P, for Authority to File Tariffs Increasing Electric Rates for the Service provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Service Area.*

[15] It projected that these PPAs would create revenues from the SPP energy market greater than the contracted price for these PPAs thus being "economic."

[16] Evergy West has acquire 22% of the Dogwood facility as of June 1, 2024.

As a result of these decisions, Evergy West is now facing both a substantial capacity and energy shortage. In its latest resource plan update, Evergy West estimates it can only generate 56% of the energy its customers needed in 2023.[17] Evergy West relies on its sister utility Evergy Metro's excess capacity to meet its SPP reserve requirement and on the energy supplied through SPP's day ahead market to meet the remaining 44% of its customers' energy needs.

Q. How does this demonstrate that having an FAC has impacted Evergy West's resource planning?

A. The drastic change between what Evergy West (then Aquila) intended to do prior to receiving an FAC and what occurred after the Commission approved the Company's FAC clearly indicates that the FAC changed the Company's resource planning strategy. Being a member of the SPP has assured Evergy West that there will be energy for it to purchase. The development of the SPP day-ahead energy market means Evergy West does not have to enter into bilateral contracts for that energy. Having an FAC means it can recover from customers the costs it incurs by relying on others for energy through PPAs and the energy market. This gives it the resource planning option of not having to expend capital and meet its customers' needs, with very little risk being placed on its shareholders. Having an FAC removes the risk of Evergy West not recovering its fuel and purchased power costs and places the risks of Evergy West making an incorrect decision on its customers.[18] The cost of energy

[17] EO-2024-0154, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2024 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*, Volume 1 - Evergy Missouri West Executive Summary, Tables 1 and 2.

[18] While Section 386.266.5(4) RSMo. requires a prudence audit no less frequency than 18-month increments, finding and proving imprudence is a difficult task and is a minimal risk for the utility.

from the market is just passed on to customers with negligible impacts on shareholders.[19]

Q. Would Evergy West have built resources if it did not have an FAC?

A. Based on my history with utilities in Missouri, I believe it would have. Prior to being granted an FAC, the electric utilities in Missouri rates were set to recover the normalized fuel and purchased power that was included in permanent rates. If actual costs were below the normalized fuel and purchased power amount included in the rates, the utility was praised for being wise in its procurement of and the savings of fuel and purchased power costs increased its earnings. Savings were not passed to the customers. However, customers had stable rates that did not change every few months.

If fuel and purchased power costs were above what was included in rates, the utility was considered the victim of a volatile market and it had to absorb the increased cost. If the increased costs continued or became very large and the utility was not able to offset the increase with savings in other operations, it would request an increase in its rates from the Commission in a general rate case where all costs and revenues were examined. Customers' rates only increased after a review of all costs – fuel and non-fuel.

With no FAC, the utility would take out platinum "insurance" i.e. building whatever resources it believed was necessary to minimize its risk of having to absorb any energy related costs. Customers paid the capital costs of building the plant in exchange for stable rates.

[19] Absent the Commission ordering an imprudence adjustment in the eleventh prudence audit case, case no. ER-2023-0277, Evergy West will recover 98% of its FAC costs in the last prudence period where the actual cost incurred were 166% of the FAC costs billed through permanent rates.

Q. Has the maturing of the energy markets of the regional transmission organizations ("RTO") changed resource planning for load-serving entities such as Evergy West?

A. Yes, but if balancing customer cost and risk is considered, it has not changed materially. Reliance on the energy market is an additional resource choice to meet customers' load requirements.[20] Because the RTOs assure reliable power for its load serving members as a whole, reliance on the spot market becomes an option for RTO's members that serve customers. This option, like other resource options has benefits, *e.g.* assurance that there will be energy, and risks, *e.g.* market prices can be volatile, that should be analyzed before being chosen as part of a utility's resource plan.

Q. What about resource planning has not changed?

A. The objective of resource planning for investor-owned utilities that are members of RTOs is still the same as it was before joining the RTO – to provide the public with energy services that are safe, reliable, and efficient at just and reasonable rates. As I describe in my whitepaper, *Resource Planning of a Vertically Integrated Utility in an RTO World*, attached to this testimony as schedule LMM-D-4, a prudent utility "does not cede to the RTO the electric utility's responsibility of providing its customers reliable service at a reasonable rate."[21] It is the RTO's responsibility to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices <u>on behalf of all its members</u>. It is the utility's responsibility to provide its customers with safe and adequate service at rates that are just and reasonable.

[20] Building to "beat the market" becomes another option.
[21] Pg. 1.

Q. Is Chapter 22 still relevant?

A. Yes. Chapter 22 is still relevant and applicable. The development of data specific to the utility, the required analysis of that data, and the consideration of risk and uncertainty as prescribed in Chapter 22 are best practices for long-term planning in every industry. Resource planning without consideration of this data is incomplete and imprudent.

In addition, Chapter 22 requires utility management to make the decisions, not the regulators. The size of Chapter 22 is due to the complexity of factors that should be considered and the type of analysis, *e.g.* risk and uncertainty analysis, that should be conducted in prudent planning.

Finally, Chapter 22 contains a provision for the utility to request a waiver or variance from rules 20 CSR 4240-22.030 through 20 CSR 4240-22.080.[22] If a utility believes that any part of these rules is no longer applicable, it can ask the Commission to waive the rule. Very few waivers have been requested in the last 20 years but all that have been requested have been granted.

Q. Does that mean that the preferred plan in a utility's resource planning filing that meets the rule requirements is prudent?

A. No, it does not. The Commission explicitly states in Chapter 22:

> Consistency with an acknowledged preferred resource plan or resource acquisition strategy does not create a rebuttable presumption of prudence and shall not be considered to be dispositive of the issue.[23]

Resource planning is a modeling exercise meant to inform decision making. Like any modeling exercise, the results of a model are only as good as the data put in the model. Likewise, resource planning, as with any modeling exercise, the input data can be manipulated to give a desired answer.

[22] 20 CSR 240-22.080(13).
[23] 20 CSR 240-22.080(17).

Q. Is total reliance on an RTO for energy an option?

A. Theoretically, yes.[24] But it is an extreme option that would subject the member to the full volatility risk of the market and require other members to have capacity greater than their loads. Generation resources are hedges or "insurance" against price volatility in the SPP market. The better the generation resources match the load, the lesser the price volatility risk.

Q. Would you explain how having generation is a hedge against volatility in the market?

A. I will explain with a simple example with three utilities. In this example hour, each utility has an energy requirement of 100 MWh. In the example hour, the market price is $45/MWh. Because the load requirement is the same for all three utilities, the energy market cost of $4,500 is the same for all three utilities ($45/MWh x 100 MWh).

The generation resources of these three utilities are all different as shown in Table 3 below.

Table 3
Generation Resources

Utility	A	B	C
Available Generation			
Plant 1			
MWh	50	50	50
Variable Cost/MWh	$20	$20	$45
Plant 2			
MWh	100	50	
Variable Cost per MWh	$40	$45	

[24] Theoretically, a utility could enter into capacity only contracts to meet its resource adequacy requirement. Again, this is a simplistic explanation.

Utility A generates more energy than its customers need. It has two plants with variable costs of $20/MWh and $40/MWh that it has bid into the market at those prices.

Utility B also has two resources. These combined resources can generate 100 MWh thus covering its customers' energy needs. It has bid these two resources into the market at their variable costs of $20/MWh and $45/MWh.

Utility C only has one resource and that resource can only generate enough to cover half of its load. Utility C bids it into the market at its variable cost of $45/MWh.

Because all the plants are bid into the market at or below the market price of $45/MWh, the RTO dispatches all the plants to meet its load. Table 4 shows the calculation of the revenues and costs for each of the utilities.

Table 4
<u>Example RTO Energy Market Variable Cost to Meet Load</u>

Utility	A	B	C
Plant 1			
MWh Produced	50	50	50
Revenue Received	($2,250)	($2,250)	($2,250)
Variable Cost ($/MWh)	$20	$20	$45
Variable Cost Incurred	$1,000	$1,000	$2,250
Plant 2			
MWh Produced	100	50	
Revenue Received	($4,500)	($2,250)	
Variable Cost ($/MWh)	$40	$45	
Variable Cost Incurred	$4,000	$2,250	
Total			
MWh Produced	150	100	50
Revenue Received	($6,750)	($4,500)	($2,250)
Variable Cost Incurred	$5,000	$3,250	$2,250

The revenue received is the MWh produced multiplied by the market price of $45/MWh. Utility A's plants generate 150 MWh so it receives revenue of $6,750 (150 MWh x $45/MWh). Its variable costs are $5,000 ((50 MWh x $20/MWh) + (100 MWh x $40/MWh)). Utility B's plants generate 100 MWh so it receives $4,500 ($45/MWh x 100 MWh) in revenue for that generation. Its variable costs are $3,250 ((50 MWh x $20/MWh) + (50 MWh x $45/MWh)). Utility C's plant generated 50 MWh so it received $2,250 (50 MWh x $45/MWh). Its variable cost is also $2,250 (50 MWh x $45/MWh).

The net market cost is the energy market cost minus the revenues received for the generation plus the variable cost incurred for that generation. Table 5 shows the net market cost for each of these utilities for this hour. The net market cost per MWh is the net market cost divided by the energy requirement of 100 MWh.

Table 5
Example Net Market Cost @ $45/MWh

Utility	A	B	C
Energy Market Cost	$4,500	$4,500	$4,500
Revenue Received	($6,750)	($4,500)	($2,250)
Variable Cost Incurred	$5,000	$3,250	$2,250
Net Market Cost	$2,750	$3,250	$4,500
Net Market Cost per MWh	$27.50	$32.50	$45.00

The net market cost for Utility A, that had generation above its customers' energy need, is the lowest of the three. It paid the market price of $45/MWh for every MWh its customers needed (100 MWh). It also received $45/MWh for every MWh its generation provided the RTO (150 MWh). Because it had generation above the needs of its customers and the variable costs of these plants were below the market price, its generation provided net revenues that offset the energy market price and resulted in a realized net market price of $27.50/MWh ($2,750/100 MWh) – well below the RTO energy market price of $45/MWh. The first 100 MWh of generation offset its load cost. The next 50 MWh of generation provided revenue greater than variable cost (profit) that was used to offset the variable cost of the first 100 MWh. Utility A's generation was a good hedge against market prices because of its low variable cost and it could generate in excess of its customers' energy needs.

The net market price of $32.50/MWh for Utility B, that had enough generation to cover its customers' energy needs, was below the energy market price of $45/MWh too. This was because one of its plants had a variable cost of $20/MWh; well below the market price. The net revenues from this plant reduced the net market price. Because Utility B had generation equal to the energy needs of its customers, it had a hedge against market prices. When market prices are above $45/MWh, it provides a greater hedge. When the market prices are lower than $45/MWh, then Utility B can obtain energy cheaper than its marginal price to generate energy itself. Its units are a hedge against market prices greater than $45/MWh.

The net market price of $45/MWh for Utility C is the same as the energy market price. It had generation that it offered into the market but the variable cost of that unit was the same as the market price. Therefore, there were no revenues in excess of the cost to run the plant.

Q. If the market price was higher than $45/MWh, would this plant be a hedge against market prices for Utility C?

A. Yes. But this generation is only a hedge for 50 MWh of its customers' needs. Its customers' energy needs above 50 MWh would be left at the whims of the market.

Q. Are there benefits to relying on the energy market to meet customers' energy needs?

A. A utility that does not have cost-effective resources that can meet its customers energy requirements, has two choices; (1) enter into a bilateral contract for capacity and energy from a utility that has excess generation, or (2) enter into a bilateral contract for capacity on and rely on the energy market. The obvious benefit to both of these is that there is no expenditure of the utility's capital to build a resource. However, due to the existence of an energy market, the provider of a bilateral contract for energy would most likely want to price the energy above what it believes it could get from the market. The detriments are the risk of the bilateral contract price being above what the utility would pay in the market or, in the case of relying on the energy market, the risk of volatile market prices.

Q. Why are market prices volatile prices?

A The market prices are driven by supply and demand. When there is a surplus of resources across the RTO, there is excess supply and energy prices are likely to be low. However, as resources tighten up and older low-cost resources are retired, the market prices will increase. On a shorter-term basis, the large amount of zero-variable cost, fluctuating renewable energy results in swings in market prices as the saturation of non-dispatchable resources in the RTO increases. Similarly, when the marginal unit is a natural gas plant, the price of natural gas sets the variable cost. When the cost of natural gas is volatile so is the market price.

Also, as experienced during extreme winter weather in the past four years, restrictions on fuel supply at times of high demand leads to extreme market prices and very high-cost resources being called upon. These are the characteristics and risks of relying on market energy that should be included in any evaluation of market energy as a resource.

Q. What would be the results if your example used a market price of $90/MWh?

A. Table 6 shows the net market cost when the market price is $90/MWh.[25]

Table 6

Example Market Price @ $90/MWh

Utility	A	B	C
Energy Market Cost	$9,000	$9,000	$9,000
Revenue Received	($13,500)	($9,000)	($4,500)
Variable Cost Incurred	$5,000	$3,250	$2,250
Net Market Cost	$500	$3,250	$6,750
Net Market Cost per MWh	$5.00	$32.50	$67.50

As demonstrated in this scenario, Utility A with excess generation does very well when market prices are high as the revenues generated from the sale of energy almost covers all of the variable cost too. However, this lower net market cost will be offset by higher base rates that include the cost of excess generation plant.

The net market cost of Utility B is the same as it was when market price was $45/MWh. Because it has enough generation to cover its customers' energy needs, the net market cost is the variable cost of its generation. It has hedged its customers' total load while not increasing base rates to recover cost of generation that is not needed.

Because Utility C has a hedge for half of its load, its net market cost of $67.50/MWh is below the market cost of $90/MWh but more than double Utility B's net market cost of $32.50/MWh.

Q. What would happen if the market prices for energy were lower? For example, what would be the results if your example used a market price of $18/MWh?

A. Table 6 shows the results when the market price is $18/MWh.[26]

[25] The workpaper for table 6 is attached as Schedule LMM-D-6.
[26] The workpaper for table 7 is attached as Schedule LMM-D-6.

Table 7
Example Net Market Cost @ $18/MWh

Utility	A	B	C
Energy Market Cost	$1,800	$1,800	$1,800
Revenue Received	$0	$0	$0
Variable Cost Incurred	$0	$0	$0
Net Market Cost	$1,800	$1,800	$1,800
Net Market Cost per MWh	$18.00	$18.00	$18.00

None of the plants of these three utilities were dispatched because they were bid in above the market price. The net market cost in this example is $18/MWh for all three utilities. In this hour, it is least cost to purchase from the market than it would have been to generate to meet the customers' energy needs. This is a benefit of belonging to an RTO regardless of how much generation a utility owns. Members get the benefit of other utilities' low-cost energy.

Q. Looking at the results from your examples, is having excess generation the most prudent decision?

A. Not necessarily. Of the three utilities, the net market price of Utilities A and C are volatile. However, because Utility A and B have generation to cover their loads, there is a cap on the net market cost of their variable costs. Utility C's cap is whatever the market price is.

My examples looked at only energy market costs. Each generation resource also has fixed costs that were not included in determining cost to the customer. Of the three utilities, Utility A, which has the greatest hedge with net market prices ranging between $5/MWh and $25.50/MWh, would have the greatest fixed cost because it has the most generation. Utility C would have the least fixed cost because it has the least amount of generation. But it has enormous market risk. Across these three hours its net market price ranged from $18/MWh to $67.50/MWh. Utility B, that has generation enough to meet its load, has a full hedge against the market and some fixed cost. Its net market cost in hours that it has generation dispatched equal to load will be its variable cost of $35/MWh for the revenues it generates will be the same as the cost for energy. If the market price is less than its variable cost, then the cost will be below $35/MWh. It is the most prudent if its resources are cost-effect and efficient.

Q. What is Evergy West's position regarding the importance of having generation resources?

A. It is Evergy West's position that reliance on the energy market for energy to meet customers' needs exposes customers to a volatile market.

Q. What support do you have for the previous answer?

A. There have been three Evergy West witnesses in recent cases before this Commission that have provided Evergy West's position on the importance of having generation that support OPC's position that reliance on the energy market is imprudent. In case no. EA-2023-0291 ("the *Dogwood* case"), Mr. John J Reed was hired by Evergy West to offer testimony regarding Evergy West's application for Commission approval to acquire a portion of the Dogwood Energy Facility. In that case Mr. Reed directly acknowledge the risks involved in buying energy off the RTO energy market:

> Energy prices in the wholesale market can be volatile and increase the risk of high costs for power purchases to meet load.[27]

Mr. Reed also outlined three ways that electric utilities could meet their customer's energy needs:

> There are various resource strategies by which the utility can meet customers' needs in a cost-effective manner with acceptable risks. One strategy is for utilities to own resources that provide services to their customers, which provides more control over and certainty of

[27] EA-2023-0291, Reed direct testimony, pg. 7.

> deliverability for meeting customers' needs. This approach also limits exposure to adverse pricing in wholesale electricity markets as the services are effectively self-provided through ownership.
>
> An alternative is to meet these needs through bilateral contracts with pre-determined pricing for energy, capacity and ancillary services. This approach also typically provides a hedge against adverse pricing in wholesale markets but is generally a shorter-term solution and thus is subject to adverse pricing in subsequent rounds of contracting. A third alternative is to rely on broader wholesale market mechanisms to meet the needs of customers. This approach imposes the most price and resource sufficiency risk on the utility.[28]

As I described earlier in this testimony, because Evergy West has a FAC, "this price and resource sufficiency risk" testified to by Mr. Reed is not on Evergy West, but rather, is transferred to Evergy West's customers through the 95/5 sharing mechanism.

Q. Who is the second Evergy West witness that provides Evergy West position for how the load requirements of its customers should be met?

A. Evergy West also offered the testimony in the *Dogwood* case of Ms. Kayla Messamore, its Vice President of Strategy and Long-Term Planning.[29] Ms. Messamore presented a nearly perfect recitation of the risks and problems associated with the Company's current heavy reliance on the SPP energy market to meet its customers' load requirements.

To begin with, Ms. Messamore clearly articulated that "EMW has near- and long-term needs for <u>physical capacity, physical energy, and a hedge against the SPP energy market."</u>[30] (emphasis added). With regard to Evergy West's need for energy, Ms. Messamore explained:

[28] *Id*., pg. 12.
[29] EA-2023-0291, Direct testimony of Kayla Messamore, pg. 1.
[30] *Id*., pg. 3.

> [M]arket capacity like the capacity EMW purchases from Evergy Metro only includes mutually agreed upon market energy (or no energy at all), which doesn't provide a long term energy hedge. As a result, the amount of capacity currently covered by these market capacity purchases (240 MW in 2026) represents an incremental need for energy available on the EMW system to meet customer needs. This need for energy can, and has, been met by the wholesale energy market, but this dependence on the energy market can create risk if it is covering a large portion of customer needs for the long-term.[31]

(Emphasis added).

It is at this point that it becomes necessary to remember that Evergy West has been "dependent" on the energy market for *at least* 26% of its energy needs since 2012 as I testified in my direct testimony in case no. EO-2023-0277.[32] And that this amount has since grown to 56% as of the Company's latest resource plan filing.[33] This is the whole basis of the reason that the sharing mechanism needs to change. Evergy West has already "created risk" by "covering a large portion of customer needs" over a very "long term."

Ms. Messamore's testimony becomes even more important when she turns to the question of hedging against market energy prices. To "hedge" is "to use two compensating or offsetting transactions to ensure a position of breaking even; esp., to make advance arrangements to safeguard oneself from loss on an investment, speculation, or bet, as when a buyer of commodities insures against unfavorable price changes by buying in advance at a fixed rate for later delivery."[34] In her testimony in the *Dogwood* case, Ms. Messamore was asked this question: "In prior

[31] *Id.*, pg. 11 – 12.
[32] EO-2024-0277, OPC witness Lena M. Mantle Direct, pg. 12.
[33] EO-2024-0154, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2024 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*, Volume 1 - Evergy Missouri West Executive Summary, Tables 1 and 2.
[34] BLACK'S LAW DICTIONARY 869 (11th ed. 2019).

testimony, Staff implies that there is not a need for energy, but rather a need for a hedge against market energy prices. Do you agree with this perspective?" She responded: "No. These two needs are not mutually exclusive and EMW has a need for both."[35] (emphasis added). She then went on to elaborate:

> In addition, a strategy of relying on wholesale capacity and energy does not provide a hedge for EMW to mitigate its exposure to energy prices. As I will describe in more detail later in this testimony, a large portion of EMW capacity consists of inefficient, high heat rate natural gas turbines which operate very infrequently, as Company Witness Carlson explains. EMW leans on the more economic wholesale market to provide energy when these units aren't dispatched due to being "out of the money". Effectively, this results in EMW being a price taker any time the wholesale market is cheaper than the operating costs of its natural gas turbines, which is a significant portion of the time.
>
> [. . .]
>
> In the same way, some of EMW's market capacity contracts also make it a price taker because those contracts do not include corresponding energy. The capacity contracts that do include an energy option are only set at mutually agreeable market prices at the time of transaction. That is the need for an energy hedge which Staff references and which is very real for EMW customers.[36]

(Emphasis added).

It is clear from this excerpt is that Ms. Messamore admitted in the *Dogwood* case that Evergy West (1) cannot currently meet its customers' energy needs with its own generation in a profitable manner for a significant portion of the time, and (2) this means that Evergy West is in critical need of a hedge against the SPP energy market.

The "hedge" that Ms. Messamore refers to in her testimony from the *Dogwood* case is the "insurance" that the OPC is arguing the Company failed to

[35] EA-2023-0291, Direct Testimony of Kayla Messamore, pg. 12.
[36] *Id.*, pg. 12 - 13.

acquire because it has an FAC with a 95/5 sharing mechanism, thus making Evergy West's actions imprudent. In further support, please consider Ms. Messamore's own words as explication:

> Q: What does it mean to need a hedge?
>
> A: A need for a hedge simply means that you do not have sufficient control or certainty around your future outcomes, based on your specific risk tolerance, and so you want to find some way to improve that control/certainty. As Company Witness Reed describes, insurance is an example of a hedge in that it does come with a cost (insurance premium), but the purpose of it is to give you greater stability and security in your future costs. In general, if you do not end up using your health insurance (e.g., because you did not have any major medical issues), you are better off overall. Would it have been nice to know that you were not going to use the insurance so you could save yourself paying the premium cost? Yes. Would it have been possible for you to know that in advance? No. If something serious had happened, would you have been very glad you had insurance? Yes.[37]

This is identical to what I said earlier regarding how Evergy West would have acted had it not had an FAC sharing mechanism. Because Evergy West has an FAC with a 95/5 sharing mechanism reducing its risk of cost recovery, the Company has decided to act imprudently by not acquiring this necessary insurance (*i.e.* generation necessary to hedge against the SPP energy market prices) <u>for decades</u>.

Q. What impact will Evergy West's acquisition of 22% of the Dogwood combined cycle have on its resource position?

A. **

[37] *Id.*, pg. 14.

**[38] Its acquisition of a portion of Dogwood does not resolve Evergy West's dependency upon other electric utilities for capacity.[39]

Based on the actual generation from June 2021 through November 2022,[40] Evergy West's 22% of the Dogwood plant would have only increased its generation of energy in that same time period by 8%.[41] While the acquisition of a portion of the Dogwood plant is a step in the right direction, Evergy West is still largely dependent upon the energy market to meet its customers' energy needs.

Q. Who is the third Evergy Missouri witness that has provided testimony that supports OPC's position in this case?

A. The third witness is Mr. Darin Ives, Evergy West's Vice President of Regulatory Affairs. Mr. Ives provided direct testimony in case no. EO-2023-0277 that agrees with my position when he stated:

> Market purchases can play an important role in a prudent resource mix, <u>but on their own are not a plan but rather are akin to playing Lotto with customers energy supply</u>.[42]

(Emphasis added).

Mr. Ives is right. Evergy West's decision to rely on the SPP energy market to supply a large portion of its customers' energy needs is indeed equivalent to Evergy West

[38] From workpaper "MOW ECAA Plan – Excel" provided by Evergy West in Case No. EO-2023-0213, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2023 Integrated Resource Plan Annual Update Filing*

[39] Currently Evergy West has capacity contracts with Evergy Metro and Evergy Kansas.

[40] Evergy West's response to OPC data request 2005 in case no. EA-2023-0291.

[41] Total of owned and PPA generation.

[42] EO-2023-0277, *In the Matter of the Eleventh Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Evergy Missouri West, Inc. d/b/a Evergy Missouri West,* Direct testimony of Darrin R. Ives, pg. 14.

playing the lotto with customers' money. This was imprudent, as explained by the OPC's witness Dr. Geoff Marke in his surrebuttal testimony in that same case:

> Every decision commits us to some course of action that, by definition, eliminates acting on other alternatives. Placing a bet on the market means we are doubling-down on luck and we are not committing to some other tangible resource that can generate off-system sales. Luck is not a prudent resource. We can't control luck. Therefore relying on the lottery cannot be considered a reasonable course of action.[43]

Q. What information did you consider when developing your recommended sharing mechanism of 75/25?

A. It is obvious that requiring Evergy West to absorb only five percent of the difference between actual cost incurred and the amount of fuel included in revenue requirement is not enough of an incentive for Evergy West to provide a hedge or insurance against volatile market prices for its customers. To make a determination of a more appropriate incentive mechanism, I reviewed the Commission's *Report and Order* in the case where the Commission first granted Aquila an FAC.[44] Not surprisingly, in this case Aquila asked for a 100 percent pass through of costs to customers. However, the Commission found that after-the-fact prudence reviews were insufficient to assure Aquila would take reasonable steps to keep its fuel and purchased power costs down[45] since Aquila would incur no risk of financial loss if it failed to prudently manage its FAC costs.[46]

[43] EO-2023-0277, Surrebuttal testimony of Dr. Geoff Marke, pg. 9.
[44] ER-2007-0004, *In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P Increasing Electric Rates for the services provided to Customers in the Aquila Networks – MPS and Aquila Networks – L&P Service Areas,* attached as Schedule LMM-D-7.
[45] ER-2007-0004, *Report and Order*, page 54.
[46] ER-2007-0004, *Concurring Opinion of Chairman Jeff Davis,* attached as Schedule LMM-D-8, pages 5-6.

A group of intervenors in the case[47] proposed a 50/50 sharing of costs above those in base rates.[48] The Commission concluded that a 50/50 sharing mechanism did not keep with the legislative intent of Section 386.266.5(1)[49] which requires the FAC to be designed to provide the utility with a sufficient opportunity to earn a fair return on equity. The Commission found that "[w]ith a 95% pass-through, [] Aquila will be protected from extreme fluctuations in fuel and purchased power cost, yet retain a significant 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."[50]

Chairman Jeff Davis further explained in his concurring opinion to the *Report and Order* in ER-2007-0004:[51]

> The other proposals considered by the PSC would have excessively penalized the company for fuel and purchased power costs far beyond its control. This would make it extremely difficult for the company to reinvest in infrastructure and to attract the investment capital necessary to maintain infrastructure and expand generation capacity.

He went on to explain that there was no science in how the Commission determined that 95% of the costs should flow through the FAC when he stated:[52]

> Absent certainty of fuel cost variances, some aspects of rate setting are like rate design in that they are more art that science. Although the parties are to be commended for coming to an agreement on how the process should work, their extreme positions left this commission in the position of having to try [to] develop a FAC mechanism that would be just and reasonable to all parties.

[47] AARP, SIEUA, AG Processing, and Federal Executive Agencies.
[48] Staff recommended an interim energy charge and OPC recommended the Commission approve neither an FAC nor interim energy charge for Aquila.
[49] At the time of the *Report and Order* this was Section 386.266.4(1).
[50] ER-2007-0004, *Report and Order*, page 54.
[51] ER-2007-0004, Concurring Opinion of Chairman Jeff Davis, page 6.
[52] *Id.*, page 7.

He also provided the following reminder to Aquila.[53]

> Aquila should be very mindful that the majority of this commission took a bold step in awarding Aquila a fuel adjustment mechanism. This commission and the General Assembly will be watching. If Aquila fails to adopt a proper hedging strategy, fails to follow its hedging strategy or abuses the discretion given to it by this commission in any other way, this commissioner will not hesitate to modify or reject Aquila's FAC application in a future proceeding.

Q. Has Evergy West taken advantage of the large pass through of FAC costs by investing in and maintaining infrastructure or expanding generation capacity as Chairman Davis expected?

A. No. The only additional infrastructure added by Evergy West since this report and order was a 153 MW portion of Iatan 2, which was under construction prior to Evergy West receiving an FAC, the Crossroads Energy Facility that Evergy West's parent company tried to sell but could not find a buyer, and the June 2024 purchase of less than a quarter ownership of the Dogwood plant.

Q. Has Evergy West adopted a proper hedging strategy?

A. No. It has neither built generation to hedge its position in the SPP energy market nor adopted a proper fuel cost hedging strategy. OPC witness John Riley discusses Evergy West's fuel cost hedging strategy in his direct testimony.

Q. Has Evergy West abused the discretion given it by the Commission in its *Report and Order* in case no. ER-2007-0004?

A. Yes, it has.

[53] *Id*.

Q. What should this Commission take from this Report and Order regarding the sharing mechanism of Evergy West's FAC?

A. First, a large carrot has not induced Evergy West to add generation to hedge the energy market costs for its customers. It was granted an FAC where it would recover over 98% of its FAC costs even if costs were 50% greater than what was included in base rates.[54] Evergy West did not reinvest in infrastructure or expand its generation capacity given this generous sharing mechanism.

Second, the setting of the sharing mechanism is an art. When first setting the 95/5 sharing mechanism, the FAC was new in the State of Missouri. No one was sure how the FAC would work or if a 95/5 sharing was an appropriate mechanism. The Commission realized that prudence reviews alone are inefficient at assuring prudency.

Lastly, the Chairman of the Commission when Evergy West's FAC was first approved under Section 386.266 expected that future Commissions would not hesitate to modify or even reject Evergy West's FAC if it did not adopt a proper hedging strategy or abused the discretion given it by the Commission in its FAC.

Q. How did this order inform your decision to recommend a 75/25 sharing of costs?

A. The 95/5 sharing mechanism that the Commission took a bold step in including in Evergy West's FAC has failed to incent Evergy West to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. It has instead incentivized Evergy West to put more risk on its customers. This is the only incentive mechanism data point available for review and it has shown it is not enough to "improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities" as envisioned by the legislature.[55]

[54] See pages 12 – 13 of the FAC whitepaper attached as Schedule LMM-D-2.
[55] Section 386.266.1.

Having no other data points to analyze, I accepted as a floor for a sharing mechanism the Commission's finding in its case no. ER-2007-0004 *Report and Order* that a 50/50 sharing would not allow sufficient recovery of prudent fuel and purchased power costs.[56] A sharing mechanism that recovers 75% of cost above base rates from customers and allows Evergy West 25% of savings is a reasonable choice that relieves some of the risk from the customers to Evergy West. This is a conservative move that would allow movement in future rate cases to Evergy West's response to this increase in its share of the risk. If Evergy West responds with cost-effective resources that can efficiently meet its customer's load requirements, then its share can decrease. If Evergy West continues with its current policy of not adding cost-effective resources, then its share can increase.

Q. Could the Commission adopt any other sharing mechanism?

A. Yes. A sharing mechanism of 85%/15% or 80%/20% would also send a signal to Evergy West that it needs to consider the risk it is placing on the customers through its resource planning decisions to rely on the SPP energy market. A sharing of 60% /40% would send a stronger message. As past Chairman Davis explained in his Concurring Opinion, the setting of a sharing mechanism is an art, not a science.[57]

Q. Is it your expectation that this stick would be more effective than the carrot previously provided by the Commission?

A. I do not think of this change in the mechanism to be a stick. A stick would be shutting down Evergy West's FAC. A 75/25 sharing mechanism is more of a baby carrot as opposed to the current massive carrot that Evergy West expects despite the current failure of that carrot to properly motivate the Company to undertake adequate resource planning.

[56] ER-2007-0004, *Report and Order*, page 54.
[57] ER-2007-0004, *Concurring Opinion of Chairman Jeff Davis*, page 7.

I do believe that moving the sharing mechanism to 75/25 would signal to Evergy West that this Commission will not tolerate continuous imprudent planning that moves all the risk to Evergy West's customers. It would place Every West on notice that an even smaller carrot or perhaps a stick could be in its future if it does not add cost-effective, efficient generation to its fleet.

Q. Has OPC previously raised concerns regarding Evergy West's resource planning process?

A. Yes. OPC raised its concerns regarding Evergy West's resource plan's increased reliance on energy purchased from the SPP market in at least the following cases:

EO-2017-0230	2017 Annual Resource Plan Update
EO-2017-0232	FAC Prudence Review
EO-2018-0045	Contemporary Resource Planning Issue
ER-2018-0146	General Rate Increase Case
ER-2018-0180	FAC Rate Change Case
EO-2018-0269	Evergy West Triennial Resource Planning Compliance filing
ER-2021-0312	General Rate Increase Case
ER-2022-0130	FAC Rate Change Case
EF-2022-0155	Securitization of Storm Uri Costs
EO-2023-0213	2023 Annual Resource Plan Update
EO-2023-0277	FAC Prudence Review

Q. Why has OPC brought this to the Commission so many times?

A. The Commission's general prudence standard is that the utility's conduct should be judged by asking how, based on information available at that time, a reasonable person would have responded. We presented our concerns with Evergy West in every avenue possible so that a reasonable person would respond to the information provided in a prudent manner.

Q. Would you summarize your recommendation to the Commission regarding the FAC incentive mechanism?

A. I recommend the Commission modify the incentive mechanism in Evergy West's FAC to pass through 75% of the FAC costs incurred above what is included in base rates for recovery from customers. The current FAC sharing mechanism of passing 95% of the difference has not provided an incentive for Evergy West to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities. It does not provide a great enough risk of financial loss for Evergy West to acquire generation to hedge the fuel and purchased power costs for its customers. If anything, the 95/5 sharing mechanism reduces the risk to Evergy West enough that it is comfortable playing the market with its customers' pocketbooks.

Q. To be clear, would your proposed 75/25 sharing mechanism result in Evergy West only recovering 75% of its total incurred FAC costs?

A. No. The sharing mechanism is applied only to the difference between the FAC costs included in base rates and the actual costs incurred. If Evergy West hits that base rate cost exactly it recovers 100% of its incurred cost. If the actual incurred costs are less than what is included in base rates, then Evergy West recovers more than 100% of its FAC costs since it gets to keep 25% of that savings. It is only if the actual costs are greater than what is included in base rates that Evergy West would not recover all of its costs. In this situation, Evergy West would keep all of the revenue included in base rates for FAC costs and bill customers for 75% of the increased costs.

TREATMENT OF CROSSROADS ENERGY CENTER

Q. Would you briefly describe the Crossroads Energy Center?

A. Crossroads Energy Center ("Crossroads") consists of four 75 MW simple-cycle gas-fired combustion turbines ("CTs") located in Clarksdale, Mississippi. Crossroads is the property of the City of Clarksdale, Mississippi. Evergy West neither owns nor leases any part of Crossroads; it has a capital lease on the power generated at Crossroads through 2032. Crossroads is in the service territory of Entergy, Inc. ("Entergy"). Entergy is a member of the Mid-Continental Independent System Operator ("MISO"). Evergy West is a member of SPP. Evergy West has a long-term contract for firm transmission to the SPP. Because there is a firm transmission contract, Crossroads is an SPP accredited capacity resource for Evergy West. The transmission contract ends in March 2029.

The Crossroads facility has a long and storied history.[58] In summary, it was built by Aquila Merchant Services, a non-regulated division of Aquila, Inc. in 2002 with the intent of selling energy into a restructured energy market. In March 2007, the plant was transferred to Aquila, Inc. due to the wind-down of Aquila Merchant operations and Crossroads' inability to effectively dispatch power. Prior to its acquisition by Great Plains Energy ("GPE"), Aquila made at least two attempts to find a buyer for Crossroads but did not get a single bid partially due to transmission constraints. GPE transferred this plant that no other entity would buy to Evergy West after acquiring Aquila.

In Case No. ER-2010-0356, the Commission made the following determinations with regard to Crossroads in its *Report and Order*:

> 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 <u>the fair market value of Crossroads at the time of transfer (August 2008) was $61.8 million</u>. Given the subsequent 32

[58] Details can be found in the Commission's Report and Orders in case nos. ER-2010-0356, pages 77 – 100 and ER-2012-0175, pages 52 – 59. These Report and Orders can be found attached to this testimony as Schedules LMM-D-9 and LMM-D-10 respectively.

> 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.[59]

Emphasis added.

Q. Did Evergy West ask the Commission to reconsider its decision?

A. Yes. In its next general rate increase case, ER-2012-0175, Evergy West asked the Commission to increase its valuation of Crossroads and include Crossroads transmission costs in its revenue requirement and its FAC.

Q. What was the Commission's response to Evergy West's request?

A. The Commission ordered the same valuation of the plant. Its decision regarding the treatment of transmission cost, found on page 59 of its Report and Order, was:

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

Q. What has changed since this order with regards to Crossroads since the Commission issued its order in case no. ER-2012-0175?

A. Evergy West entered into a firm transmission contract with Entergy prior to when Entergy joined MISO. At the time of the Commission order in case no. ER-2010-0356, Evergy West was paying about $5 million a year for transmission. When Entergy joined MISO,[60] Evergy West began paying MISO transmission costs to

[59] Pg. 100.
[60] December 19, 2013.

transport the power to Evergy West. Evergy West paid MISO $15.6 million for firm transmission in 2023.[61]

Q. Should the Commission include Crossroads' transmission cost in revenue requirement and the FAC since it has increased so much?

A. No. The Commission in 2010 and 2013 made the determination that it was imprudent to charge customers $5 million for transmission costs to get electricity from a plant in Mississippi to the Kansas City area. If $5 million was imprudent, spending over three times that amount does not make the decision to acquire a plant over 500 miles away a prudent investment for Evergy West's customers.

Q. Is the special protection scheme that the Commission discussed in its Report and Order in case no. ER-2010-0356 still in effect for Crossroads?

A. Yes. There are two transmission lines serving Crossroads. If one of the lines were to trip, the other one could handle 3 of the 4 turbines at full load. As such, a Special Protection System was installed to ramp one of the turbines down should the second line coming from Crossroads become overloaded.

Q. Does the Crossroads plant provide value to Evergy West's customers?

A. The same value that it did when the Commission issued its orders in case nos. ER-2010-0356 and ER-2012-0175. It provides 300 MW of desperately needed capacity for Evergy West. In 2023, the Crossroads facility generated 208,365 MWh or 4.4% of Evergy West's total generation in 2023.

[61] Evergy West response to OPC data request 8039.

Q. What amount of Crossroads transmission cost did Evergy West include in its revenue requirement in this case?

A. Evergy West's witness Cody VandeVelde, in his workpapers provided in this case, shows a MISO transmission revenue requirement request amount of ** __________ ** In response to OPC data request 8040, Evergy West Senior Regulatory Analyst Ila R. Aspey states that ** __________ ** was included in Evergy West's proposed FAC base calculation for Crossroads transmission costs. Table 7 below shows the actual Crossroads transmission costs incurred, the amount included in revenue requirement request for Crossroads transmission, and the amount of Crossroads transmission that was included in the calculation of the FAC base factor.

Table 7
Crossroad Transmission Cost

2023 Actual Cost of Transmission	$15,593,008
Revenue Requirement Request	** __________ **
FAC Base Factor	** __________ **

Removing the cost of Crossroads transmission would reduce Evergy West requested revenue requirement by ** __________ ** and its FAC base by ** __________ **

Q. Should the same cost be used for the revenue requirement and the FAC base factor?

A. Yes, the amount included in the FAC base factor should be the same as the amounts included in the revenue requirement used to set base rates in the case or there is a mismatch from the start. I discuss the importance of consistency between the amounts used in the FAC base factor calculation and the revenue requirement on pages 13 through 15 of my whitepaper attached as Schedule LMM-D-2.

Q. What is your recommendation regarding the treatment of costs of the Crossroads facility?

A. I recommend the Commission continue the rate base treatment of the Crossroads plant as it ordered in case no. ER-2012-0175 and to <u>not</u> include in revenue requirement or Evergy West's FAC the cost of transmitting electricity from the Crossroads facility in Clarksdale, Mississippi to Evergy West's customers in Missouri.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2024-0189

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena M Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M Mantle

Lena M. Mantle

Subscribed and sworn to me this 27th day of June 2024.

TIFFANY HILDEBRAND
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES AUGUST 8, 2027
COLE COUNTY
COMMISSION #15637121

Tiffany Hildebrand

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2027.

<u>Education and Work Experience Background of</u>

<u>Lena M. Mantle, P.E.</u>

In my position as Senior Analyst for the Office of the Public Counsel ("OPC") I provide analytic and engineering support for the OPC in electric, gas, and water cases before the Commission on behalf of ratepayers. I have worked for the OPC since August, 2014.

Prior to working for the OPC, I worked on the Public Service Commission Staff for 29 years retiring as the Manager of the Energy Unit on December 31, 2012. As the Manager of the Energy Unit, I oversaw and coordinated the activities of five sections: Engineering Analysis, Electric and Gas Tariffs, Natural Gas Safety, Economic Analysis, and Energy Analysis sections. These sections were responsible for providing Staff positions before the Commission on all of the electric and gas cases filed at the Commission. This included reviews of fuel adjustment clause filings, resource planning compliance, gas safety reports, customer complaint reviews, territorial agreement reviews, electric safety incidents and the class cost-of-service and rate design for natural gas and electric utilities.

Prior to being the Manager of the Energy Unit, I was the Supervisor of the Engineering Analysis Section of the Energy Department from August, 2001 through June, 2005. In this position, I supervised engineers in a wide variety of engineering analysis including electric utility fuel and purchased power expense estimation for rate cases, generation plant construction audits, review of territorial agreements, and resolution of customer complaints all the while remaining the lead Staff conducting weather normalization in electric cases.

From the beginning of my employment with the Commission in the Research and Planning Department in August, 1983 through August, 2001, I worked in many areas of electric utility regulation. Initially I worked on electric utility class cost-of-service analysis, fuel modeling and what has since become known as demand-side management. As a member of the Research and Planning Department under the direct supervision of Dr. Michael Proctor, I participated in the development of a leading-edge methodology for weather normalizing hourly class energy for rate design cases. I took the lead in developing personal computer programming of this methodology and applying this methodology to weather-normalize electric usage in numerous electric rate cases. I was also a member of the team that assisted in the development of the Missouri Public Service Commission electronic filing and information system ("EFIS").

I received a Bachelor of Science Degree in Industrial Engineering from the University of Missouri, at Columbia, in May, 1983. I am a registered Professional Engineer in the State of Missouri.

Lists of the cases I have filed testimony as an OPC, the Missouri Public Service Commission rules in which I participated in the development of or revision to, and the cases that I provided testimony in follow.

Office of Public Counsel Case Listing

Case	Filing Type	Issue
EF-2024-0021	Surrebuttal	Compliance Tariff Sheets
EO-2023-0277	Direct, Rebuttal, Surrebuttal	FAC Imprudence
ER-2023-0210	Direct, Surrebuttal	FAC Accumulation Period Costs
EO-2023-0136	Rebuttal	FAC and calculation of MEEIA benefits
ER-2023-0011	Rebuttal	Fuel Adjustment Clause and PISA
EA-2022-0328	Surrebuttal	Certificate of Convenience and Necessity
WR-2022-0303	Direct, Rebuttal	Affiliate Transactions, Revenue Stabilization Mechanism
EF-2022-0155	Rebuttal, Surrebuttal	Resource Planning Prudency
ER-2022-0129 & ER-2022-0130	Direct, Rebuttal, Surrebuttal, True-up Direct & Rebuttal	Fuel Adjustment Clause, Resource Planning
EO-2022-0040 & EO-2022-0193	Rebuttal, Surrebuttal	Resource Planning Prudency
ER-2021-0312	Direct, Rebuttal	Storm costs, Market Price Protection Mechanism, FAC
GR-2021-0241	Direct, Rebuttal, Surrebuttal	Revenue Normalization Adjustment, Customer Bills
ER-2021-0240	Direct, Rebuttal	FAC, Customer Bills
GR-2021-0108	Direct, Rebuttal, Surrebuttal	Weather Normalization Adjustment mechanism, miscellaneous tariff issues
WR-2020-0240	Direct, Rebuttal, Surrebuttal	Normalized customer usage, revenue stabilization mechanism
EO-2020-0262	Direct	FAC Imprudence
ER-2020-0311	Rebuttal	FAC rate change
ER-2019-0374	Direct, Rebuttal, Surrebuttal	Weather Norm Rider, Fuel Adjustment Clause
ER-2019-0355	Direct, Rebuttal	Fuel Adjustment Clause, Unregulated Competition tariff sheet
EO-2019-0067 & EO-2019-0068	Rebuttal	Prudence of GMO steam auxiliary costs and GMO and KCPL's wind PPAs
EA-2019-0010	Rebuttal, Surrebuttal	Energy Market Prices, Customer Protections
GO-2019-0058 & GO-2019-0059	Direct, Rebuttal	Weather
ER-2018-0145 & ER-2018-0146	Direct, Rebuttal, Surrebuttal	Purchased Power, Customer Bills, Crossroads, Resource Planning
EO-2018-0092	Rebuttal, Surrebuttal	OPC Opposition of Request for Approval of Changes to Resource Plan
WR-2017-0285	Direct, Rebuttal, Surrebuttal	Normalized base usage
GR-2017-0215 & GR-2017-0216	Direct, Rebuttal, Surrebuttal	Energy Efficiency and Low-Income Programs
EO-2017-0065	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause Prudence Review
ER-2016-0285	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2016-0179	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause,
ER-2016-0156	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause, Resource Planning
ER-2016-0023	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
WR-2015-0301	Direct, Rebuttal, Surrebuttal	Revenues,

Office of Public Counsel Case Listing

Case	Filing Type	Issue
		Environmental Cost Recovery Mechanism
ER-2014-0370	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0351	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0258	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
EC-2014-0224	Surrebuttal	Policy, Rate Design

Missouri Public Service Commission Rules

20 CSR 4240-3	Filing Requirements for Electric Utilities (various rules)
20 CSR 4240-14	Utility Promotional Practices
20 CSR 4240-18	Safety Standards
20 CSR 4240-20.015	Electric Utility Affiliate Transactions
20 CSR 4240-20.017	HVAC Services Affiliate Transactions
20 CSR 4240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
20 CSR 4240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
20 CSR 4240-22	Electric Utility Resource Planning
20 CSR 4240-80.015	Steam Heating Utility Affiliate Transactions
20 CSR 4240-80.017	HVAC Services Affiliate Transactions

Missouri Public Service Commission Staff Testimony

Case No.	Filing Type	Issue
ER-2012-0175	Rebuttal, Surrebuttal	Resource Planning Capacity Allocation
ER-2012-0166	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EO-2012-0074	Direct/Rebuttal	Fuel Adjustment Clause Prudence
EO-2011-0390	Rebuttal	Resource Planning Fuel Adjustment Clause
ER-2011-0028	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EU-2012-0027	Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2010-0356	Rebuttal, Surrebuttal	Resource Planning Allocation of Iatan 2
EO-2010-0255	Direct/Rebuttal	
ER-2010-0036	Supplemental Direct, Surrebuttal	Fuel Adjustment Clause
ER-2009-0090	Surrebuttal	Capacity Requirements
ER-2008-0318	Surrebuttal	Fuel Adjustment Clause
ER-2008-0093	Rebuttal, Surrebuttal	Fuel Adjustment Clause Low-Income Program
ER-2007-0004	Direct, Surrebuttal	Resource Planning
GR-2007-0003	Direct	Energy Efficiency Program Cost Recovery
ER-2007-0002	Direct	Demand-Side Program Cost Recovery
ER-2006-0315	Supplemental Direct, Rebuttal	Energy Forecast, Demand-Side Programs Low-Income Programs

Case No.	Filing Type	Issue
ER-2006-0314	Rebuttal	Jurisdictional Allocation Factor
EA-2006-0309	Rebuttal, Surrebuttal	Resource Planning
ER-2005-0436	Direct, Rebuttal, Surrebuttal	Low-Income Programs, Energy Efficiency Programs, Resource Planning
EO-2005-0329	Spontaneous	Demand-Side Programs, Resource Planning
EO-2005-0293	Spontaneous	Demand-Side Programs, Resource Planning
ER-2004-0570	Direct, Rebuttal, Surrebuttal	Reliability Indices, Energy Efficiency Programs Wind Research Program
EF-2003-0465	Rebuttal	Resource Planning
ER-2002-424	Direct	Derivation of Normal Weather
EC-2002-1	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-672	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-299	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EM-2000-369	Direct	Load Research
EM-2000-292	Direct	Load Research
EM-97-515	Direct	Normalization of Net System
ER-97-394, et. al.	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System Energy Audit Tariff
EO-94-174	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales Weather Normalization of Net System TES Tariff
ER-95-279	Direct	Normalization of Net System
ET-95-209	Rebuttal, Surrebuttal	New Construction Pilot Program
EO-94-199	Direct	Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-90-251	Rebuttal	Promotional Practices Variance
ER-90-138	Direct	Weather Normalization of Net System
ER-90-101	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-85-128, et. al.	Direct	Demand-Side Update
ER-84-105	Direct	Demand-Side Update

Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper

Lena M. Mantle, P.E.
Senior Analyst
Office of the Public Counsel

Revised June 2024

Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper

Introduction

The purpose of this whitepaper is to provide a general description of the history of electric utility fuel adjustment clauses ("FACs") in Missouri prior to and after the passage of Section 386.266 Revised Missouri Statutes ("RSMo") in 2005[1] and provide an understanding of the functionality of the FACs currently implemented throughout the state of Missouri. This whitepaper is not an exhaustive description of the FAC in Missouri but is intended to provide a basic understanding of the history and application of Section 386.266 in a neutral and unbiased manner.

Recovery of Fuel and Purchased Power Costs Prior to Section 386.266 RSMo

In the 1979 Missouri Supreme Court opinion of *Utility Consumer Council of Missouri, Inc. v. P.S.C*,[2] the Court concluded FAC surcharges were unlawful because they allowed rates to go into effect without considering all relevant factors. The Court warned "to permit such a clause would lead to the erosion of the statutorily-mandated fixed rate system." [3] The Court further explained, "If the legislature wishes to approve automatic adjustment clauses, it can of course do so by amendment of the statutes and set up appropriate statutory checks, safeguards, and mechanisms for public participation."[4]

After this Supreme Court opinion, fuel and purchased power costs for Missouri investor-owned utilities were normalized in general rate proceedings and included in the determination of the utility's revenue requirement from which rates were set. This provided an incentive to the electric utility that, if it managed its fuel and purchased power activities in a manner that allowed it to reliably serve its customers at a cost lower than what was included in its revenue requirement in the last rate case, all savings were retained by the electric utility. If actual fuel costs were greater than the normalized costs included in the revenue requirement, the electric utility absorbed the increased costs. When the electric utility believed that it could no longer absorb the increased costs, the electric utility would ask the Commission for an increase in its rates. This incentive worked well for the Missouri electric utilities and their customers for the

[1] Section 386.266 RSMo. was Truly Agreed To and Finally Passed by the Missouri House of Representatives and Senate on April 27, 2005. Governor Matt Blunt signed this legislation on July 14, 2005.
http://www.senate.mo.gov/05info/BTS_Web/Actions.aspx?SessionType=R&BillID=5755
[2] State ex rel. Utility Consumers Council, Inc. v. P.S.C., 585 S.W.2d 41(MO. 1979).
[3] Id. at 57.
[4] Id.

next twenty-five years. The two largest investor-owned electric utilities that provided electricity to Missouri retail customers, Union Electric Company ("Union Electric") and Kansas City Power & Light Company ("KCPL") went for a period of twenty years without a rate increase – not necessarily because fuel costs were over-estimated in revenue requirement but because their total costs were less than the revenue collected due to a variety of factors.

During this time, the investor-owned utilities built generation to meet their customers' needs. There were no centralized markets for electricity that allowed them to rely on other utilities for electricity to meet their customers' needs. However, if a utility had more generation than its customers needed, the excess capacity and generation were sold to neighboring utilities through long-term (10 to 20 years) contracts. This was the case in Missouri from the mid-1980s through early 2000s. Due to inaccurate forecasts that projected high growth of electricity demand, Union Electric and KCPL built excess generation in the 1970s and 1980s. Capital costs of these plants were included in the customers' rates of these electric utilities. Excess generation and capacity from these utilities and other regional providers that also over-built was sold through long-term contracts on a cost-plus basis to the smaller investor-owned electric utilities in the state. This resulted in minimal rate increase requests for these smaller investor-owned electric utilities and provided revenues to the utilities with excess generation to offset some of the capital costs of the excess generation. Eventually the large utilities' customers load requirements grew and these utilities needed the generation they had built in the 1970's and 1980's to meet their own customers' needs. With this excess generation no longer available, to meet their customers' needs, the smaller electric utilities began to build the least cost generation option at that time - natural-gas fired combustion turbines and combined cycle plants. While these plants were less expensive to build than coal or nuclear plants, the natural gas fuel cost was uncertain and, in the late 1990's and early 2000's, very volatile.

At the end of 2000, after two months of extraordinarily cold weather and continued reports of extreme storage withdrawals, the commodity price of natural gas spiked to nearly $10 per thousand cubic feet ("Mcf") after remaining consistently between $1/Mcf to $3/Mcf since the inception of the unregulated wholesale natural gas markets in the 1980s.[5] These wildly fluctuating natural gas prices had little impact on the total fuel costs of KCPL and Union Electric since most of their customers' needs were met through nuclear and coal generation. However, the fluctuating natural gas prices significantly impacted the smaller electric utilities' fuel and purchased power costs and increased their risk of not recovering through rates a return on their investments. These small utilities turned to the Missouri Legislature to provide for the assurance of the recovery of the fluctuating fuel costs through a rate adjustment mechanism

[5] Missouri Public Service Commission Case No. GW-2001-398, EFIS case GW201398xxx, Item no. 44, Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force, August 29, 2001.

that would allow them to change what they charged customers for fuel and purchased power without a full rate case.

Overview of Section 386.266 RSMo

The provisions of Section 386.266 RSMo, also known as Senate Bill 179 ("SB 179"), took effect on January 1, 2006.[6] This section gives the Missouri Public Service Commission ("Commission"), among other things, the authority to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased power costs, including transportation costs. A FAC is such a mechanism. The statute, in addition to requiring approval from the Commission before implementing a FAC, includes other provisions including some consumer protections. It requires the Commission to approve, modify, or reject FACs only as a part of a general rate case proceeding in which all costs and relevant factors are considered. It allows the Commission to include in a FAC features designed to provide incentives to improve the efficiency and cost-effectiveness of the electric utility's fuel and purchased-power procurement activities. If the Commission approves a FAC for an electric utility, the electric utility must file a general rate case so that all rates are reviewed and reset no later than four years after the effective date of the tariff sheets that implement the FAC. Prudence reviews of the costs included in an FAC are to be conducted at least every eighteen months and true-ups to adjust for over and under recoveries are required at least annually. Amounts charged/refunded to the customers through an FAC are required to be separately disclosed on each customer's bill.

Section 386.266.1, which is the provision that grants the Commission the authority to approve, reject or modify FACs, applies only to investor-owned electric utilities in Missouri. At the time it became effective, there were four investor-owned electric utilities in Missouri – Union Electric, KCPL, Aquila, Inc. ("Aquila"), and the Empire District Electric Company ("Empire"). Union Electric subsequently did business as AmerenUE and is now doing business as Ameren Missouri. Aquila subsequently did business as KCP&L – Greater Missouri Operations Company ("GMO") and is now doing business as Evergy Missouri West ("Evergy West"). KCPL is now doing business as Evergy Missouri Metro ("Evergy Metro"). Empire is now doing business as Liberty.

Development of Commission Rules Regarding FACs

Section 386.266.9 RSMo gives the Commission the authority to promulgate rules to govern the structure, content, and operation of FACs. The Commission is also given the authority to promulgate rules regarding the procedures for the submission, frequency, examination,

[6] Section 386.266.13 RSMo.

hearing, and approval of FACs. Soon after Section 386.266 RSMo went into effect, the Staff of the Public Service Commission ("Staff") began the work of developing rules governing the implementation of this section.

In its development of the initial draft rules, Staff worked diligently with a broad group of stakeholders - including representatives from electric utilities, large customers, AARP, and the Office of the Public Counsel ("OPC") in the development of proposed rules to present to the Commission. Auditors, engineers, economists, and attorneys worked together in over fifteen workshops collaborating to develop specific language to propose rules to the Commission to implement the provisions of Section 386.266 RSMo pertaining to FACs. The Commission opened Case No. EX-2006-0472 on June 15, 2006 with a finding of necessity for rules to establish and implement a FAC and began the formal rulemaking process with the proposed rules developed through the collaborative workshop process. The Commission issued its final orders of rulemaking on September 21, 2006.[7] The final order was published in the December 1, 2006 *Missouri Register* effective January 30, 2007. [8] A revised rule, 20 CSR 4240-20.090 *Fuel and Purchased Power Rate adjustment Mechanism*, became effective January 30, 2019.

Key Provisions of the FAC Rule

Despite concerns that a FAC would contribute to over-earnings by electric utilities by the non-utility parties that participated in developing the proposed rules and those that provided comments in the formal rulemaking process, the resulting FAC rules, and the subsequent revised rule, do not contain an earnings test. In FAC proceedings,[9] the Commission is only required to review the costs and revenues included in the FAC. Decreases in non-FAC expenses and increases in revenues not included in the FAC are not considered by the Commission. However, utilities with a FAC are required by Commission rule to submit quarterly surveillance reports to Staff, OPC, and other parties. These surveillance reports include rate base quantifications, capital quantifications and income statements for the electric utilities as a whole.[10] The information from these reports includes the earnings of the electric utility for the prior quarter and could be used in an over-earnings complaint case.[11]

[7] Missouri Public Service Commission, Case No. EX-2006-0472, EFIS items 27 and 28
[8] http://s1.sos.mo.gov/CMSImages/adrules/moreg/previous/2006/v31n23/v31n23b.pdf
[9] Cases filed to change the FAC rate, review the true-up amount, and prudence reviews of the FAC.
[10] 20 CSR 4240-20.090(6).
[11] However, the Commission, in File no. EC-2014-0223, stated that these surveillance reports alone do not provide a complete or accurate picture of earnings sufficient to reset the utility's rates.

Section 386.266.1 requires adjustments to FAC rates to reflect increases and decreases in prudently incurred costs. Therefore, FAC recoveries are based on historical costs.[12] Before an electric utility can begin billing to recover FAC costs, the costs must be incurred, and any revenues included in the FAC to offset those costs must be received. As required by Section 386.266.5, interest at the utility's short-term debt rate is applied to the net of these costs and revenues and recovered or returned to the ratepayers through the FAC rate.

The rule is not prescriptive regarding the rate design to collect or return FAC costs to customers. However, 20 CSR 4240-20.090(13) does require that FAC rates reflect differences in losses incurred in the delivery of electricity at different voltage levels for different rate classes based on system loss studies that must be conducted at least every four years.

While Section 386.266.1 allows the Commission to include features in an FAC designed to provide the electric utilities with incentives to improve the efficiency and cost-effectiveness of the utilities fuel and purchased-power procurement activities, neither the statute nor the rule is prescriptive regarding what such an incentive feature would look like. The rule allows incentive features to be proposed in rate cases in which an electric utility requests the establishment, continuation, or modification of an FAC.[13] Incentive features can be proposed for the Commission's consideration by any of the parties in rate cases in which the electric utility is proposing the establishment, continuation, or modification of a FAC.

Section 386.266 is silent regarding the inclusion in a FAC of any fuel related type of revenues. The Commission rule does not require the inclusion of fuel related revenues, such as revenues from the sale of energy (off-system sales revenues or OSSR),[14] in a FAC. The rule does require that if a FAC does not include revenues from off-system sales, the FAC must exclude the fuel and purchased power costs incurred to make the off-system sales.[15]

<u>History of Requests for FACs</u>

Empire, now Liberty, was the first electric utility to request cost recovery of fuel costs under Section 386.266 RSMo when it filed Case No. ER-2006-0315 on February 1, 2006. This case was filed while the Commission rules were being drafted. In this case, Empire did not request an FAC. Instead it requested an Energy Cost Rider ("ECR") to recover costs between rate cases. Due to a stipulation Empire had entered into in a prior rate case, the Commission required

[12] 20 CSR 4240-20.090(2)(F).
[13] 20 CSR 4240-20.090(14).
[14] Off-system sales revenues are the revenues from sales of energy by the electric utility above what is needed by the utility's customers.
[15] 20 CSR 4240-20.090(1)(L)1.

Empire to remove from its pleadings and other filings its request and support for an ECR.[16] Prior to Empire's next rate case, Case No. ER-2008-0093 filed on October 1, 2007, the Commission FAC rules had been finalized and were effective. The Commission granted Empire a FAC in its July 30, 2008, *Report and Order* in ER-2008-0093. The Commission has authorized continuation of an FAC with modifications in all general rate cases subsequently filed by Empire.

On July 3, 2006 two of Missouri's investor-owned electric utilities filed general rate increase cases in which they requested a FAC. Union Electric, then doing business as AmerenUE, requested the Commission grant it a FAC in Case No. ER-2007-0002 and Aquila requested a FAC in Case No. ER-2007-0004. While the FAC rules were not final at this time, the Commission had, just eighteen days earlier, sent proposed rules to the Missouri Office of the Secretary of State for publication in the Missouri Register. The Commission's determination of the final FAC rules occurred while these rate cases were pending.

In its May 22, 2007 *Report and Order* in the AmerenUE case ER-2007-0002, the Commission concluded:

> After carefully considering the evidence and arguments of the parties, and balancing the interests of ratepayers and shareholders, the Commission concludes that AmerenUE's fuel and purchased power costs are not volatile enough [to] justify the implementation of a fuel adjustment clause at this time.

AmerenUE filed another general rate increase case on April 4, 2008, again seeking the Commission's approval of a FAC in Case No. ER-2008-0318. In its January 27, 2009 *Report and Order*[17] in this case, the Commission authorized AmerenUE to implement an FAC. The Commission has authorized continuation of a FAC with modifications in all general rate cases subsequently filed by AmerenUE now doing business as Ameren Missouri.

The Commission authorized the first FAC for a Missouri investor-owned electric utility under Section 386.266 in its May 17, 2007 *Report and Order* in Aquila's general rate proceeding in case ER-2007-0004. FAC base rates were approved for each of Aquila's two rate districts, then designated as Aquila Networks-MPS and Aquila Networks-L&P. The actual effective date of Aquila's FAC was delayed when the Commission found that the proposed FAC tariff sheets filed by Aquila were not consistent with its *Report and Order*. Tariff sheets implementing the FAC consistent with the Commission's *Report and Order* were approved on June 29, 2007 effective July 5, 2007. Following this rate case, Great Plains Energy acquired Aquila and renamed it

[16] Case No. ER-2006-0315, EFIS item 57, *Order Clarifying Continued Applicability of the Interim Energy Charge*, effective May 12, 2006.
[17] Case No. ER-2008-0318, EFIS item no. 589, page 70.

GMO. The Commission has authorized the continuation of a FAC with modifications in all general rate cases subsequently filed by GMO, now known as Evergy West. When GMO combined the rates of Aquila Networks-MPS and Aquila Networks-L&P in case ER-2016-0156, a single FAC rate was applicable to all of GMO's customers regardless of which utility previously served the customers.

KCPL, now Evergy Metro, was the last Missouri electric utility to be granted an FAC. At the time that SB 179 was being debated at the Legislature, KCPL was negotiating a regulatory plan that would address financial considerations of KCPL's investment in the Iatan 2 Power Plant and other investments, and the timeliness of the recovery of the costs of these investments. As a part of the *Stipulation and Agreement*[18] in that case, KCPL agreed, among other items, that prior to June 1, 2015, it would not seek to utilize any mechanism authorized in SB 179. Therefore, KCPL did not request a FAC until the general rate case ER-2014-0370 it filed on October 30, 2014. The Commission granted KCPL a FAC in its September 2, 2015, *Report and Order*.[19] Tariff sheets implementing an FAC for KCPL became effective September 29, 2015. The Commission has authorized the continuation of an FAC with modifications in all general rate cases subsequently filed by KCPL.

General Structure of FACs in Missouri

While there are some differences in the details of each electric utility's FAC, the general structure of the FACs of each of the electric utilities is the same. An estimate of the FAC costs and revenues, known as Net Base Energy Cost or NBEC, is identified and included in the revenue requirement used to calculate permanent rates of each electric utility in each general rate case in which the FAC is continued or modified. A base factor or BF is calculated in each general rate proceeding as the NBEC divided by the rate case normalized kilowatt-hours ("kWh"). The base factor multiplied by the actual usage provides the revenue billed in permanent rates for FAC costs.

Even though the rule is not prescriptive regarding the design of the FAC rate, in practice, all of the electric utility's FAC rates are volumetric rates based on estimated customer energy usage of the recovery period. To derive a rate to be charged the customers after FAC costs have been incurred, the difference between the actual costs incurred (actual net energy cost or ANEC) over the accumulation period and the costs already included and billed through the permanent

[18] Case No. EO-2005-0329, EFIS item no. 1.
[19] Case No. ER-2014-0370, EFIS item no. 592, page 30.

rates[20] (NBEC), either positive or negative, is divided by the expected energy use of the utility's customers over the recovery period.

Because the FAC rule requires voltage losses to be taken into account in the FAC, a fuel adjustment rate (FAR) is calculated for each of the voltage levels that the utility provides service at based on loss factors derived in the last rate case. These loss-adjusted FARs are the rates used to bill the FAC to the customers. This FAC rate (or FAR) is recovered or returned to customers over a designated recovery period.

Accumulation and Recovery Periods

An accumulation period is the time over which the electric utility incurs the ANEC. Commission rule allows up to four accumulation periods a year but requires at least one accumulation period a year.[21] The Recovery Period is the time period over which the difference between the accumulation period ANEC and NBEC is billed to the utility's customers. The Recovery Period is limited by Commission rule to twelve months or less.[22]

The accumulation periods and recovery periods for the electric utilities are shown in the table below.

Electric Utility	Accumulation Periods	Recovery Periods
Ameren Missouri	February through May	October through May
	June through September	February through September
	October through January	June through January
Evergy Metro	January through June	October through September
	July through December	April through March
Evergy West	June through November	March through February
	December through May	September through August
Liberty	September through February	June through November
	March through August	December through May

The recovery periods are twice as long as the accumulation periods for Ameren Missouri, Evergy Metro, and Evergy West. The purpose of having recovery periods longer than the

[20] Base factor multiplied by net system input kWh for the accumulation period.
[21] 20 CSR 4240-20.090(1)(A).
[22] 20 CSR 4240-20.090(1)(Y).

accumulation periods is to reduce the FAR and minimize the impact of the change in rates on the customers' bills. Ameren Missouri's accumulation periods are four months and the costs from the four-month accumulation period are billed (recovered or returned) over eight months. The accumulation periods of Evergy Metro and Evergy West are six months while the recovery periods are twelve months. Liberty is the only Missouri electric utility where the recovery period is the same length as the accumulation period - both are six months.

The timing of the recovery periods of Ameren Missouri means that customers see both permanent rates and FAR changes in June and October and then see another FAR rate change, in February. Without alignment of the timing of recovery periods, customers of Ameren Missouri could be impacted by changes in rates up to five times a year – twice in permanent rates (summer and non-summer rates) and three times for the FAC rates.

Similarly, one of the FAC recovery periods for Evergy Metro occurs in October when permanent rates also change from the summer to non-summer rates. One of Liberty's recovery periods begins in the same month that the permanent rates change for summer resulting in rates changing for Liberty's customers only three times a year. The timing of FAC rate changes for Evergy Metro and Liberty results in their customers seeing changes in rates just three times a year.

Price Signal Resulting From FACs

There is a common misconception that FACs provide customers more "accurate" price signals than the permanent rates. There are several reasons this is not true. Timing is essential to provide an accurate price signal. Missouri's FAC is based on historical costs, so customers are not billed the difference in the FAC costs until months after the costs are incurred. For example, fuel costs incurred in January for Evergy Metro are not billed to its customers until the recovery period that begins in October. At the time that a change in fuel costs is seen on the customers' bills, it is no longer an accurate representation of the fuel cost the utility is experiencing at that time.

Another reason that FACs in Missouri do not provide accurate price signals is that the accumulation periods bill costs or return savings to customers aggregated over several months. Increases in FAC costs in one month may be offset by decreases in FAC costs in the next month. In addition, the accumulation periods cross seasons of the year when FAC costs typically vary because the load requirements of the customers vary. For these reasons, the length of the accumulation period mutes any price signal.

Long recovery periods designed to reduce FAC rate volatility to customers also mutes the price signal to customers. For example, for Evergy Metro any increase in costs in January is recovered over the time period of October of that same year through September of the next year. An increase in January is spread out over the twelve months of the recovery period so an increase in January combined with changes for all the months in the accumulation period and then spread over twelve months of estimated usage. This is the price signal that the customer is reacting to – not the actual increase in costs that occurred in January. In addition, the customer would not even be billed for the increase in costs in January until the October billing month. If FAC costs are volatile, the customer may be reacting to an increase in cost in the previous year during a time period when costs are actually decreasing. In this instance, the FAC is sending the wrong price signal to the customer.

For these reasons the design and application of FACs in Missouri do not send accurate price signals to customers.

True-Up of FACs

Section 386.266.5(2) RSMo requires that true-ups of FACs occur at least annually. The purpose of a true-up is to make sure that the electric utility recovers all the costs that it is entitled or all amounts due to the customers are refunded. Section 386.266 requires the true-up amount include interest at the electric utility's short-term interest rate.

A true-up is simply a comparison of the actual FAC costs billed the customers in the recovery period to the difference between the actual FAC costs and NBEC that set that FAR. This difference, either negative or positive, is added as a true-up amount, including interest,[23] to the FAC costs to be billed in the next recovery period. In practice, true-ups occur after the end of each recovery period. Because Evergy Metro, Evergy West, and Liberty have two recovery periods a year, they have two FAC true-ups a year. There are three FAC true-ups a year for Ameren Missouri since it has three recovery periods a year. The Commission rule requires the utility to file its true-up in a separate case from changes to its FAR.[24]

The true-up amount is determined by the FAC billed not the FAC revenues recovered. This is to reduce complexity of how to deal with under-paid bills. While the FAC amount is separately identified on the customer's bill, the customer that only pays a portion of their bill does not designate what portion of the bill they are paying. The unpaid portion of the bill is treated as uncollectible. The rate case treatment for uncollectibles is determined in the rate case and is not dealt with in the FAC.

[23] Section 386.266.5(2).
[24] 20 CSR 4240-20.090(9)(B).

Prudence Reviews

Section 386.266.5(4) requires prudence reviews of the costs in the FAC to occur at least every eighteen (18) months. Since the first FAC under section 386.266 was approved for GMO, the first prudence audit was conducted on GMO's FAC, followed by prudence audits on Empire's, Ameren Missouri's, and Evergy Metro's FACs.[25] Staff conducts FAC prudence audits of Evergy Metro and Evergy West simultaneously since they have the same parent company, Evergy, Inc. The Commission Staff has conducted a prudence audit every eighteen months since those first prudence audits. The Commission has found the utilities imprudent in a few of these cases ordering the return of FAC costs billed to customers with interest.

Incentive Mechanism

Section 386.266.1. allows the Commission to include, in a FAC, incentives to improve the efficiency and cost-effectiveness of the electric utilities' fuel and purchased power procurement. The Commission, for each of the electric utilities, found that allowing the utility to have one hundred percent recovery of its FAC costs through a FAC would act as a disincentive for the utility to control FAC costs. The Commission determined that recovering a share of the difference between the NBEC and ANEC allows the electric utility a sufficient opportunity to earn a fair return on equity while protecting customers by providing an incentive to control costs. The Commission has set that sharing percentage, for all of the electric utilities, to be 95/5, *i.e.* 95% of any increase in FAC costs above the NBEC would be billed to the customers and the electric utility absorbs 5%, while 95% of a decrease in FAC costs below the NBEC would be credited to customers and the electric utility retains 5% of the decrease.[26]

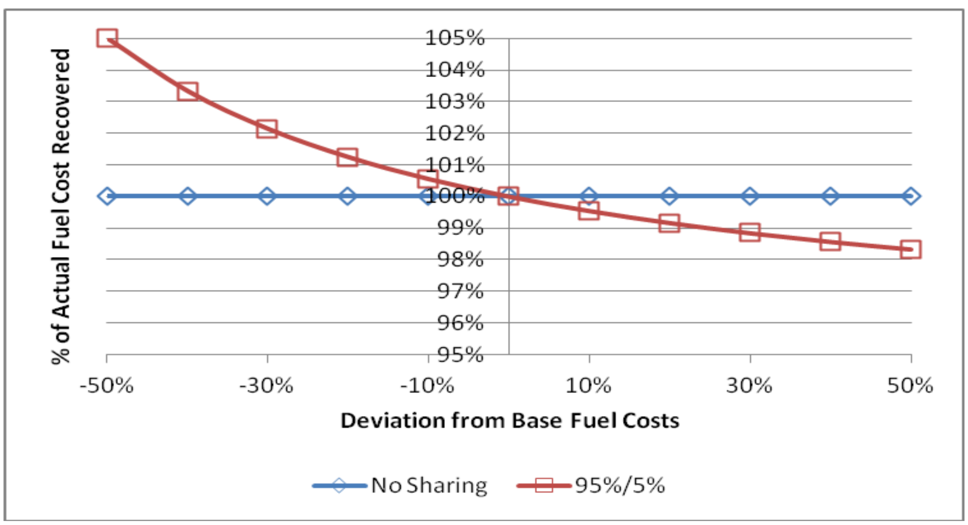
Given this incentive mechanism, the amount to be billed through the FAC is 95% <u>of the difference between the ANEC and the NBEC</u>. The result of this incentive mechanism is that, when costs are above the amounts included in permanent rates, the electric utility recovers <u>almost 100% of its total FAC costs</u>. If FAC costs are below the amounts included in permanent rates, <u>the utility recovers greater than 100% of its FAC costs</u>. The table below shows examples of what occurs when actual costs are greater, equal to, and less than what is in the NBEC.

[25] Case Nos. EO-2009-0115, EO-2010-0084 and EO-2010-0255 for GMO, Empire and Ameren Missouri respectively.
[26] While parties in rate cases have proposed different sharing percentages and/or different incentive mechanisms, the only incentive mechanism implemented has been a 95%/5% sharing of the difference between ANEC and NBEC.

Impact of 95/5 Sharing Mechanism

NBEC	ANEC	Diff	FAC Amt Billed to Customers	Amt Absorbed/ (Retained) by Company	Total billed to Customers	% FAC Costs Billed
$100	$150	$50	$47.50	$2.50	$147.50	98.3%
$100	$110	$10	$9.50	$0.50	$109.50	99.5%
$100	$100	$0	$0	$0	$100.00	100.0%
$100	$90	($10)	($9.50)	($0.50)	$90.50	100.6%
$100	$50	($50)	($47.50)	($2.50)	$52.50	105%

This table shows the incentive mechanism allows the utility to bill its customers for 98.3% of its FAC costs even when its actual costs (ANEC) are 50% higher than what is included in permanent rates, *i.e.* if the actual FAC costs incurred are 50% higher than what was included in the permanent rates (NBEC), the electric utility recovers 98.3% of its actual FAC costs.[27] Likewise, if actual fuel costs are 50% lower than what is included in permanent rates, the utility will recover 105% of its actual FAC costs. If the utility manages to reduce its actual FAC costs any amount below the NBEC, it will recover more than 100% of its FAC costs. This relationship is shown in the graph below.



These relationships hold true regardless of the magnitude of the NBEC.

<u>Importance of Setting the NBEC Correctly</u>

Because Missouri's FACs are based on the difference between a subset of normalized costs and revenues set in a rate case and actual costs and revenues, it is important that the costs and

[27] For a utility to bill only 95% of its actual costs, the actual FAC costs would need to be over 1,000 times greater than the costs included in permanent rates.

revenues included in the base factor used to calculate NBEC are the same as the costs and revenues included in permanent rates. The table below shows three different scenarios. To simplify the example, in these scenarios there is no sharing of the difference between ANEC and NBEC. All of the difference between the ANEC and NBEC is billed or returned to the customers.

Net Base Energy Cost (NBEC)	FAC Costs in Permanent Rates	Actual Net Energy Cost (ANEC)	Billed FAC Costs	Total FAC Costs Billed	Total billed as % of ANEC
Scenario 1 - NBEC Equal FAC Costs in Rates					
$100.00	$100.00	$110.00	$10.00	$110.00	100.00%
$100.00	$100.00	$100.00	$0.00	$100.00	100.00%
$100.00	$100.00	$90.00	-$10.00	$90.00	100.00%
Scenario 2 - NBEC Lower than FAC Costs in Rates					
$100.00	$110.00	$110.00	$10.00	$120.00	109.09%
$100.00	$110.00	$100.00	$0.00	$110.00	110.00%
$100.00	$110.00	$90.00	-$10.00	$100.00	111.11%
Scenario 3 - NBEC Higher than FAC Costs in Rates					
$100.00	$90.00	$110.00	$10.00	$100.00	90.91%
$100.00	$90.00	$100.00	$0.00	$90.00	90.00%
$100.00	$90.00	$90.00	-$10.00	$80.00	88.89%

The first scenario is a correct treatment of NBEC and FAC costs in rates. NBEC is equal to the FAC costs included in permanent rates. In this scenario, when ANEC is higher than NBEC, the total FAC costs billed the customer is the $100 billed in the permanent rates and $10 billed through the FAC for a total of $110. When the ANEC is the same as the NBEC, the customers are billed nothing through the FAC and the utility recovers all of its FAC costs through its permanent rates. Lastly, when the actual costs are less than the NBEC, the customers' bills are reduced and the utility recovers all of its actual fuel costs.

In Scenario 2, the NBEC designated in the FAC is less than the FAC costs in permanent rates. In this scenario, the customers always pay more than the ANEC. Even when ANEC is the same as the FAC costs included in permanent rates, the customer pays for the difference between the ANEC and NBEC because the FAC captures the difference between the two and charges the customers for that amount even though customers have already paid for that amount in the permanent rates. In this scenario, the customers always pay more than the actual FAC costs because the fuel costs included in the permanent rates is greater than the costs used to calculate the NBEC.

In Scenario 3, the NBEC is set higher than the FAC costs included in rates. In this scenario, the electric utility does not collect the actual energy costs because the amount of FAC costs recovered in the permanent rates is less than the NBEC set in the FAC. The amount recovered is the lower FAC costs included in rates and the difference between the higher NBEC and ANEC. In this scenario, the company does not receive the revenues that are intended with an FAC.

These scenarios show the importance of insuring that the FAC costs included in permanent rates are the same as the FAC NBEC. If they are not set correctly, either the customers overpay or the company is not afforded the opportunity to recover its costs as intended.

Conclusion

It is the intent of this whitepaper to give the reader a basic understanding of the history, design, and application of the FAC in Missouri. The FAC in Missouri is continually being refined and defined. The design of the FAC is considered and typically slightly modified in each rate case. Section 386.266.5(3) requires that a utility with a FAC file a general rate case every four years. There have been instances where a utility came in for a general rate case only because it was required to do so by Section 386.266. And there have been many cases that were filed before the general rate case required by Section 386.266.

Questions and suggestions for improvement of this white paper may be directed to its author, Lena Mantle at lena.mantle@opc.mo.gov

Evergy Missouri West/ KCP&L - Greater Missouri Operations Company

	B	D	E	F	G	H	I	J	K
Source	1	1	1	2	D+E	C-E	F/B	C/B	(D+E)/B
	NSI	Total Purchases	Net Generation	PPA Generation (MWh)	Total Generation	Spot Purchase	% Spot Purchase of NSI	% total Purchase of NSI	Total Gen as % of NSI
2017	8,807,485	4,771,123	4,036,362	963,024	4,999,386	3,808,099	43.24%	54.17%	56.76%
2018	9,464,008	6,366,716	3,097,292	1,379,001	4,476,293	4,987,715	52.70%	67.27%	47.30%
2019	9,278,444	6,981,655	2,296,789	2,088,209	4,384,998	4,893,446	52.74%	75.25%	47.26%
2020	9,156,081	7,148,423	2,007,658	2,298,458	4,306,116	4,849,965	52.97%	78.07%	47.03%
2021	9,049,364	6,778,548	2,270,816	2,832,959	5,103,775	3,945,589	43.60%	74.91%	56.40%
2022	9,571,809	7,275,634	2,296,175	3,059,964	5,356,139	4,215,670	44.04%	76.01%	55.96%
2023	8,993,598	7,052,710	1,940,888	2,797,945	4,738,833	4,254,765	47.31%	78.42%	52.69%
	64,320,789					30,955,249	48.13%		

1-Source of Data: Annual Reports filed before the Commission 2018- 2023
2-Source of Data: Annual RES Compliance Report 2018-2023

Resource Planning of a Vertically Integrated Utility in the RTO World

A Whitepaper

Lena M. Mantle, P.E.

Senior Analyst

Office of the Public Counsel

Revised May 30, 2023

The purpose of this whitepaper is to provide an overview of the potential impacts of a regional transmission organization ("RTO") energy market on resource planning of vertically integrated electric utilities. It is not a comprehensive thesis on either resource planning or the RTO energy market. In fact, both electric utility resource planning and RTO energy markets are very complicated with numerous interactions. This whitepaper is a simplistic, yet accurate, high-level view of both. Any views expressed are my own and not necessarily that of the Missouri Office of the Public Counsel.

Resource Planning of a Vertically Integrated Utility in the RTO World

Introduction

Prudent resource planning for a stand-alone vertically integrated electric utility places a priority on reliably meeting its customers' needs at a reasonable cost. When planning that balances reliability and cost is conducted by vertically integrated electric utilities that are members of a regional transmission organization ("RTO"), the resources that best achieve this balance also result in a balancing of load costs charged by the RTO and the revenues provided by the RTO for energy generation.

Prudent resource planning treats the RTO as a supplemental resource and does not cede to the RTO the electric utility's responsibility of providing its customers reliable service at a reasonable rate. There are times when a neighboring utility will have excess energy to sell at a lower price but there is risk in counting on electricity being available at a reasonable cost.

A measure of the adequacy of resource planning of a vertically integrated utility (load serving entity or "LSE") that is a member of a RTO with an energy market is a comparison of the cost of the load charged the utility by the RTO and the revenues the utility receives from the RTO for generation for a vertically integrated utility pays for fuel costs regardless of whether it is a member of a RTO or not. However, this comparison of RTO costs and revenues should not be the objective of resource planning. The objective of resource planning should be providing customers with energy services that are safe, reliable, and efficient at just and reasonable rates.

When revenue for generation is near or greater than the cost of the load, this is an indication that the utility can meet the loads of its customers regardless of whether or not it belongs to an RTO. A revenue much larger than the cost is an indication the utility may have overbuilt. While this is sometime necessary due to the bulkiness of adding generation, this continuously occurring over the long-term is an indication the utility is charging its customers for generation resources that are greater than what they need. Consistently overbuilding results in increased bills for customers to recover the capital costs of the generation and the return on that investment for shareholders. While the excess generation may result in additional RTO revenues, a prudent utility does not gamble the size of customers' bills on beating the RTO market.

Costs consistently greater than the revenues indicates that either the utility is relying on the RTO to meet the load requirements of its customers or there is a lot of transmission congestion in getting electricity to the load. A utility that consistently has market costs greater than revenues can meet the planning capacity requirement of the RTO, either with (1) capacity-only purchased power agreements that do not include the provision of energy to sell into the market, or (2) it maintains its old costly generation resources for the capacity value knowing that the cost of energy generated using these old resources will seldom be "in the money" in the energy market. The customers of a utility that relies on the RTO for energy reduces its risks of building generation but subjects its customers to the volatility and uncertainty of the electric market.

When market and fuel costs skyrocket, the prudent utility, incurs high fuel costs, but it has the resources to generate revenues in the RTO market to offset the load cost. With high market prices, the revenues paid for the utility's generation should more than cover the variable cost of the utility's generation. Utilities without resources, either due to unavailability of its resources or a dependence on market energy instead of its own resources, incur high fuel costs for the limited resources that are bid into the market and, while the market revenues should offset any generation costs, they do not generate enough market revenues to fully offset the load costs. Therefore, load costs above revenues generated is an indication of inadequate resource planning by utilities.

Load Serving Entities and the RTO Energy Market

RTOs have no generation resources. They facilitate the sale and purchase of electricity between its members. They typically have a centralized energy market. Its reliability standard is designed to cost-effectively meet the combined loads of its all its members, not the load of any one member.

Vertically integrated utilities or Load Serving Entities ("LSE") that are members of the RTO, pay the RTO for the hourly[1] load of its customers at a price set by the RTO. This load cost is independent of the energy provided to the market from generation of the LSE in that hour. For example, if a LSE's load is 1,000 mega-Watts ("MW"), it pays the RTO for 1,000 MW regardless of the fact that it, in that same hour, is generating 600 MW, 1,000 MW or 1,200 MW.

Generally, LSEs bid a generation resource into the market at a price to cover the variable cost of generating energy from that resource.[2] If the market price is equal to or greater than the bid provided for a resource (meaning revenue generated will at least cover the variable cost of generating energy from that resource), then the energy from that resource is sold into the market and the fuel cost to generate that energy is charged to the customer.

In Missouri, this charge by the RTO for load is considered purchased power and the cost flows through the fuel adjustment charge ("FAC") to the LSE's customers. Revenue from the sale of energy to the RTO is considered off-system sales revenue which is also included in the FAC in Missouri offsetting fuel and purchased power costs. The difference between the hourly market prices offered for generation and the prices charged for the load is a measure of congestion in the market. The cost to customers can be described with the following simple equation.

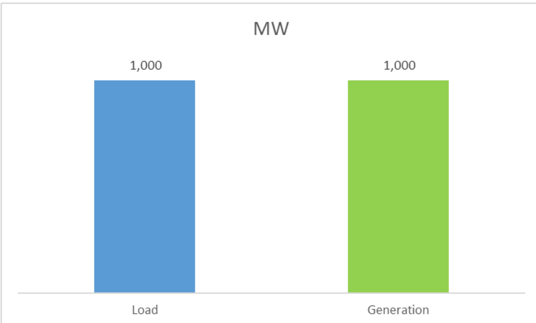
$$\text{Cost to Customers} = \text{Fuel Cost} + \text{Load Cost} - \text{Generation Revenues}$$

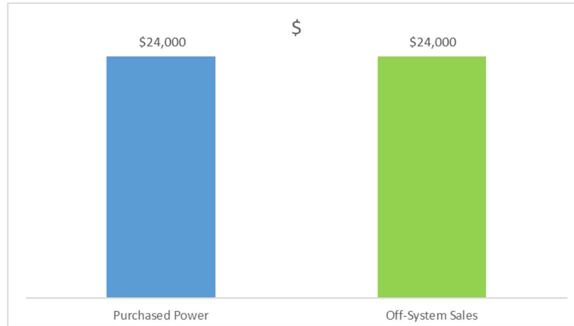
The following three scenarios demonstrate in simplistic terms, how having enough, too little, and more than enough impacts costs to customers. The following assumptions are made to simplify the scenarios.

Congestion	\$0/MWh
Load Charge	\$24/MWh
Revenue for Generation	\$24/MWh
Generation Variable Cost	\$22/MWh

[1] While this is typically done on a 5-minute basis, for this document, the price interval will be considered hourly which is calculated as the average of the 5-minute prices.
[2] Generation can be self-committed meaning it generates regardless of the market price. The assumption in this document is that none of the generation is self-committed.

Scenario 1: Load = Generation



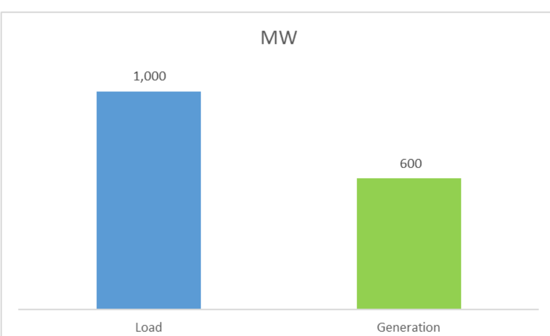


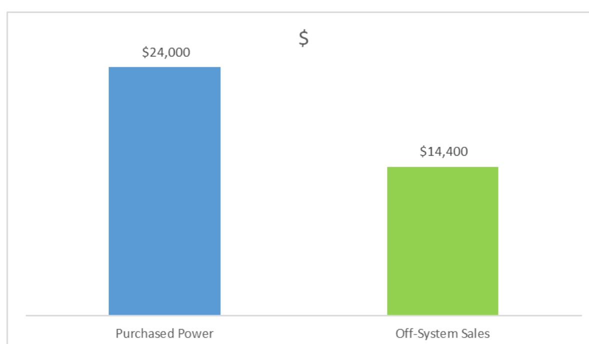
In this scenario, the price of $24/MWh for the load of 1,000 MW (1,000 MW x $24/MWh = $24,000) results in a load or purchased power cost. The RTO is pay $24/MWh for generation so the revenue provided for the 1,000 MW of generation is $24,000 (1,000 MW x $24/MWh = $24,000). When this revenue is netted against the load cost there is no additional cost for the customers for the utility being a member of the RTO. The variable cost (fuel and O&M) for that generation was $22/MWh so the customers would pay $22,000 (1,000 MWh x $22/MWh = $22,000) just as they would have paid if the utility was not a part of the RTO.

The cost to customers for this hour is:

Cost to Customers	=	Fuel Cost	+	Load Cost	-	Generation Revenues
$22,000	=	$22,000	+	$24,000	-	$24,000

Scenario 2: Load > Generation





In this scenario, the price of $24/MWh for the load of 1,000 MW (1,000 MW x $24/MWh = $24,000) results in a load or purchased power cost just as in Scenario 1. The RTO is pay $24/MWh for generation so the revenue provided for the 600 MW of generation is $14,400 (600 MW x $24/MWh = $14,400). The variable cost (fuel and O&M) for that generation was $22/MWh so the customers would pay $13,200 (600 MWh x $22/MWh = $13,200) in variable cost for the generation.

The cost to customers for that hour is:

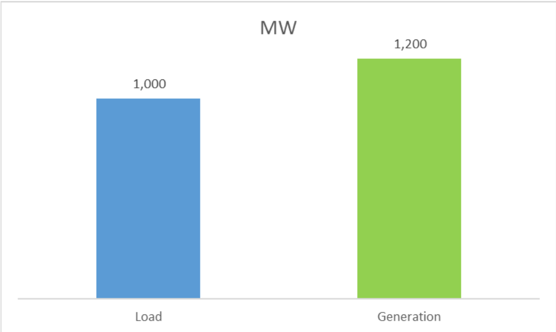
Cost to Customers	=	Fuel Cost	+	Load Cost	-	Generation Revenues
$22,800	=	$13,200	+	$24,000	-	$14,400

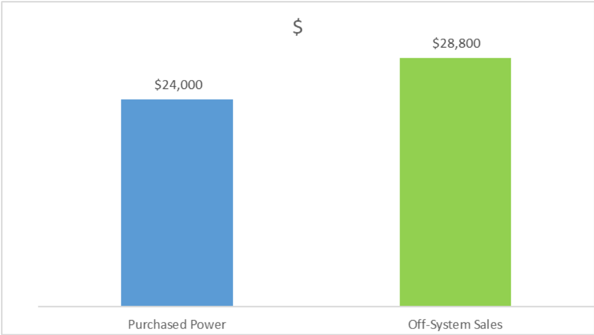
The total cost of not having generation in the market is greater in this scenario than the first scenario. In addition to the increased cost, this LSE relies on the generation of other members of the RTO to meet 400 MW of its customers load requirements.

There are generally two reasons why a LSE buys more from the RTO than it generates. First, it may be because other members have resources that can generate electricity at a cost lower than the LSE. This is a monetary benefit to the LSE's customers because buying from the market is cheaper than the fuel costs of the LSE. There are no reliability concerns for customers since, if the energy cannot be provided by the market, the LSE can generate it, but at a higher cost than purchasing through the market.

The other reason a LSE may buy from the market is that the LSE does not have enough generation resources available that hour regardless of the market price offered to meets its customers' loads thus relying on other utilities to provide energy for its customers. In this instance, the price risk is assumed by customers because the load cost flows through the FAC. There is little to no consequence to the utility because the load cost flows through the FAC.

Scenario 3: Load < Generation





In a RTO market, the generation a LSE can provide to the market is not limited to the load of the utility. In this scenario, the price of $24/MWh for the load of 1,000 MW (1,000 MW x $24/MWh = $24,000) results in a load or purchased power cost of $24,000 just as in Scenario 1 and 2. The RTO is paid $24/MWh for generation so the revenue provided for the 1,200 MW of generation is $28,800 (1,200 MW x $24/MWh = $28,800). The variable cost (fuel and O&M) for that generation was $22/MWh so the customers would pay $26,400 (1,200 MWh x $22/MWh = $26,400) in variable cost for the generation.

The cost to customers for that hour is:

Cost to Customers	=	Fuel Cost	+	Load Cost	-	Generation Revenues
$21,600	=	$26,400	+	$24,000	-	$28,800

In this scenario, the customers have no reliability risk for the utility has more generation than its customers needed.

Summary of Scenarios

	Cost to Customers	Fuel Cost	Load Cost	Generation Revenue
1: Load = Generation	$22,000	$22,000	$24,000	$24,000
2: Load > Generation	$22,800	$13,200	$24,000	$14,400
3: Load < Generation	$21,600	$26,400	$24,000	$28,800

In reality, these scenarios play out for every hour and an LSE may experience all three scenarios in a day. It is rare that a utility supplies the exact amount of energy into the market that it needs. For a well-balanced utility, there will be hours when it supplies more to the market and hours when the market supplies its needs cheaper than if it generated itself.

When looking at these scenarios, a utility could decide that its objective would be to have resources so that the generation would be greater than the load often enough that it would net out any times that load was greater than generation. The fallacy of this objective is that market prices are not static. They fluctuate within every hour. By building to provide energy to the market and not to meet customer loads exposes customers to price risk. If the prices used in the resource planning analysis are accurate, then the customers see the bills estimated in the resource planning process. However, the only thing that is certain about projections is that they will be wrong. This type of planning puts this risk on customers.

Absent in the economics of these three scenarios is the cost of the investments in generation. Resource planning is a balancing of the investment cost for generation and the benefits of both reliability and RTO revenue.

LSE Types

Type 1: Prudent Utility

The resource planning objective of the prudent utility is to meet its customers' loads 8,760 hours of the year at a reasonable cost that minimizes risks and values flexibility across a variety of various futures – some of these futures should include extreme market prices. Its resource planning objective is to be able to provide generation required by its customers every hour at a cost below market prices. To do this all generation resource types are considered taking into account uncertainties and risks of each resource (e.g. reliability of natural gas delivery, intermittent availability of renewables, nuclear waste disposal, residual disposal, environmental restrictions). The flexibility of the resource during extreme events (e.g., extreme natural gas prices, market volatility, extreme weather) is also a consideration when choosing a resource. While a prudent utility can meet its customers' needs on a stand-alone basis, it sees value in being a part of a market where it can sell its generation when it is not needed by its customers and can take advantage of other utilities' diversity of energy resources and loads. This utility does not build to meet the RTO planning reserve margin but meets the RTO planning reserve margin because it builds with a margin that will ensure it is able to meet its customers' needs.

Prudent Utility Response to Scenarios

Scenario 1: Load = Generation

Prudent Utility has the ability to be in this position in every hour of the year. It's rare that it actually occurs but it is possible and planned for.

Scenario 2: Load > Generation

Prudent utility will take energy from the market when the price is below its cost of generating more energy or it has a forced outage at one of its generation plants. Reliability for its customers remains high and customers' bills will be reduced when market prices are lower than generation.

Scenario 3: Load < Generation

Prudent utility could find itself in this position at times when its load is low and its generation is available. It does not build with an objective of being in this situation because that results in higher bills due to the increased investment.

Type 2: Market Player Utility

The Market Player Utility's planning objective is to beat the market. The critical assumption in its resource planning process is forecasted market price assumptions. If actual market prices meet or exceed planning projections, customers' bills are lowered by the market gain; if market prices are lower than projected in the planning, customers' bills are increased. There is little risk to Market Player Utility if it has a FAC, because market risk will be assumed by its customers. Therefore it is not important to the utility whether or not the price assumptions are correct in its analysis.

Reliability of resources to meet customers' energy requirements is not a consideration. Actually customer load is inconsequential to the Market Player Utility. Least-cost in planning is measured by how much revenue the utility forecasts the resources can generate in the market not by how well it meets customers' needs. There is no risk to the utility if forecasted market prices are not realized. Fixed costs plus a return for shareholders are recovered through rates charged customers regardless of whether the resources are in-the-money or not.

Part of the planning process of the Market Player Utility is to make sure that the utility meets RTO planning reserve margin. It is not a natural fallout of the planning process. The RTO is necessary for Market Player Utility's customers to be assured that they have the energy resources they require; the Market Player Utility cedes its responsibility for providing energy to its customers to the RTO.

<u>Response to Scenarios</u>

Scenario 1: Load = Generation

This scenario occurring for a Market Player Utility in any given hour is a coincidence. It is not planned for. Market Player Utility only adds generation to beat the market, not to assure its customers that it can meet their load requirements. It depends on the RTO market to provide energy for its customers.

Scenario 2: Load > Generation

This scenario occurring for a Market Player Utility in any given hour is a coincidence. While it is not necessarily planned for, the Market Player Utility is not concerned when it occurs. The increased cost of purchasing from the market is covered by its customers through the FAC. The Market Player Utility is hoping that Scenario 3 will happen enough to generate revenues to cover costs incurred in this scenario.

Scenario 3: Load < Generation

This is the scenario that the Market Player Utility is hoping happens. If it does not happen enough to cover the increased costs that occurred in other hours, there is no harm to the utility for the load costs are recovered from the customers through the FAC. Its customers pay, not only for the increased cost when this planned for but not realized scenario does not occur, but also the capital cost of and return on additional generation that was built to beat the market.

Type 3: Moocher Utility

Moocher Utility avoids adding owned-generation. It has a short-term view for meeting RTO capacity requirements often relying on other utilities' excess capacity to meet the RTO's requirements through capacity-only contracts and keeps it old, inefficient but fully depreciated generation operable so it is considered capacity for the RTO. The Moocher Utility cedes its responsibility for providing energy to its customers to the RTO relying on other utilities and the RTO energy market to meet its customers' energy requirements.

<u>Response to Scenarios:</u>

Scenario 1: Load = Generation

This scenario occurring for a Moocher Utility in any given hour is an unlikely coincidence. It is most likely to occur when load is low.

Scenario 1: Load > Generation

This is the likely scenario for a Moocher Utility in any given hour. Its reliance on capacity-only contracts to meet the RTO planning reserve margin means that it is not concerned with providing reliable, low cost energy for its customers. Customers' bills can be volatile due to the fluctuations of the cost of market energy. Because the costs flow through to the customer, there is no consequence to Moocher utility of not having capacity without energy.

Scenario 3: Generation > Load

This scenario rarely happens for the Moocher Utility because it meets the RTO capacity requirements with capacity only purchased power agreements.

Conclusion

Electric utility resource planning in the days before RTO markets centered on obtaining resources that would provide reliable energy at a reasonable cost for customers. RTOs offer valuable additional resources for energy and increased reliability to supplement a utility's resources. However, the energy markets have opened another objective for adding resources – playing the market. When owned-resources are added, electric utility shareholders can earn a return on investment with a utility's projected possibility of revenues that, in the long run, are greater than the cost to customers. Earnings to shareholders are a given. A reduction to customers' bills due to market revenues is a possibility. However, even if this possibility does not pan out, shareholders still receive earnings and customers pay the costs.

A utility can rely on RTOs for energy to meet its customers' needs reducing its risk of adding additional generation. However, the objective of a RTO is to cost-effectively meet the combined loads of its members and not the load of any one member.

The interplay between a utility and the RTO it belongs to should be considered in resource planning but a resource portfolio should be built to assure customers safe, reliable, and adequate service at just and reasonable rates. Customers' should not be used as a financing resource for playing the RTO energy markets.

Case No. ER-2024-0189

Schedule LMM-D-5 to

Lena M. Mantle's Direct

Testimony has been

deemed "Confidential"

in its entirety

MARKET EXAMPLES

Tables 5, 6, and 7

Utility	A	B	C
Available Generation			
Plant 1			
MWh	50	50	50
Variable Cost/MWh	$20	$20	$45
Plant 2			
MWh	100	50	
Variable Cost	$40	$45	

Utility	A	B	C
RTO Energy Market			
Market price	$45	$45	$45
Energy Required MWh	100	100	100
Energy Market Cost	$4,500	$4,500	$4,500

Utility	A	B	C
RTO Energy Market			
Market price	$90	$90	$90
Energy Required MWh	100	100	100
Energy Market Cost	$9,000	$9,000	$9,000

Utility	A	B	C
RTO Energy Market			
Market price	$18.00	$18.00	$18.00
Energy Required MWh	100	100	100
Energy Market Cost	$1,800	$1,800	$1,800

Utility	A	B	C
Plant 1			
MWh Produced	50	50	50
Revenue Received	($2,250)	($2,250)	($2,250)
Variable Cost ($/MWh)	$20	$20	$45
Variable Cost Incurred	$1,000	$1,000	$2,250
Plant 2			
MWh Produced	100	50	
Revenue Received	($4,500)	($2,250)	
Variable Cost ($/MWh)	$40	$45	
Variable Cost Incurred	$4,000	$2,250	
Total			
MWh Produced	150	100	50
Revenue Received	($6,750)	($4,500)	($2,250)
Variable Cost Incurred	$5,000	$3,250	$2,250

Utility	A	B	C
Plant 1			
MWh Produced	50	50	50
Revenue Received	($4,500)	($4,500)	($4,500)
Variable Cost ($/MWh)	$20	$20	$45
Variable Cost Incurred	$1,000	$1,000	$2,250
Plant 2			
MWh Produced	100	50	50
Revenue Received	($9,000)	($4,500)	($4,500)
Variable Cost ($/MWh)	$40	$45	$45
Variable Cost Incurred	$4,000	$2,250	$2,250
Total			
MWh Produced	150	100	100
Revenue Received	($13,500)	($9,000)	($9,000)
Variable Cost Incurred	$5,000	$3,250	$4,500

Utility	A	B	C
Plant 1			
MWh Produced	0	0	0
Revenue Received	$0	$0	$0
Variable Cost ($/MWh)	$20	$20	$45
Variable Cost Incurred	$0	$0	$0
Plant 2			
MWh Produced	0	0	0
Revenue Received	$0	$0	$0
Variable Cost ($/MWh)	$40	$45	$0
Variable Cost Incurred	$0	$0	$0
Total			
MWh Produced	0	0	0
Revenue Received	$0	$0	$0
Variable Cost Incurred	$0	$0	$0

Utility	A	B	C
Energy Market Cost	$4,500	$4,500	$4,500
Revenue Received	($6,750)	($4,500)	($2,250)
Variable Cost Incurred	$5,000	$3,250	$2,250
Net Market Cost	$2,750	$3,250	$4,500
Net Market Cost per MWh	$27.50	$32.50	$45.00

Utility	A	B	C
Energy Market Cost	$9,000	$9,000	$9,000
Revenue Received	($13,500)	($9,000)	($9,000)
Variable Cost Incurred	$5,000	$3,250	$4,500
Net Market Cost	$500	$3,250	$4,500
Net Market Cost per MWh	$5.00	$32.50	$45.00

Utility	A	B	C
Energy Market Cost	$1,800	$1,800	$1,800
Revenue Received	$0	$0	$0
Variable Cost Incurred	$0	$0	$0
Net Market Cost	$1,800	$1,800	$1,800
Net Market Cost per MWh	$18.00	$18.00	$18.00

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Tariffs of Aquila, Inc., d/b/a	)	
Aquila Networks – MPS and Aquila Networks – L&P	)	
Increasing Electric Rates for the Services Provided	)	**<u>Case No. ER-2007-0004</u>**
to Customers in the Aquila Networks – MPS and	)	Tariff No. YE-2007-0001
Aquila Networks – L&P Service Areas	)	

REPORT AND ORDER

Issue Date: May 17, 2007

Effective Date: May 27, 2007

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks – MPS and Aquila Networks – L&P Service Areas	)))))	 **Case No. ER-2007-0004** Tariff No. YE-2007-0001

TABLE OF CONTENTS

APPEARANCES

James C. Swearengen, Paul A. Boudreau, and **L. Russell Mitten**, Attorneys at Law, Brydon, Swearengen & England, P.C., 312 East Capitol Avenue, Post Office Box 456, Jefferson City, Missouri 65102-0456, for Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P.

Shelley A. Woods, Assistant Attorney General, Supreme Court Building, Post Office Box 899, Jefferson City, Missouri 65102, for the Missouri Department of Natural Resources.

Stuart W. Conrad and **David L. Woodsmall,** Attorneys at Law, Finnegan, Conrad & Peterson, 1209 Penntower Office Center, 3100 Broadway, Kansas City, Missouri 64111, for the Sedalia Industrial Energy Users Association and AG Processing, Inc.

Capt. Frank Hollifield, AFCESA/ULT, Attorney at Law, 139 Barnes Drive, Ste. 1, Tyndall Air Force Base, Florida 32406, for the Federal Executive Agencies.

John W. Coffman, Attorney at Law, 871 Tuxedo Blvd., St. Louis, Missouri 63119-2044, for the American Association of Retired Persons.

William D. Steinmeier, Attorney at Law, Post Office Box 104595, 2031 Tower Drive, Jefferson City, Missouri, 65102, for the City of St. Joseph, Missouri.

Mark W. Comley, Attorney at Law, Post Office Box 537, 601 Monroe Street, Suite 301, Jefferson City, Missouri, 65102-0537, for the City of Kansas City, Missouri.

Rick D. Chamberlain, Attorney at Law, BEHRENS, TAYLOR, WHEELER & CHAMBERLAIN, 6 N.E. 63rd, Suite 400, Oklahoma City, Oklahoma 73102, for The Commercial Group.

Lewis R. Mills, Jr., Public Counsel, and **Michael F. Dandino**, Deputy Public Counsel, Office of the Public Counsel, Post Office Box 2230, Jefferson City, Missouri 65102, for the Office of the Public Counsel and the public.

Kevin A. Thompson, General Counsel, **Nathan Williams,** Deputy General Counsel, **Dennis L. Frey,** Senior Associate General Counsel, Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

REGULATORY LAW JUDGE: Cherlyn D. Voss

REPORT AND ORDER

I. Background

A. Procedural History

On July 3, 2006, Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P ("Aquila") filed proposed tariff sheets, Tariff File No. YE-2007-0001, designed to implement a general rate increase for retail electric service. The matter was opened and denominated ER-2007-0004. The new rates contained therein were designed to produce additional gross annual electric revenues of $94,500,000 in Aquila's MPS operating division, and $24,400,000 in Aquila's L&P operating division, excluding gross receipts, sales, franchise, and occupational taxes. The proposed increase would result in a 22% and 22.1% increase, respectively, over existing revenues. The tariff sheets proposed an effective date of August 2, 2006.

The Commission issued its Suspension Order and Notice on July 5, 2006, suspending the proposed tariff sheets for 180 days plus six months from the original proposed effective date, that is, until May 31, 2007. In the same order, the Commission directed notice of Aquila's tariff filing be provided to interested parties and the public. The Commission also established July 31 as the deadline for submission of applications to intervene.

The Sedalia Industrial Energy Users Association ("SIEUA"), AG Processing, Inc. ("AG Processing"), the City of St. Joseph, Missouri, the City of Kansas City, Missouri, Union Electric Company, d/b/a AmerenUE ("AmerenUE"), the Missouri Department of Natural Resources ("DNR"), AARP, and the Federal Executive Agencies ("FEA"), submitted timely applications and were allowed to intervene. Subsequently, The Commercial Group and the

County of Jackson, Missouri filed late applications to intervene and were also allowed to intervene.

On August 2, 2006, the Commission established the test year for this case as the 12-month period ending December 31, 2005, adjusted and updated for any known and measurable changes through June 30, 2006. The Commission deferred making a decision as to whether to order any further true-up in this case until the parties were prepared to offer further recommendations. The parties subsequently agreed that no further true-up was needed, and no further true-up was ordered. On August 22, 2006, the Commission established a procedural schedule that included dates for the filing of prepared testimony and set an evidentiary hearing to begin on April 4.

The Commission conducted five local public hearings within Aquila's service territory at which the Commission heard comments from Aquila's customers and the public regarding Aquila's request for a rate increase. Public hearings were held in Lee's Summit on January 22, 2007, in Nevada and Sedalia on January 23, and in St. Joseph on January 24.

The parties prefiled direct, rebuttal and surrebuttal testimony. The evidentiary hearing began on April 4, 2007, and continued through April 12, at the Commission's offices in Jefferson City, Missouri. The Commission heard the testimony of 21 witnesses; 112 exhibits were offered during the hearing, including the pre-filed testimony of the witnesses. Most of those exhibits were admitted, some over objection preserved for appeal, and some of which were admitted after a portion was stricken. The Commission took administrative notice of some of the exhibits not admitted.

II. Discussion

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. [1]

---

[1] In making its Findings of Fact and Conclusions of Law, the Commission is mindful that it is required, after a hearing, to "make a report in writing in respect thereto, which shall state the conclusion of the commission, together with its decision, order or requirement in the premises." Section 386.420.2, RSMo 2000. Because Section 386.420 does not explain what constitutes adequate findings of fact, Missouri courts have turned to Section 536.090, which applies to "every decision and order in a contested case," to fill in the gaps of Section 386.420. *St. ex rel. Laclede Gas Co. v. Pub. Serv. Comm'n of Mo.,* 103 S.W.3d 813, 816 (Mo. App., W.D. 2003); *St. ex rel. Noranda Aluminum, Inc. v. Pub. Serv. Comm'n,* 24 S.W.3d 243, 245 (Mo. App., W.D. 2000). Section 536.090 provides, in pertinent part:

> Every decision and order in a contested case shall be in writing, and . . . the decision . . . shall include or be accompanied by findings of fact and conclusions of law. The findings of fact shall be stated separately from the conclusions of law and shall include a concise statement of the findings on which the agency bases its order.

Missouri courts have not adopted a bright-line standard for determining the adequacy of findings of fact. *Glasnapp v. State Banking Bd.,* 545 S.W.2d 382, 387 (Mo. App. 1976). Nonetheless, the following formulation is often cited:

> The most reasonable and practical standard is to require that the findings of fact be sufficiently definite and certain or specific under the circumstances of the particular case to enable the court to review the decision intelligently and ascertain if the facts afford a reasonable basis for the order without resorting to the evidence. *Id.* (*quoting* 2 Am.Jur.2d Administrative Law § 455, at 268).

Findings of fact are inadequate when they "leave the reviewing court to speculate as to what part of the evidence the [Commission] believed and found to be true and what part it rejected." *St. ex rel. Int'l. Telecharge, Inc. v. Mo. Pub. Serv. Comm'n,* 806 S.W.2d 680, 684 (Mo. App., W.D. 1991) (quoting *St. ex rel. Am. Tel. & Tel. Co. v. Pub. Serv. Comm'n,* 701 S.W.2d 745, 754 (Mo. App., W.D. 1985)). Findings of fact are also inadequate that "provide no insight into how controlling issues were resolved" or that are "completely conclusory." *St. ex rel. Monsanto Co. v. Pub. Serv. Comm'n*, 716 S.W.2d 791, 795 (Mo. banc 1986) (relying on *St. ex rel. Rice v. Pub. Serv. Comm'n,* 359 Mo. 109, 220 S.W.2d 61 (1949)).

A. Jurisdiction

The record shows that Aquila operates generation plants for the purpose of generating electricity for sale at retail. The Commission concludes that Aquila is thus an electrical corporation within the intendments of Section 386.020(15) and a public utility pursuant to Section 386.020(42), RSMo Supp. 2004.[2] The Commission thus has jurisdiction over Aquila's services, activities, and rates pursuant to Sections 386.020(42), 386.250 and Chapter 393.

B. Burden of Proof

Section 393.150.2 provides in part, "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."

C. Ratemaking Standards and Practices

The Commission is vested with the state's police power to set "just and reasonable" rates for public utility services,[3] subject to judicial review of the question of

[2] Unless otherwise specified, all statutory references are to the Revised Statutes of Missouri (RSMo), revision of 2000.

[3] 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.

reasonableness.[4] A "just and reasonable" rate is one that is fair to both the utility and its customers;[5] it is no more than is sufficient to "keep public utility plants in proper repair for effective public service, [and] . . . to insure to the investors a reasonable return upon funds invested."[6] In 1925, the Missouri Supreme Court stated:[7]

> 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.

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.[8] "[T]he dominant thought and purpose of the policy is the protection of the public . . . [and] the protection given the utility is merely incidental."[9] However, the Commission must also afford the utility an opportunity to recover a reasonable return on the assets it

---

[4] *St. ex rel. City of Harrisonville v. Pub. Serv. Comm'n of Missouri*, 291 Mo. 432, 236 S.W. 852 (1922); *City of Fulton v. Pub. Serv. Comm'n*, 275 Mo. 67, 204 S.W. 386 (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).

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

[6] *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).

[7] *Id.*

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

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

has devoted to the public service.[10] "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."[11]

The Commission has exclusive jurisdiction to establish public utility rates,[12] and the rates it sets have the force and effect of law.[13] A public utility has no right to fix its own rates and cannot charge or collect rates that have not been approved by the Commission;[14] neither can a public utility change its rates without first seeking authority from the Commission.[15] 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.[16] Thus, "[r]atemaking is a balancing process."[17]

Ratemaking involves two successive processes.[18] 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

---

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

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

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

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

[14] *Id.*

[15] *Deaconess Manor Ass'n v. Pub. Serv. Comm'n*, 994 S.W.2d 602, 610 (Mo. App., W.D. 1999).

[16] *May Dep't Stores*, *supra,*107 S.W.2d at 50.

[17] *St. ex rel. Union Elec. Co. v. Pub. Serv. Comm'n*, 765 S.W.2d 618, 622 (Mo. App., W.D. 1988).

[18] Missouri recognizes two distinct ratemaking methods: the "file-and-suspend" method and the complaint method. The former is initiated when a utility files a tariff implementing a general rate increase and the second by the filing of a complaint alleging that the subject utility's rates are not just and reasonable. *See Utility Consumers Council*, *supra,* 585 S.W.2d at 48-49; St. ex rel. Jackson County v. Pub. *Serv. Comm'n*, 532 S.W.2d 20, 28-29 (Mo. banc 1975), *cert. denied*, 429 U.S. 822, 50 L.Ed.2d 84, 97 S.Ct. 73 (1976).

investors.[19] 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:[20] (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.[21] The calculation of revenue requirement from these four factors is expressed in the following formula:

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

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.

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.[22]

The Public Service Commission Act vests the Commission with the necessary authority to perform these functions. Section 393.140(4) authorizes the Commission to prescribe uniform methods of accounting for utilities and Section 393.140(8) authorizes the

---

[19] *St. ex rel. Capital City Water Co. v. Missouri Pub. Serv. Comm'n*, 850 S.W.2d 903, 916 n. 1 (Mo. App., W.D. 1993).

[20] In the present case, the test year was established as the twelve months ending December 31, 2005, updated and adjusted for known and measurable changes through June 30, 2006. *In the Matter of the Tariff of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P Increasing Rates for Service Provided to Customers in the Aquila Networks – MPS and Aquila Networks L&P Service Areas,* Case No. ER-2007-0004 (*Order Establishing Test Year and Deferring Decision on a True-up* at 2.)

[21] *Id., citing* Colton, "Excess Capacity: Who Gets the Charge From the Power Plant?," 34 Hastings L.J. 1133, 1134 & 1149-50 (1983).

[22] *See St. ex rel. Union Elec. Co. v. Pub. Serv. Comm'n*, 765 SW2d at 622.

Commission to examine a utility's books and records and, after hearing, to determine the accounting treatment of any particular transaction. In this way, the Commission can determine the utility's prudent operating costs. Section 393.230 authorizes the Commission to value the property of electric utilities operating in Missouri, that is, to determine the rate base.[23] Section 393.240 authorizes the Commission to set depreciation rates and to adjust a utility's depreciation reserve from time-to-time as may be necessary.

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 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.

D. Section 386.266 Authorizations and Standard Pertaining to Fuel and Purchased Power Cost Recovery Mechanisms

Section 386.266.1, the statute that allows the Commission to establish a fuel adjustment clause, provides as follows:

> 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

---

[23] Section 393.135 expressly prohibits the inclusion in electric rates of costs pertaining to property that is not "used and useful."

> 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.

Section 386.266.4, sets out some of the provisions that must be included in a fuel adjustment clause, and subsection 4(1) establishes the standard to be used in evaluating a fuel adjustment clause. Subsection 4 reads as follows:

> The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. **The commission may approve** such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, **provided that it finds that the adjustment mechanism** set forth in the schedules:
>
> (1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;
> (2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the utility's short-term borrowing rate, through subsequent rate adjustments or refunds;
> (3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. …case;
> (4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently that at eighteen-month intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added).

As set out above, Section 386.266.4(1), states that to be approved by the Commission, any mechanism must be reasonably designed to help the company earn its allowed return on equity. The statute expressly allows the Commission to accept, reject or modify the mechanism; however, it does not allow the Commission to impose a different standard of review.

Further, Section, 386.226.7, provides the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed rate of return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Additionally, Subsection 9 of that statute requires the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rules 4 CSR 240-3.161 and 4 CSR 240-20.090, which establish in great detail the procedures for submission, approval, and implementation of a fuel adjustment clause. Finally, Subsection 9 specifically authorizes a utility to apply for a cost recovery mechanism under that section before the Commission had adopted those rules.

Commission Rule 4 CSR 240-20.090(4)(A) requires an electric utility with a fuel adjustment clause "to file one (1) mandatory adjustment to its FAC[24] in each true-up year coinciding with the true-up of its FAC." That section authorizes an electric utility with a fuel adjustment clause "to also file up to three (3) additional adjustments to its FAC within a true-up year. With the timing and number of such additional filings to be determined in the general rate proceeding establishing the FAC and in general rate proceedings thereafter."

Commission Rule 4 CSR 240-20.090(9) requires the rate design of any rate adjustment mechanism ("RAM") requested under 4 CSR 240-20.090 to "reflect differences

---

[24] As used in this Commission Rule, "FAC" is an acronym for fuel adjustment clause.

in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes." That section also requires an electric utility requesting a RAM to have "conducted a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it request its initial RAM." The Commission has authority to grant a waiver of any requirement contained in Commission Rule 4 CSR 240-20.090 pursuant to 4 CSR 240-20.090(15) which states: "Provisions of this rule may be waived by the commission for good cause shown after an opportunity for a hearing."

Commission Rule 4 CSR 240 3.161(2)(P) requires an electric utility requesting to establish a RAM as described in 4 CSR 240-20.090(2) to file, "a proposed schedule and testing plan with written procedures for heat rate tests . . . to determine the base level of efficiency for each of the units." The Commission has authority to grant a waiver of any requirement contained in Commission Rule 4 CSR 240-3.161 pursuant to 4 CSR 240-3.161(16) which states: "Provisions of this rule may be waived by the commission for good cause shown."

Although the term "good cause" is frequently used in the law,[25] the rule does not define it. Therefore, it is appropriate to resort to the dictionary to determine its ordinary meaning.[26] Good cause "generally means a substantial reason amounting in law to a legal excuse for failing to perform an act required by law," or to put it more concisely, a "[l]egally sufficient ground or reason."[27] Similarly, "good cause" has also been judicially defined as a

---

[25] *State v. Davis*, 469 S.W.2d 1, 5 (Mo. 1971).

[26] *See State ex rel. Hall v. Wolf*, 710 S.W.2d 302, 303 (Mo. App. E.D. 1986) (in absence of legislative definition, court used dictionary to ascertain the ordinary meaning of the term "good cause" as used in a Missouri statute); *Davis*, 469 S.W.2d at 4-5 (same).

[27] *Black's Law Dictionary* 692 (6th ed. 1990).

"substantial reason or cause which would cause or justify the ordinary person to neglect one of his [legal] duties."[28] Of course, not just *any* cause or excuse will do. To constitute *good* cause, the reason or legal excuse given "must be real not imaginary, substantial not trifling, and reasonable not whimsical."[29] And some legitimate factual showing is required, not just the mere conclusion of a party or his attorney.[30] Moreover, a finding of good cause "lies largely in the discretion of the officer or court to which the decision is committed" and "depends upon the circumstances of the individual."[31]

E. Authority to Issue an Accounting Authority Order

The Court of Appeals has held that the Commission has the regulatory authority to grant a form of relief to a utility in the form of an accounting technique, an AAO.[32] An AAO allows a utility to defer and capitalize certain expenses until the time it files its next rate case, and it protects the utility from earnings shortfalls and softens the blow which results from extraordinary construction programs.[33]

---

[28] *Graham v. State*, 134 N.W. 249, 250 (Neb. 1912). Missouri appellate courts have also recognized and applied an objective "ordinary person" standard. *See, e.g., Cent. Mo. Paving Co. v. Labor & Indus. Relations Comm'n*, 575 S.W.2d 889, 892 (Mo. App. W.D. 1978) ("[T]he standard by which good cause is measured is one of reasonableness as applied to the average man or woman.") *Id*.

[29] *Belle State Bank v. Indus. Comm'n*, 547 S.W.2d 841, 846 (Mo. App. S.D. 1977). *See also Barclay White Co. v. Unemployment Compensation Bd.*, 50 A.2d 336, 339 (Pa. 1947) (to show good cause, reason given must be real, substantial, and reasonable). *Id*.

[30] *See generally Haynes v. Williams*, 522 S.W.2d 623, 627 (Mo. App. E.D. 1975); *Havrisko v. U.S.*, 68 F.Supp. 771, 772 (E.D.N.Y. 1946); *The Kegums*, 73 F.Supp. 831, 832 (S.D.N.Y. 1947).

[31] *Wilson v. Morris*, 369 S.W.2d 402, 407 (Mo. 1963); Matter of Seiser, 604 S.W.2d 644, 646 (Mo. App. E.D. 1980).

[32] *Missouri Gas Energy v. Public Service Commission State of Missouri*, 978 S.W.2d 434 (Mo. App. 1998).

[33] *Id*.

F. Overview

1. Aquila's Proposed General Rate Increase

As filed, Aquila's proposed tariffs sought additional gross annual Missouri jurisdictional revenue of approximately $94.5 million annually in Aquila's MPS operating division and $24.4 million annually in Aquila's L&P operating division, or a 22% and 22.1% increase respectively. Aquila currently serves approximately 235,763 customers in its MPS service territory and approximately 65,313 customers in its L&P service territory.

2. Aquila's Operations

Based in Kansas City, Missouri, Aquila is an investor-owned utility providing retail electric service to 1 million customers in Missouri, Kansas, Colorado, Iowa and Nebraska. Aquila provides retail electric service to customers in Missouri in and about Kansas City and St. Joseph, Missouri under the names Aquila Networks-MPS and Aquila Networks-L&P, respectively. As of December 31, 2005, Aquila had 204,506 residential electric customers, 28,431 small general service customers, 1,199 large general service customers, 155 large power service customers, and 1,472 lights customers in 235 communities in 34 counties.

3. The Other Parties

Intervenor SIEUA is an unincorporated voluntary association consisting of large commercial and industrial users of natural gas and electricity in and around Sedalia, Missouri.

Intervenor AG Processing, Inc., operates a processing facility in St. Joseph, Missouri, and is a large industrial customer of Aquila.

Intervenor St. Joseph, Missouri, is a municipality of the State of Missouri and its residents and commercial interests are customers of Aquila. St. Joseph is also a large consumer of energy supplied by Aquila.

Intervenor Kansas City, Missouri, is a municipality of the State of Missouri and its residents and commercial interests are customers of Aquila. Kansas City is also a large consumer of energy supplied by Aquila.

Intervenor AmerenUE is a regulated electric and gas utility that operates in Missouri and elsewhere.

Intervenor AARP is a nonprofit, nonpartisan membership organization that advocates for people who are 50 years of age or older. AARP has members in Missouri who receive electric service from Aquila and will be affected by the outcome of this case.

Intervenor the Federal Executive Agencies' members include the United States Department of Defense, the United States Department of Energy, and other Federal Executive Agencies, which have offices, facilities or installations in the service territory of Aquila and which purchase utility service from Aquila.

Intervenor the Commercial Group's members are JCPenney Corporation, Inc., Lowe's Home Centers, Inc., and Wal-Mart Stores East, LP.

Intervenor Jackson County, Missouri is a political subdivision of the State of Missouri and its residents and commercial interests are customers of Aquila. Jackson County is also a large consumer of energy supplied by Aquila.

The Missouri Department of Natural Resources ("DNR") is an executive branch department authorized and established by Chapter 640, RSMo. Sections 640.150 through 640.185 charge the Department with certain responsibilities with respect to energy.

The Public Counsel ("OPC") 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 commission[.]"[34]

The Staff of the Commission traditionally appears as a party in Commission proceedings and is represented by 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.]"[35]

G. The Issues

As required by the procedural schedule, the parties jointly filed a list of issues to be determined by the Commission. The parties also filed prehearing briefs setting out their positions and arguments with respect to each issue. In setting out the issues developed by the parties and the parties' stated positions on those issues, the Commission seeks only to inform the reader of these items. The parties' framing of the issues may not accurately reflect the material issues under the applicable statutes and rules. Those issues, as

[34] Sections 386.700 and 386.710.

[35] Section 386.071.

formulated by the parties, are fully recited at the beginning of the discussion of each issue, and are set forth below.[36]

1. Proposed Fuel Adjustment Clause:

A. Should the Commission authorize Aquila to use a fuel and purchased power recovery mechanism allowed by 4 CSR 240.20.090?
   - i. What standard should the Commission use in determining whether to allow Aquila to use a fuel and purchased power adjustment mechanism?
   - ii. What portion of fuel and purchased power costs should be recovered by a recovery mechanism rather than by base rates?
   - iii. Should a fuel and purchased power adjustment mechanism include recovery of any demand charges?
   - iv. Should a fuel and purchased power adjustment mechanism require definitive production standards for recovery of fuel and purchased power costs via the mechanism?

   a. Proposed Adjustment Clause: If the Commission authorized Aquila to use a fuel adjustment clause, how should it be structured?
      - i. What recovery period should be used in the fuel adjustment clause?
      - ii. What line losses adjustment should be included in determining the fuel cost adjustment?
      - iii. How often should the fuel adjustment clause be adjusted?
      - iv. Should the fuel adjustment require a phase-in (cap) for sharp changes in fuel or purchased power costs?
      - v. What heat rate testing of generation plants should be conducted?

   b. Interim Energy Charge: If the Commission authorizes Aquila to use an interim energy charge, how should it be structured?
      - i. What natural gas costs/prices should be included in the charge?
      - ii. What coal costs/prices should be included in the charge?
      - iii. What purchased power costs/prices should be included in the charge?

[36] Only the issues and sub-issues not resolved by the two unanimous stipulations are shown. The numbering of the issues is unchanged from the original list. The parties' positions on the issues are discussed, to the extent necessary, elsewhere in this order.

iv. Should the interim energy charge be established and true-up on a divisional basis (for MPE and for L&P separately) or on a unified basis (MPS and L&P combined)?
v. Additional items to consider include treatment of off-system sales and hedging program cost/benefits.

As outlined by the parties, this issue appears very complicated. However, there are actually only three primary questions for the Commission to decide:

a. Should the Commission authorize Aquila to use a fuel adjustment mechanism to address its fuel and purchased power costs as provided for under Section 386.266 RSMo?
b. If a fuel adjustment mechanism is appropriate, should the Commission authorize Aquila to implement an interim energy charge or a fuel adjustment clause?
c. How should any authorized interim energy charge or fuel adjustment clause be constructed?

Therefore, this Order will address these three issues, together with their attendant sub-issues that also must be decided, as restated. All of the issues and sub-issues pertaining to the establishment of a fuel adjustment clause are contained within these three restated issues.

As noted earlier in this Report and Order, the rates Aquila will be allowed to charge its customers are based on a determination of the company's revenue requirement. Aquila's revenue requirement is the sum of operating and maintenance expenses, depreciation expenses, taxes, and a reasonable return on the net value of property used and useful in serving its customers.[37] A revenue requirement is based on the costs and income the company experienced during a historical test year. For this case, the test year was established as 12-month period ending December 31, 2005, adjusted and updated for any known and measurable changes through June 30, 2006. The Commission will use the expenses and revenues measured during the test year to predict the expenses the

[37] Parcell Direct, Ex. 221, Page 5, lines 10-14.

company will be allowed to recover in future rates. Expenses that may be incurred in the future generally are not included in the rate calculations.

Under traditional rate-making procedures, at the end of the rate case the Commission establishes the rates an electric utility can charge. Once rates are established, the utility cannot change those rates without filing a new rate case and restarting the review process. However, in 2005, the Missouri legislature passed a law allowing the Commission to establish a mechanism for an electric utility to make periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs.[38] The sort of mechanism envisioned by the statute is generally known as a fuel adjustment clause.

Section 386.266.7 provides that the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed rate of return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Subsection (9) required the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in great detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

[38] Section 386.266, RSMo (2006 Cum. Supp.).

a. Should the Commission authorize Aquila to use a fuel adjustment mechanism to address its fuel and purchased power costs as provided for under Section 386.266 RSMo?

i. Sufficiency of Aquila's Filed Request. In his prefiled direct testimony, Public Counsel witness Ryan Kind indicated he could not locate information required by several sections of 4 CSR 240-3.161(2) in Aquila's fuel adjustment clause filing.[39] Mr. Kind did not identify what specific information he believed was missing from the filing, or what additional information Aquila needed to file to comply with that rule. Instead, Mr. Kind criticized Aquila for failing to include with its fuel adjustment clause filing a guide to the information that was responsive to each of the pertinent filing requirements.[40]

In response to a Public Counsel data request, Aquila provided to all parties a guide identifying the location in Aquila's direct testimony where the information required by each section of the Commission rules is located.[41] Following receipt of that guide, Mr. Kind filed his rebuttal testimony in which he did not indicate that he continued to find Aquila's fuel adjustment clause filing was deficient for failure to comply with any statutory requirement or Commission Rule.[42] Under cross-examination, Mr. Kind again alleged that Aquila's initial fuel adjustment clause filing was deficient in that it failed to comply with 4 CSR 240-3.161(2)(O), (Q) and (R).[43] However, Public Counsel does not argue in either its Prehearing or Posthearing brief that Aquila's fuel adjustment clause filing was, or continues to be, deficient as to any Commission Rule.

---

[39] Kind Direct, Ex. 401, pages 15 - 16.

[40] *Id*.

[41] Williams Rebuttal, Ex. 33, page 8, line 21 to page 9, line 4.

[42] Kind Direct, Ex. 401, pages 15-16.

[43] Tr. pages 901- 902, and pages 927- 928.

In their Post Hearing Brief, SIEUA and AG-P allege Aquila failed to comply with 4 CSR 240-3.161(H) in that its fuel adjustment clause filing lacked a "complete explanation of all costs that shall be considered for recovery" under the proposed fuel adjustment clause.[44]

Findings of Fact: The Commission finds the testimony of Aquila witnesses Dennis Williams and H. Davis Rooney contains all the information required by each of the three provisions challenged by Public Counsel.[45] Further, no witness, aside from Mr. Kind, suggested Aquila's fuel adjustment clause filing failed to comply with any of these three provisions. The Commission finds Aquila's fuel adjustment clause filing complies with 4 CSR 240-3.161(2)(O), (Q) and (R).

While the Commission may not agree that all items Aquila seeks to flow through its proposed fuel adjustment clause are appropriate, the Commission finds Aquila's proposed fuel adjustment clause tariff contains a very thorough explanation of all costs Aquila seeks authority to flow through its proposed fuel adjustment clause. Consequently, Aquila also meets the filing requirements of 4 CSR 240-3.161(H).[46]

Conclusions of Law: Based upon its review of Aquila's fuel adjustment clause filing and the evidence presented in this case, the Commission concludes that Aquila's fuel adjustment clause filing complies with all applicable statutory requirements and Commission Rules, except: 1) 4 CSR 240-20.090(9), which requires line loss factors to be included in any fuel adjustment clause filing and requires a utility to have conducted a line

---

[44] Post Hearing Brief of Sedalia Industrial Energy Users Association and AG Processing, Inc., pages 55 – 56.

[45] Rooney Direct, Ex. 23, page 27, line 1 to page 29, line 14; Williams Direct, Ex. 32, page 3, line 10 to page 11, line 5 and Sch. DRW-1; Williams Rebuttal, Ex. 33, page 8, line 19 to page 9, line 4. See also: 4 CSR 240-3.161(2)(O), (Q) and (R).

[46] Aquila's Proposed electric tariffs, P.S.C. MO. No. 1 Original Sheet Nos. 124 and 125, part of the original tariff filing on July 3, 2006, that resulted in the establishment of this case.

loss study within twenty-four months of making a fuel adjustment clause filing; and 2) 4 CSR 240-3.161(2)(P), which requires an electric utility filing to establish a RAM as described in 4 CSR 240-20.090(2) to file "a proposed schedule and testing plan with written procedures for heat rate tests."

ii. Appropriateness of a Waiver of 4 CSR 240-20.090(9). Section 386.266(9) specifically authorizes an electric utility to apply for a cost recovery mechanism under that section before the Commission had promulgated its rules pertaining to fuel and purchased power cost recovery mechanism. The draft rules under consideration at the time of Aquila's filing made recognition of line losses in the fuel adjustment clause optional;[47] however, the rules as finally adopted made recognition of the line losses mandatory.[48]

The issue of Aquila's failure to include appropriate line loss factors, and what line loss factors Aquila should have included in its fuel adjustment clause filing, were raised and addressed by the parties in prefiled testimony,[49] during the evidentiary hearing,[50] and in prehearing and posthearing briefs. In his direct testimony, SIEUA, AG-P, and FEA witness Maurice Brubaker noted Aquila's failure to include line loss factors in its fuel adjustment clause filing and testified as to what factors should have been used.[51] After reviewing Mr. Brubaker's testimony, Aquila witness Dennis Williams agreed that based upon the

---

[47] July 17, 2006 Missouri Register, Vol. 31, No. 14, page 1078.

[48] Final Order of Rulemaking in Case No. EX-2006-0472 (4 CSR 240-20.090) pages 6-7.

[49] Brubaker Direct (Rate Design), Ex. 501, pages 3-6; Williams Surrebuttal, Ex. 34, page 7.

[50] Tr. pages 623 and 647.

[51] Brubaker Direct (Rate Design), Ex. 501, pages 3-6.

language contained in 4 CSR 240-20.090(9), as ultimately adopted by the Commission, the line loss factors proposed by Mr. Brubaker should be included in Aquila's fuel adjustment clause filing.[52]

The line loss factors proposed by Mr. Brubaker and agreed to by Aquila are based upon Aquila's most recent line loss study, which was completed in 2002. Two parties have objected to using the 2002 line loss factors because they are based upon a line loss study conducted more than twenty-four months before Aquila's fuel adjustment clause filing. However, those two parties, SIEUA and AG-P, are also the very parties whose witness recommended the using the line loss factors from the 2002 study.

In the Stipulation and Agreement as to Certain Issues, Aquila's fuel and purchased power cost was set at approximately $200,000,000 for a test year ending December 2005, updated for known and measurable changes through June 30, 2006. Aquila has experienced an increase in its fuel and purchased power cost of between 13 and 20% annually for each of the last 3 years.[53] Based upon evidence presented to the Commission in this case, there is strong reason to believe this trend will continue.[54] If fuel and purchased power costs increase by 15% annually, absent some type of cost adjustment mechanism, Aquila would under recover its prudently incurred fuel and purchased power costs by approximately $30,000,000 in the 12 months following the conclusion of this case, and as much as $90,000,000 over the next 24 months.[55] This likely

---

[52] Williams Surrebuttal, Ex. 34, page 7.

[53] Tr. page 782

[54] Featherstone Direct, Ex. 206, pages 8-9; Tr. pages 920-922 and 941, Aquila Net, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P 2005 Form 10-K Report.

[55] *Id*.

scenario would result in Aquila losing an unconscionable amount of money where no party was prejudiced by Aquila's failure to comply with a technicality of a Commission rule.

Accordingly, good cause exists to grant Aquila a waiver, as provided for under 4 CSR 240-20.090(15), from the following requirements contained in 4 CSR 240-20.090(9): 1) the requirement to include line loss factors in its original fuel adjustment clause filing, and 2) the requirement to include line loss factors in its fuel adjustment clause that are based upon a line loss study completed within twenty-four months of that fuel adjustment clause filing.

The question then becomes what line loss factors should be included in any fuel adjustment clause mechanism approved by the Commission. No party offered testimony suggesting the line loss factors proposed by Mr. Brubaker and taken from Aquila's 2002 line loss study were inappropriate. The line loss factors recommended by Mr. Brubaker are reasonable and should be included in any cost adjustment mechanism authorized for Aquila.

Findings of Fact: Aquila's failure to include sufficient and appropriate line loss factors was sufficiently addressed in the record, as noted above. The Commission finds Aquila's failure to have conducted a line loss study within twenty-four months of filing a request for a fuel adjustment clause, and its failure to include line loss factors in its original filing were reasonable, given that the draft rule in place when Aquila made that filing did not require line loss factors. Further, the Commission finds no party was prejudiced by Aquila's failure to have conducted a line loss study within twenty-four months of filing a request for a fuel adjustment clause, and its failure to include line loss factors in its original filing. Further, the Commission finds rejecting Aquila's fuel adjustment clause request based upon a marginal filing oversight unconscionable, because, as addressed above, it would likely cause Aquila to lose a significant amount of money. Accordingly, the Commission finds good cause exists to grant Aquila a waiver, as provided for under 4 CSR 240-20.090(15), from the following requirements contained in 4 CSR 240-20.090(9): 1) the requirement to include line loss factors in its original fuel adjustment clause filing, and 2) the requirement to include line loss factors in its fuel adjustment clause that are based upon a line loss study completed within twenty-four months of that fuel adjustment clause filing.

Having reviewed Mr. Brubaker's proposal, the Commission finds the line loss factors recommended by Mr. Brubaker are reasonable and should be included in any cost adjustment mechanism authorized for Aquila.

Conclusions of Law: Although the Commission had not yet adopted final rules governing fuel adjustment clauses when Aquila filed its rate case in July of 2006, Aquila's inclusion of a fuel adjustment clause request under Section 386.266 RSMo (Cum. Supp. 2006)[56] was appropriate. As noted above, Section 386.266(9) specifically permitted such an application prior to the promulgation of final rules. The Commission concludes Aquila's waiver request meets the standards under 4 CSR 240-20.090(15) for good cause and permits it to waive both the requirement to include line loss factors in its original fuel adjustment clause filing, and the requirement to include line loss factors based upon a line loss study completed within twenty-four months of that fuel adjustment clause filing.

---

[56] All references to Section 386.266 are to the 2006 Cumulative Supplement unless otherwise noted.

The Commission concludes the line loss factors recommended by Mr. Brubaker may lawfully be used in any cost adjustment mechanism authorized for Aquila. Aquila is still subject to all other requirements contained in 4 CSR 240-20.090(9).

iii. Appropriateness of a Waiver of 4 CSR 240-3.161(2)(P). Commission Rule 4 CSR 240 3.161(2)(P) requires an electric utility seeking to establish a RAM as described in 4 CSR 240-20.090(2) to file "a proposed schedule and testing plan with written procedures for heat rate tests . . . to determine the base level of efficiency for each of the units." As part of its fuel adjustment clause filing, Aquila included a schedule for heat rate and/or efficiency testing that identified, but did not set out in written detail, testing procedures. Under Aquila's proposal, testing would be conducted in accordance with Southwest Power Pool (SPP) criteria – specifically, Section 12.1 – Electrical Facility Ratings.[57]

Staff witness Michael Taylor testified that Aquila provided Staff with additional details concerning the SPP rating testing procedures in response to a data request.[58] Mr. Taylor further testified that he did not believe the SPP procedures identified by Aquila would satisfy the requirements of the applicable rule, in that they would not yield meaningful conclusions regarding the heat rates and/or efficiency of Aquila's generating plants.[59] Mr. Taylor then suggested several alternate sources for testing procedures.[60] No

---

[57] Rooney Direct, Ex. 24, page 27, lines 3-11.

[58] Taylor Rebuttal, Ex. 227, page 3, line 4 to page 4, line 2.

[59] *Id*. at pages 5-6.

[60] *Id*.

witnesses aside from Aquila witness Mr. Rooney and Staff witness Mr. Taylor provided testimony on this issue.

During the evidentiary hearing Staff and Aquila offered Exhibit 242, which was admitted into evidence. Exhibit 242 set out a proposed resolution to Staff's heat rate and/or efficiency testing concerns that was agreeable to Staff and Aquila (242 Proposal). Under the 242 Proposal, if the Commission authorizes a RAM, Aquila must complete a proposed heat rate and/or efficiency schedule and a proposed testing plan with written procedures as described in 4 CSR 240-3.161(2)(P) that are agreeable to all parties to this case. The 242 Proposal would also require Aquila to have that plan completed no less than sixty days before the effective date of a tariff filing seeking a rate adjustment under a fuel adjustment clause or the filing of its initial application for a true-up an interim energy charge.[61]

SIEUA and AG-P also argue that Aquila's fuel adjustment clause filing should be rejected for failure to comply with 4 CSR 240-3.161(2)(P).[62] Their argument is based solely upon Staff witness Mr. Taylor's analysis of Aquila's filing. In their Post Hearing Brief SIEUA and AG-P decline to address or even acknowledge the 242 Proposal, which alleviated Mr. Taylor's concerns.

Findings of Fact: Having reviewed the arguments and evidence presented by each witness, the Commission finds Aquila made a good faith effort to comply with the requirements of 4 CSR 240-3.161(2)(P). Further, as set out above, the Commission finds Aquila would likely experience significant financial hardship if the Commission rejected its fuel adjustment clause based upon a filing oversight. Accordingly, the Commission finds

[61] Ex. 242.

[62] Post Hearing Brief of Sedalia Industrial Energy Users Association and AG Processing, Inc., pages 54 - 55.

good cause exists to grant Aquila a waiver of that provision, as provided for under 4 CSR 240-3.161(16).

The Commission further finds the 242 Proposal to be reasonable with one exception. The Commission does not believe it is appropriate to require the written procedures to be agreed to by all non-Aquila parties to ER-2007-0004, given that parties who believe a RAM is never appropriate could block adjustments under an approved RAM by opposing even reasonable procedures.

Conclusions of Law: Commission Rule 4 CSR 240 3.161(2)(P) requires an electric utility seeking to establish a RAM as described in 4 CSR 240-20.090(2) to file "a proposed schedule and testing plan with written procedures for heat rate tests . . . to determine the base level of efficiency for each of the units." Accordingly, the Commission finds good cause exists to grant Aquila a waiver of that provision, as provided for under 4 CSR 240-3.161(16).

In light of the concerns noted above, the Commission concludes it is reasonably necessary to require, in connection with the establishment of a rate adjustment mechanism, that Aquila develop a heat rate and/or efficiency testing schedule and plan under the terms set out in Exhibit 242, with the following conditions. First, in the event any party to ER-2007-0004 opposes the written heat rate and/or efficiency testing procedures ultimately proposed by Aquila, Aquila may file a motion with the Commission seeking approval of those procedures. Second, Aquila must have finalized procedures that are either agreed to by the parties, or approved by the Commission, in place no less than sixty days before the effective date listed on the tariff for Aquila's initial fuel adjustment clause adjustment filing.

iv. Determining Whether a Fuel Cost Adjustment Mechanism is Appropriate. Aquila has requested a fuel adjustment clause in this rate case and has modified the details of its proposed fuel adjustment clause several times during the course of this proceeding in response to concerns expressed by various parties. The details of the fuel adjustment clause Aquila asks the Commission to approve are found in the surrebuttal testimony of Dennis R. Williams,[63] as modified by further concessions set out in Aquila's Post Hearing Brief at pages 43 to 47. The fuel adjustment clause Aquila proposes would net 100% of off-system sales revenue against fuel and purchased power costs. In other words, off-system sales revenue increases would offset rising fuel and purchased power costs. The proposed fuel adjustment clause would spread recovery or return of over or under-collections over a subsequent 12-month period, and no more than two to four fuel adjustment clause rate adjustments would be allowed per true-up year. Only fluctuations in actual fuel costs, fuel transportation costs, and purchase power costs would be flowed through the proposed fuel adjustment clause. The fuel adjustment clause would also contain provisions for heat rate testing and line loss factors.

While Section 386.266 allows the Commission to approve a fuel adjustment clause,[64] the statute does not **require** the Commission approve a fuel adjustment clause. Instead, it specifically gives the Commission authority to **accept**, **reject or modify** a proposed fuel adjustment clause after giving an opportunity for a full hearing in a general rate case.[65] The statute does not, however, provide specific guidance on when a fuel

---

[63] D. Williams Surrebuttal, Ex. 34, page 6, line 10 to page 9 line 22, and Sch. DRW-1.

[64] Section 386.266, in effect overturns a 1979 Missouri Supreme Court decision finding the Missouri Commission did not have statutory authority to authorize a fuel adjustment clause for residential customers. *State ex rel. Utility Consumers Council of Mo., Inc.*, 585 S.W.2d, at. 49.

[65] Section 386.266.4, RSMo (Cum. Supp. 2006).

adjustment clause should be approved, other than requiring them to be reasonably designed to allow the utility a reasonable opportunity to earn its allowed return on equity.

While Missouri has not allowed electric utilities to use a fuel adjustment clause since 1979, fuel adjustment clauses are common in other states. In fact, other than Missouri, all but two of the 29 non-restructured states without retail competition allow their electric utilities to apply to recover fuel and purchased power costs through some type of fuel adjustment clause.[66] Therefore, other states' experiences with fuel adjustment clauses can be instructive for this Commission in making its decision whether to grant Aquila's request for a fuel adjustment clause.

Several parties proposed financial standards that a company should have to meet before any cost recovery mechanism would be authorized. Aquila argues that if its fuel adjustment clause filing meets the mechanical filing requirements of Section 386.266 RSMo and Commission Rules 4 CSR 240-20.090 and 4 CSR 240-3.161(2)(A) through (S), it should be approved. As addressed above, the Commission found Aquila's fuel adjustment clause filing complies with all applicable statutory requirements and Commission Rules, except specific provisions of: 1) 4 CSR 240-20.090(9) and 2) 4 CSR 240-3.161(2)(P) from which the Commission herein grants Aquila waivers. However, in making a determination as to the appropriateness of authorizing a cost recovery mechanism, the Commission must weigh many factors, including the standard for review contained in Section 386.266.

---

[66] Tr. p. 818, lines 16 – 23.

As addressed above, in addition to setting out basic requirements for inclusion in any authorized cost adjustment mechanism, Section 386.266.4 sets out the following standard for the Commission to use when evaluating a cost recovery mechanism:

> 4. The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section . . . The commission may approve such rate schedules after considering all relevant factors which may affect the costs or overall rates and charges of the corporation, **provided that it find that the adjustment mechanism set forth in the schedules:**
> **(1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity**. (emphasis added)

Public Counsel Witness Ryan Kind argued a cost recovery mechanism should not be approved absent a showing the company faces a "substantial threat to its financial viability if it did not have a fuel adjustment clause in effect that would recover some or all of the increased costs of fuel and purchased power in between rate cases."[67] Mr. Kind gives no indication what would constitute a sufficient threat. As set out in detail above, the evidence in this case supports a conclusion Aquila will likely under recover tens of millions of dollars without a RAM. The Commission is not sure if that would qualify as a "substantial threat to financial viability" under Mr. Kind's analysis, but it illustrates that Mr. Kind's analysis is unduly burdensome, vague and should be rejected.

Further, the Commission considered and dismissed similar arguments for an earnings threshold for eligibility to use a cost recovery mechanism in the formal rulemaking docket for 4 CSR 240-20.090. Specifically, the Commission found "an earnings threshold for eligibility to use a RAM is contrary to the intent of the legislature, as articulated in

[67] Kind Direct, Ex. 401, page 3, line 17 to page 15, line 3.

SB 179.[68] Therefore, no such eligibility criteria will be included in the rule."[69] Mr. Kind's proposed standard is contrary to the standard for approval contained in Section 386.266.4(1), which requires that for the Commission to approve an adjustment mechanism it must be "reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity."

SIEUA, AG-P and FEA witness Donald Johnstone argued the Commission should not authorize a fuel adjustment clause for a utility absent a showing of "acute need," which he defined as requiring "a substantial financial need must be shown by the utility."[70] Mr. Johnstone further stated that for any fuel adjustment clause "to be approved, there ought to be more than a mere convenience to the utility."[71] Mr. Johnstone further suggested the negative effects on customers must be weighed against the benefit to the company.

The Commission agrees a fuel adjustment clause should not be authorized for the mere "convenience" of a utility. However, Mr. Johnstone's "acute need" standard is too vague to be useful in evaluating a fuel adjustment clause request. Like Public Counsel's "substantial threat to its financial viability" standard, Mr. Johnstone's "acute need" standard is contrary to both the intent of the legislature in passing Section 386.266 RSMo, and the approval standard contained in Subsection 386.266.4(1).

Nancy Brockway, an independent consultant who appeared as a witness for AARP, testified that she served as a Commissioner on the New Hampshire Public Utilities Commission from 1998 to 2003, as a senior staff member of the Maine Public Utilities

---

[68] SB 179 has been codified at Section 386.266 RSMo (Cum. Supp. 2006).

[69] Final Order of Rulemaking, Case No. EX-2006-0472 (September 21, 2006).

[70] Johnstone Rebuttal, Ex. 505, p. 9, lines 12 – 15.

[71] *Id*.

Commission from 1983 to 1986, and as a hearing officer and General Counsel for the then-Massachusetts Department of Public Utilities from 1986 to 1991. Since leaving the New Hampshire Commission in 2003, Ms. Brockway has provided consulting services to many different groups and testified before a wide variety of state, federal and international agencies and groups on a wide variety of issues. Ms. Brockway further testified that as a staff advocate, hearing officer and Commissioner, she participated in numerous fuel adjustment clause proceedings, and has provided testimony on the potential problems associated with a fuel adjustment clause.[72]

Ms. Brockway testified a cost adjustment mechanism should only be used for utility costs that meet the following three qualifications:

1. They represent a significant portion of a utility's costs;
2. they fluctuate significantly; and
3. the costs are outside the utility's control.[73]

Ms. Brockway supported the use of these criteria based upon her experience with fuel adjustment clauses as a former Commissioner, hearing officer and staff advocate.

The qualifications, or criteria, proposed by Ms. Brockway appear to be well accepted in the regulatory community, and are similar to the criteria presented to the Commission in Union Electric Company, d/b/a AmerenUE's pending rate case.[74] Further, while Aquila's witnesses challenged the standards and requirements for fuel adjustment clause approval suggested by other witnesses, they did not challenge the validity of the

---

[72] Brockway Surrebuttal, Ex. 601, page 3, line 28 to page 4, line 9.

[73] Brockway Surrebuttal, Ex. 601, page 4, lines 13 through 27, adopting the Direct Testimony of Ronald Binz, Binz Direct, Ex. 600, page 6, lines 21-25.

[74] See: Case No. ER-2007-0002, Ex. 502, Direct Testimony of Michael L. Brosch, p. 16, lines 3-16.

criteria presented by Ms. Brockway. Rather, Aquila contends its proposed fuel adjustment clause meets those criteria.

Brockway's first criterion is whether fuel and purchased power represent a significant portion of a utility's costs. Fuel and purchased power expense is the largest item of expense Aquila incurs, comprising approximately 46% of the company's total operation and maintenance expense.[75] No party disputed these figures. Clearly, Aquila's fuel and purchased power expenses are substantial and meet the first criterion.

The second criterion described by Brockway is that the costs to be tracked must fluctuate significantly, in other words, they must be volatile. Aquila was able to demonstrate its fuel costs will likely be increasing in coming years. No party challenged Aquila's contention that its fuel costs have increased between 13% and 20% annually for each of the past three years, or that its fuel costs are likely to continue to increase into the future.[76] Further, unlike many companies, Aquila does not have contracts in place to cover the bulk of its future fuel and purchased power needs.[77]

Staff witness Cary Featherstone, who has been a Staff utility auditor for twenty-seven years and has testified in dozens of Commission cases,[78] testified high volatility has characterized the purchased power and natural gas markets in recent years, combined with Aquila's heavy reliance on both purchased power and gas-fired generation, make it very difficult to predict with a reasonable degree of certainty fuel costs for Aquila using either

---

[75] D. Williams Surrebuttal, Ex. 34, page 5, lines 3 – 7.

[76] *Id*. at page 6, lines 3-8.

[77] Tr. p. 656 lines 13-17, Tr. p. 659 lines 13-18, and Ex. 415.

[78] Featherstone Direct, Ex. 206, Schedule CGF 1.

historical or forecasted levels.[79] Aquila's fuel and purchased power expenses have been and are likely to continue to be volatile and meet the second criterion.

The third criterion is whether the costs are outside the utility's control. The cost items that would be tracked in a fuel adjustment clause are coal, coal transportation, natural gas, oil, nuclear fuel, and purchased power. Aquila generates its electricity from natural gas and coal-fired power plants,[80] and also utilizes a large amount of purchased power.[81] The price of natural gas, coal, and railroad freight rates to transport that coal are established by national, and in some cases, international markets. Aquila does not have control over those prices. Similarly, Aquila does not have control over the prices it must pay for purchased power.

When a utility's fuel and purchased power costs are oscillating in that way, the time consuming rate-making process cannot possibly keep up with the swings. Further, rate cases are difficult and expensive endeavors for the Commission and intervening parties, as well as for the utility. As a result, in those circumstances a fuel adjustment clause may be needed to protect both the utility and its ratepayers from inappropriately low or high rates.

Findings of Fact: The Commission finds Public Counsel's criteria of showing a "substantial threat to its financial viability if it did not have a fuel adjustment clause in effect that would recover some or all of the increased costs of fuel and purchased power in between rate cases," unreasonable, unduly burdensome and overly vague.

---

[79] Featherstone Direct, Ex. 206, p. 20, lines 1 – 13.

[80] Neff Direct, Ex. 14, Page 3, Lines 14-15.

[81] Stipulation and Agreement as to Certain Issues, Schedule 3.

The Commission finds that a fuel adjustment clause should not be authorized for the mere "convenience" of a utility, but finds that the higher standard of "acute need" is unreasonable and overly vague.

The Commission finds the criteria proposed by Ms. Brockway to be reasonable. The Commission finds Aquila's proposed fuel adjustment mechanism meets all three criteria, as more fully discussed above.

After carefully considering the evidence and arguments of the parties, balancing the interests of ratepayers and shareholders, based on the evidence presented at this hearing and on the Commission's evaluation of Aquila's situation as it currently exists, the Commission finds a RAM is appropriate to address Aquila's fuel and purchased power costs in this proceeding. The Commission cannot, however, guarantee that Aquila's circumstances will justify its continued appropriateness in any future rate proceeding.

Conclusions of Law: The new statute (section 386.266) allows the Commission to approve a fuel adjustment clause. The statute does not require that the Commission approve a fuel adjustment clause. Instead, it specifically gives the Commission authority to accept, reject or modify a proposed fuel adjustment clause after giving an opportunity for a full hearing in a general rate case. Having considered Aquila's request after hearing, the Commission concludes "that an earnings threshold for eligibility to use a RAM is contrary to the intent of the legislature, as articulated in SB 179."[82] As such, the Commission concludes Aquila has met the requirements of section 386.266, and it would be reasonable and in the public interest to permit Aquila to use an adjustment mechanism.

[82] SB 179 has been codified at Section 386.266 RSMo (Cum. Supp. 2006).

The Commission concludes Public Counsel's proposed standard is vague, unduly burdensome and contrary to the standard for approval contained in Section 386.266.4(1), which requires that for the Commission to approve an adjustment mechanism it must be "reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity." Likewise, the Commission concludes Mr. Johnstone's "acute need" standard to be too vague to be useful and contrary to both the intent of the legislature in passing Section 386.266, and the approval standard contained in Subsection 386.266.4(1).

After carefully considering the evidence and arguments of the parties, and balancing the interests of ratepayers and shareholders, the Commission agrees with Aquila and Staff and concludes that a RAM method is appropriate to address Aquila's fuel and purchased power costs in this proceeding.

b. Should the Commission authorize Aquila to implement an interim energy charge or a fuel adjustment clause?

The Commission must now determine what fuel adjustment mechanism is the proper means by which Aquila should recover its volatile fuel costs. To do so, the Commission must balance the need to afford Aquila relief from extreme volatility in fuel and purchased power costs against the need to preserve a financial incentive for Aquila to control its fuel cost.

Staff argues that an interim energy charge is the most appropriate mechanism for addressing the issue of variable fuel and purchased power costs given the recent and continuing fuel and purchased power price volatility. Staff first argues that, unlike a fuel adjustment clause, an interim energy charge affords customers a period of stability regarding electricity prices during its effective period.[83] Staff witness Cary Featherstone proposed the implementation of an interim energy charge similar to that previously implemented for Aquila following a stipulation and agreement in ER-2004-0034.[84]

To implement such an interim energy charge, the Commission would first establish a base level (or floor) for estimated fuel and purchased power costs that would be included in permanent rates. Then, the Commission would authorize the collection of an additional portion of strictly variable costs up to a forecasted level (the ceiling) via an interim energy charge surcharge based on the kWh usage of Aquila's customers. Mr. Featherstone recommended a floor amount reflect a price of $6.00 per MMBtu for natural gas, $55.00 per MWH for variable purchased power, and $21 per ton for high Btu blend coal.[85] Mr. Featherstone next recommended prices reflected in the ceiling amount be $9.00 per MMBtu of natural gas, $90.00 per MWH of purchased energy, and $40 per ton for high Btu blend coal.[86]

Mr. Featherstone further recommended the effective period for the interim energy charge be two years, with a true-up audit to be conducted at the termination of the interim energy charge.[87] If, upon completion of the true-up audit, Aquila's prudently incurred variable fuel and purchased power costs were within the range defined by the ceiling and floor amounts of the interim energy charge, customers would receive a refund equal to the

---

[83] Tr. page 714, lines 20-23.

[84] Featherstone Direct, Ex. 206, page 11, line 13 to page 33, line 21.

[85] Featherstone Rebuttal, Ex. 207, page 6; and Tr. page 755, line 15 to page 756, line 12.

[86] *Id*.

[87] Tr. page 706, lines 15-17.

amount collected minus the prudently incurred actual costs. Any refund amounts due to customers would be returned with interest.[88]

The Commission agrees with Staff that an interim energy charge would afford customers with a period of rate stability. However, on the date an interim energy charge goes into effect the utility's customers are forced to pay the difference between the floor and ceiling rates as an upfront charge. If the ceiling is set too high the customer will be overpaying for up to two years. If the interim energy charge ceiling is set too low, especially if it is set significantly below actual purchased power costs, a utility will not recover its prudently incurred fuel costs.

The Commission has used the interim energy charge in two recent cases, both with equally poor results. In The Empire District Electric Company's (Empire's) recent rate case, the Commission found Empire's interim energy charge had resulted in an annual under-recovery of prudently-incurred fuel and purchased power costs totaling $26.8 million.[89] Similarly, under Aquila's most recently implemented, and subsequently terminated, interim energy charge, Aquila under-recovered its fuel and purchased power costs by approximately $34 million within approximately 20 months.[90]

Staff next argues an interim energy charge is preferable to a fuel adjustment clause because it provides incentives for a utility to run its plants effectively, and to minimize the cost of its fuel and purchased power, both to avoid incurring costs above the forecast level and to take advantage of the opportunities to drive costs below the base

---

[88] Featherstone Direct, Ex. 206, page 11, line 16 to page 12, line 10; and page 14 lines 30-32.

[89] Report and Order, Case No. ER-2006-0315 (December 21, 2006) pages 44-45.

[90] Tr. page 596, lines 4 through 8.

level.[91] The Commission finds Staff's argument unpersuasive in these circumstances. The Commission finds a fuel adjustment clause better addresses Aquila's current situation, and prudence reviews, including some type of incentive mechanism to encourage Aquila to behave prudently, best allow this Commission to set rates that are both just and reasonable for consumers.

While the Commission agrees with Staff that an interim energy charge can be a useful tool to ease the effect of volatility in the price of purchased power, the Commission does not believe it is a superior method to the fuel adjustment clause given the facts in this case.

Findings of Fact: The Commission finds, although an interim energy charge may afford customers a period of rate stability, the possibility of over or under-recovery of prudently incurred fuel costs, as discussed above, outweighs any rate stability benefit. Accordingly, the Commission finds a fuel adjustment clause is preferable to an interim energy charge, because a fuel adjustment clause allows the utility a greater opportunity to recover its actual, prudently incurred fuel costs.

The Commission finds Staff's argument unpersuasive in these circumstances. The Commission finds a fuel adjustment clause better addresses Aquila's current situation, and prudence reviews, including some type of incentive mechanism to encourage Aquila to behave prudently, best allow this Commission to set rates that are both just and reasonable for consumers.

Conclusions of Law: In this instance, the Commission believes a fuel adjustment clause is preferable to an interim energy charge, because a fuel adjustment

[91] Tr. page 714, lines 20 through 23.

clause allows the utility a greater opportunity to recover its actual, prudently incurred fuel costs. While the Commission agrees with Staff that an interim energy charge can be a useful tool to ease the effect of volatility in the price of purchased power, the Commission does not believe it is a superior method to the fuel adjustment clause given the facts in this case. Further, given the significant under-recovery that resulted from the two most recently approved interim energy charges, the Commission is not certain an interim energy charge would satisfy the approval standard contained in Section 386.266.4(1), in that, an interim energy charge arguably is not reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity. The Commission concludes Aquila should be authorized to implement a fuel adjustment clause in this case.

c. How should the fuel adjustment clause be structured?

The Commission must now consider what form that fuel adjustment clause should take.

i. What costs should be recoverable through the fuel adjustment clause? Aquila originally proposed to recover through its fuel adjustment clause all costs recorded in Federal Energy Regulatory Commission ("FERC") Accounts 501, 509, 547, and 555. In addition to the actual costs of fuel and purchased power, these accounts also included related costs, such as unit train lease, depreciation, and maintenance costs; freeze/dust suppression costs; fuel handling costs; costs associated with fly-ash removal; gas reservation charges; and demand charges for purchased power contracts with terms in excess of one year. After considering objections of various parties, Aquila has agreed these costs will be recovered exclusively through base rates.[92] Aquila continues to believe, however, that hedging costs and demand charges related to purchased power contracts with terms of one year or less should be recovered through the fuel adjustment clause.[93]

Staff witness Cary Featherstone argues only variable fuel and purchased power costs, including variable transportation costs, should be included in a fuel adjustment clause.[94] Specifically, Mr. Featherstone contends it is inappropriate to include demand charges for any capacity contracts, regardless of their duration, for two reasons. First, Mr. Featherstone points to the fact that demand charges are fixed costs to reserve capacity, and as such are more like plant investment cost than fuel or purchased power cost. Second, Staff opposes Aquila's use of short-term contracts to meet its growing capacity needs. Staff argues that allowing Aquila to pass on this type of cost would allow Aquila to meet its growing load requirements through short-term capacity, thus creating another disincentive for it to build generating units and placing all the risk of future fuel and purchased power cost increases on its customers.[95] Mr. Featherstone's analysis is persuasive.

Findings of Fact: The Commission finds a reasonable fuel adjustment clause should be straightforward and simple to administer, retain some incentive for company efficiency, and be readily auditable and verifiable through expedited regulatory review. The Commission can find no probative evidence in the record to support a finding that hedging costs or demand charges related to purchased power contracts with terms of one year or

---

[92] Post-Hearing Brief of Aquila, Inc., pages 43 through 44.

[93] *Id*. at page 44.

[94] Featherstone Rebuttal, Ex. 207, page 8, lines 10 through 20.

[95] Tr. page 707, line 25 to page 708, line 17.

less should be recovered in a different manner than purchased power contracts with longer terms. The Commission agrees with Staff, and finds that demand charges are fixed costs to reserve capacity, and as such are more like plant investment cost than fuel or purchased power cost. This is the case irrespective of the length of the purchased power contract. Further, if demand charges on short term contracts are allowed to flow through the fuel adjustment clause, Aquila would be encouraged to forgo entering long term contracts in favor of short term contracts.

Conclusions of Law: The Commission concludes it would be improper to allow Aquila to flow hedging costs or demand costs associated with any purchased power contract through its fuel adjustment clause. The Commission concludes Aquila will only be allowed to flow variable fuel and purchased power costs, including variable transportation costs, through its fuel adjustment clause.

ii. What recovery period should be used? Aquila witness Dennis Williams originally proposed four, quarterly recovery periods. However, faced with opposition from all parties, Mr. Williams changed his position on this issue and stated that the company would agree to the single, annual recovery period proposed by Industrials' witness Mr. Johnstone.[96] No party opposed the use of a single recovery period.

Findings of Fact: The Commission finds a single recovery period is appropriate in that it would benefit Aquila's rate payers by mitigating the effect of seasonal variations in fuel and purchased power costs.[97]

---

[96] D. Williams Direct, Ex. 32, pages 3-5; D. William Surrebuttal, Ex. 34, pages 6-7; and Aquila's Post Hearing Brief, page. 43.

[97] Johnstone Rebuttal, Ex. 505, page 22.

Conclusions of Law: The Commission concludes a single annual recovery period is reasonable and lawful under section 386.266.

iii. What line loss adjustments should be included? Although the draft rules under consideration at the time of the company's filing made recognition of line losses in a fuel adjustment clause optional, 4 CSR 240-20.090 (the Commission's Fuel Adjustment Clause Rule), as finally adopted, makes recognition of line losses mandatory. Aquila's original proposed fuel adjustment clause assumed every customer class had the same line losses and charged every customer on the system the same average loss factor.[98] It is inappropriate to use a single loss factor for all customers, because line losses vary depending upon the facilities used to supply customer needs.[99] To conform to the Commission's Fuel Adjustment Clause Rule and appropriately account for variances in line losses, these differences in line loss factors must be recognized in the fuel adjustment clause.[100]

SIEUA, AG-P and FEA expert witness Maurice Brubaker included a table of "Losses and Loss Multipliers," detailing the line loss factors he recommended be included in any fuel adjustment clause ordered in this case.[101] After considering his recommendation and proposed factors, Aquila recommended his proposal be adopted by the Commission as part of any fuel adjustment clause it approves.[102] No other party took a position on this issue.

---

[98] Brubaker Direct, Ex. 501, page 3, lines 11-17.

[99] *Id*. page 3, line 18 to page 4, line 2.

[100] *Id*.

[101] Id. at page 4

[102] Aquila's Post Hearing Brief, page 44.

Findings of Fact: The Commission finds the line loss factors proposed by Mr. Brubaker and supported by Aquila are appropriate and should be included in the fuel adjustment clause.

Conclusions of Law: The Commission concludes line loss factors must be recognized in the fuel adjustment clause. The Commission further concludes line loss factors proposed by Mr. Brubaker conform to the requirements of the rule.

iv. What heat rate testing of generation plants should be conducted? As addressed in detail above at pages 27 to 29 under the heading, "Appropriateness of a Waiver of 4 CSR 240-3.161(2)(P)," the Commission finds Aquila should be: 1) granted a waiver of Commission Rule 4 CSR 240-3.161(2)(P), and 2) required to have finalized procedures for heat rate and/or efficiency testing that are either agreed to by the parties, or approved by the Commission, in place no less than sixty days before the effective date listed on the tariff for Aquila's initial fuel adjustment clause adjustment filing.

Findings of Fact: The Commission finds the 242 Proposal to be reasonable with one exception. The Commission does not believe it is appropriate to require the written procedures to be agreed to by all non-Aquila parties to ER-2007-0004, given that parties who believe a RAM is never appropriate could block adjustments under an approved RAM by opposing even reasonable procedures.

Conclusions of Law: As addressed in detail above at pages 27 to 29 under the heading, "Appropriateness of a Waiver of 4 CSR 240-3.161(2)(P), the Commission concludes it is reasonably necessary to require, in connection with the establishment of a rate adjustment mechanism, that Aquila develop a heat rate and/or efficiency testing schedule and plan under the terms set out in Exhibit 242, with the following conditions. First, in the event any party to ER-2007-0004 opposes the written heat rate and/or efficiency testing procedures ultimately proposed by Aquila, Aquila may file a motion with the Commission seeking approval of those procedures. Second, Aquila must have finalized procedures that are either agreed to by the parties, or approved by the Commission, in place no less than sixty days before the effective date listed on the tariff for Aquila's initial fuel adjustment clause adjustment filing.

v. How often should the fuel rate be adjusted? Originally Aquila proposed quarterly adjustments. However, in its Post Hearing Brief, Aquila advised the Commission that it did not oppose semi-annual adjustments.[103] Aquila's revised position is in agreement with SIEUA, AG-P and FEA witness Donald Johnstone, who proposed that any fuel adjustment clause authorized for Aquila should include two adjustment periods per year to decrease the impact of seasonal variations in both customer usage patterns and fuel and purchased power costs.[104]

Only Public Counsel witness Russell Trippensee suggested Aquila should only be allowed to adjust its fuel adjustment clause once per year.[105] Mr. Trippensee argued annual adjustments would decrease the impact of seasonal variations in both customer usage patterns and fuel and purchased power costs.[106] However, no party, including Public

---

[103] Post-Hearing Brief of Aquila, Inc., page 44-45.

[104] Johnstone Rebuttal, Ex. 505, page 22.

[105] Trippensee Rebuttal, Ex. 402, pages 4-8.

[106] *Id*.

Counsel, recommended the inclusion of a single adjustment period in either its prehearing or posthearing brief.

Aquila witness Dennis Williams testified that a single adjustment period would not be reasonable for three reasons. First, annual adjustments could result in rate shock to customers given the recent trends toward large annual increases in fuel and purchased power costs. Second, there would be carrying charges associated with delayed recovery. Third, annual adjustments are inconsistent with the objective of Section 386.266 RSMo to allow full and timely recovery of prudently-incurred fuel and purchased power costs.[107]

Findings of Fact: The Commission finds Mr. Williams' testimony on the issue more persuasive, and further finds two adjustments per year will adequately decrease the impact of seasonal variations in both customer usage patterns and fuel and purchased power costs. Accordingly, the Commission finds Aquila's fuel adjustment clause should provide for two adjustments per year.

Conclusions of Law: An electric utility with a fuel adjustment clause must file at least one adjustment to its fuel adjustment clause in each true-up year coinciding with the true-up of its fuel adjustment clause.[108] The Commission has discretion to authorize any utility with a fuel adjustment clause to file up to three additional adjustments to its fuel adjustment clause within a true-up year.[109] The Commission concludes it may lawfully limit the adjustments to twice each year.

---

[107] Williams Surrebuttal, Ex. 34, pages 10–12.

[108] 4 CSR 240-20.090(4)(A).

[109] *Id*.

vi. Should the fuel adjustment clause require a phase-in for sharp changes in fuel or purchased power costs, contain a "soft cap"?

SIEUA, AG-P and FEA witness Donald Johnstone proposed that any rate increase resulting from increased fuel and purchased power cost flowing through the fuel adjustment clause be limited to a "soft cap" of 3% annually."[110] Any amount in excess of the "soft cap" would be recovered with interest in the 12-month period immediately following the standard 12-month recovery period.[111] Further, although Aquila's fuel adjustment clause proposal does not include a "soft cap," Aquila does not oppose such a cap provided it is set at a reasonable level of at least 6% annually.[112]

While a "soft cap" might prevent customers' bills from rising significantly during the first year of the fuel adjustment clause, the Commission is concerned that any "soft cap" could result in those same customers facing greater price increases in the future, especially if current upward trends in fuel and purchased power costs continue.[113] AARP witness Nancy Brockway argues convincingly that it is not appropriate to include a "soft cap" in the approved fuel adjustment clause, because it would simply defer certain increases to future periods with interest, and likely result in even greater rate shock.[114]

Findings of Fact: The Commission finds, as recommended by witness Nancy Brockway, a "soft cap" to be inappropriate, due to the potential for rate shock.

---

110 Johnstone Rebuttal, Ex. 505, page 24, line 10 to page 25, line 9.

111 *Id*.

112 Williams Surrebuttal, Ex. 34, pages 24-25.

113 As discussed infra, Aquila has experienced a 13-20% annual increases in fuel and purchased power costs over the last three years.

114 Tr. page 863.

Conclusions of Law: The Commission concludes it has the discretion in the application of a "soft cap," which is not warranted in this instance.

vii. Should the fuel adjustment clause include performance standards? As part of their "alternative" fuel adjustment clause, SIEUA, AG-P and FEA asked the Commission to adopt specific performance standards that would apply to the coal-fired generating plants that Aquila uses to satisfy its base load power requirements.[115] SIEUA, AG-P and FEA witness Donald Johnstone argued the standards are necessary to protect consumers from the expense of higher-cost replacement power Aquila might have to acquire if there is an outage in one of its lower-cost base load units.[116] However, unless Aquila imprudently shuts down a base load facility, it should be allowed to recover reasonable costs for purchasing replacement power while such a facility is non-operational. Accordingly, for Mr. Johnstone's proposal to be reasonable, the Commission would have to assume Aquila would imprudently shut down one of its base load generating facilities. The Commission has no reason to believe Aquila would do this. In any event, the prudence of any replacement power cost purchased due to Aquila's shutting down of a base load unit should be addressed in the annual prudence reviews included in Aquila's proposed fuel adjustment clause.

Findings of Fact: The Commission finds it unreasonable to assume Aquila might imprudently shut down one of its base load generating facilities. The Commission further finds the prudence of any replacement power cost purchased due to Aquila's

115 Johnstone Rebuttal, Ex. 505, page 16, line 17 through page 18, line 2.

116 *Id*.

shutting down of a base load unit should be addressed in the annual prudence reviews included in Aquila's proposed fuel adjustment clause.

Conclusions of Law: The Commission concludes it has sufficient remedies available to deter imprudent action by Aquila and regular performance reviews are required under the law to detect imprudent action. The Commission finds no performance standards shall be included in the fuel adjustment clause.

viii. At what level, or under what formula, should over or under collection of fuel and purchased power costs be passed through the fuel adjustment clause?

Aquila's proposed fuel adjustment clause provides for a complete pass-through of 100% of prudently incurred fuel and purchased power costs above or below the amount included in base rates.[117] Aquila argues this assures customers will only bear the actual cost of fuel and energy that the Company prudently incurs in order to provide service.

AARP witness Nancy Brockway and SIEUA, AG-P and FEA witness Donald Johnstone each recommended the Commission only authorize Aquila to flow 50% of its prudently incurred fuel and purchased power costs above those in base rates through the fuel adjustment clause (50% flow-through).[118] They contend this type of sharing mechanism must be incorporated into any fuel adjustment clause to ensure Aquila will act prudently in procuring the fuel and purchased power necessary to provide service to its

---

[117] Williams Rebuttal, Ex. 33, pages 11-12; and Williams Surrebuttal, Ex. 34, pages 17-23.

[118] Brockway Surrebuttal, Ex. 601, pages 6-7; Tr. page 881, lines 17–23; Johnstone Rebuttal, Ex. 505, page 13, line 10 to page 15, line 10.

customers.[119] They further argue prudence reviews are ineffectual, in that they are an imperfect tool for catching inefficiency and eliminating its effects from rates.[120]

Aquila witness Dennis Williams objects to the proposed 50% flow-through because it would: 1) prohibit Aquila from collecting from customers a portion of its fuel and purchased power costs, even if those costs were determined to have been prudently incurred, and 2) prohibit customers from receiving the full benefit of any decreases in fuel and energy costs.[121]

As discussed above, in the Stipulation as to Certain Issues, Aquila's fuel and purchase cost was set at approximately $ 200,000,000. Aquila has experienced an increase of between 13% and 20% annually for each of the last 3 years. Under a 50% pass-through scenario, if Aquila's fuel and purchased power costs continued to increase by 15% annually, Aquila would under recover approximately $15,000,000 in prudently incurred fuel and purchased power expense in the 12 months following the conclusion of this case, and possibly $45,000,000 within 24 months.[122]

When asked how Aquila would recover the millions in prudently incurred costs that would not be recovered by a 50% pass-through fuel adjustment clause, SIEUA, AG-P and FEA witness Donald Johnstone stated "when costs go up you've got manage your business in a way to - - to have earnings. And so you have to control all of your costs to be equal to your revenues." Mr. Johnstone declined to offer any theories on where or how Aquila might be able to reduce other costs to compensate for the $15 to $45 million in

[119] *Id*.

[120] *Id*.

[121] Williams Rebuttal, Ex. 33, pages 11 - 12; and Williams Surrebuttal, Ex. 34, pages 17 -23.

[122] Tr. page 782.

prudently incurred fuel and purchased power cost it would not be allowed to recover under his proposal.

While the Commission believes Aquila should be given the opportunity to recover its prudently incurred fuel costs, it also agrees with Mr. Johnstone and Ms. Brockway that: 1) after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down; and 2) the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to allow less than 100% pass through of those costs.[123] Accordingly, it is not appropriate to allow Aquila to pass 100% of its fuel and purchased power costs, above those included in its base rates, through its fuel adjustment clause.

As set out above, without a fuel cost adjustment mechanism, if Aquila's fuel and purchased power costs increase by 15% in each of the next two years, Aquila will under recover $30 million in prudently incurred costs in the first year and $60 million in the second year. Under the 50% pass-through proposal, Aquila would still under-recover $15 million and $30 million in the first and second year respectively. Clearly, any adjustment mechanism that would authorize such under-recovery would be a violation of Section 386.266.4(1), in that, it would not afford Aquila a sufficient opportunity to earn a fair return on equity. In contrast, under a 95% pass-through, again assuming a 15% increase in Aquila's fuel and purchased power costs, Aquila would under recover its prudently incurred costs by only $1.5 million and $3.0 million the first and second year respectively.

[123] Brockway Surrebuttal, Ex. 601, pages 6–7; Tr. pages 847-849 and 878-885; Johnstone Rebuttal, Ex. 505, page 13, line 10 through page 15, line 10.

Findings of Fact: The Commission finds Mr. Williams' testimony on the issue is more persuasive, and further finds a 50% flow-through would not allow sufficient recovery of prudent fuel and purchased power costs.

The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.

The Commission finds allowing Aquila to pass 95% of its prudently incurred fuel and purchased power costs, above those included in its base rates, through its fuel adjustment clause is appropriate. With a 95% pass-through, the Commission finds Aquila will be protected from extreme fluctuations in fuel and purchased power cost, yet retain a significant 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.

Conclusions of Law: The Commission concludes allowing Aquila to only pass 50% of its prudently incurred fuel and purchased power costs through its fuel adjustment clause is not in keeping with the legislative intent of Section 386.266.4(1), which requires any RAM approved by the Commission be "reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity."

As set out above, without a fuel cost adjustment mechanism, if Aquila's fuel and purchased power costs increase by 15% in each of the next two years, Aquila will under recover $30 million in prudently incurred costs in the first year and $60 million in the second year, totally $90 million over the two-year-period. Under the 50% pass-through proposal, Aquila would still under-recover $15 million and $30 million in the first and second year respectively. Any adjustment mechanism authorizing such under-recovery would be a violation of Section 386.266.4(1).

The Commission concludes that a 95% pass-through would not violate Section 386.266.4(1), in that it would still afford Aquila a sufficient opportunity to earn a fair return on equity.

2. **Return on Common Equity:** What return on common equity should be used for determining Aquila's rate of return?

Four financial analysts offered recommendations regarding an appropriate return on equity in this case. Testifying on behalf of Aquila, Samuel C. Hadaway, a consultant from Austin, Texas who holds an economics degree for Southern Methodist University, as well as, a Masters in Business Administration and a Ph.D. from the University of Texas at Austin,[124] recommends Aquila be allowed a return on equity of 11.25%[125] Testifying on behalf of SIEUA, AG-P and FEA, Michael Gorman, a consultant from St. Louis, Missouri who holds a Masters in Business Administration with a concentration in finance from the University of Illinois at Springfield, recommends Aquila be allowed a return on equity of 10.0 %.[126] David C. Parcell, a consultant from Virginia who holds a Masters in Business Administration from Virginia Commonwealth University, testified on behalf of Staff. He recommends Aquila be allowed a return on equity between 9.0% and 10.25%, with the mid-

---

[124] Hadaway Direct, Ex. 13, page 1, lines 3-11.

[125] Hadaway Rebuttal, Ex. 14, page 19, lines 13-14.

[126] Gorman Direct, Ex. 507, page 17, and Appendix A.

point of his recommendation being 9.625%.[127] In addition, Russell Trippensee, the Chief Utility Accountant for the Public Counsel, who holds an accounting degree from the University of Missouri at Columbia, testified on behalf of Public Counsel. Mr. Trippensee offered analysis of the recommendations made by the other experts, but did not recommend a specific rate of return on equity.[128]

There is one more source the Commission can use as a guidepost in establishing an appropriate return on equity. In a survey of regulatory decisions from around the country, as reported by Regulatory Research Associates, the average allowed return in the electric utility industry for 2006 was 10.36%, with a median return of 10.25%.[129]

The Commission does not believe it would be appropriate for its return on equity finding to unthinkingly mirror the national average. Obviously, if all commissions took that approach returns on equity would never change, despite changing economic conditions, leading to unreasonable results. However, the national average is a good indicator of the capital market in which Aquila will have to compete for the equity needed to finance its operations. The Commission has an obligation under the law, as well as a matter of practical necessity, to allow Aquila an opportunity to earn a return that will allow it to compete in the capital market. No one, including ratepayers, benefit if Aquila is starved for capital.

In recent rate cases, the Commission has used what has been described as a zone of reasonableness to assist it in evaluating the recommendations offered by return on equity experts. The zone of reasonableness has been described as a range 100 basis

---

[127] Parcell Direct, Ex. 221, page 1, lines 14-27, and page 31 line 5-6.

[128] Trippensee Direct, Ex. 403, pages 1-2.

[129] Ex. 241.

points above and 100 basis points below the national average allowed return on equity. If the national average is taken to be 10.36%, then the zone of reasonableness runs from 9.36% to 11.36%.[130]

Aquila, Staff, SIEUA, AG-P, and FEA sponsored financial analysts who recommended a return on equity in this case. Their recommended ROEs are: Aquila – 10.25%, plus a 50 basis point adder; Staff – 9.0-10.25%; SIEUA, AG-P and FEA – 10%, with a 30 basis point reduction if a fuel adjustment clause is authorized. All proposed ROE recommendations fall within of the "zone of reasonableness." The Commission will next analyze the various ROE recommendations proposed by the parties.

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. However, a recommendation that greatly varies from the national norm will be viewed with skepticism.

Each expert witness performed multiple calculations using various methods to justify their recommendations for the return on equity the Commission should use in calculating the rates Aquila will be allowed to charge its customers. Collectively, they devoted hundreds of pages of testimony to discrediting each others' opinions. In the end, despite their best efforts to educate, the experts have managed to create a thicket of conflicting opinions. If the Commission were to attempt to force its way through the tangle it could easily lose its way or even become ensnared.

---

[130] Ex. 240, page 7.

To avoid becoming tangled in that thicket, the Commission must study the issue from a greater distance. Rather than attempt to untangle each of the narrow, technical disputes between the parties, the Commission will attempt to step back and examine the problem from a broader perspective.

When the Commission steps back, the first pattern that emerges is the realization that the rate of return advocated by the expert who testified for Aquila is too high. It appears as though Dr. Hadaway designed a methodology to achieve the same return the Commission approved for Kansas City Power & Light Company in Case No. ER-2006-0314.[131]

In large part, the overly high return on equity recommendation put forward by Dr. Hadaway results from his inclusion of a 50 basis point construction risk add-on premium, based on Aquila's allegedly greater construction risk.[132] Dr. Hadaway testified Aquila's six-year construction expenditures as a percentage of net plant is 118.2%, compared to an average of 60.9% for the comparable group.[133] Despite his advocacy of an adjustment to account for Aquila's alleged increased construction risk, Dr. Hadaway admits his entire construction risk adjustment is based upon Aquila's "**projected, estimated"** construction expenditures over the next six years.[134] Further, Dr. Hadaway admitted that in comparing construction risk, he compared more recent Aquila estimates to older estimates for the comparable utilities.[135]

---

[131] *Report and Order*, issued December 21, 2006, Case No. ER-2006-0314.

[132] Hadaway Rebuttal, Ex. 14, page 19, lines 6-13.

[133] *Id*.

[134] Tr. pages 322-323.

[135] Tr. pages 416-417.

In addition to the obvious incongruity of a large construction risk adjustment for a company based on projected and estimated construction expenditures, the opposing experts convincingly explained that Dr. Hadaway's return on equity recommendation and proposed construction adjustment are inappropriately inflated for more technical reasons as well. In particular, the Commission accepts as credible the testimony of SIEUA, AG-P, and FEA's witness, Michael Gorman, who explains that Dr. Hadaway's failure to acknowledge offsetting financial risks results in an improper evaluation of the construction and financial risk differential between the proxy groups and Aquila.[136] Dr. Hadaway's proposed adjustment for construction risk is an incomplete assessment of Aquila's overall risk because it ignores other aspects of risk that make Aquila less risky than many of the comparable companies, including: nuclear operations, operations in deregulated states, non-regulated affiliates, and hurricane risk.[137] In sum, the construction risk upward adjustment proposed by Dr. Hadaway appears to be a transparent effort to inflate the company's proposed return on equity.

On the other side of the thicket, the Commission finds the return on equity proposed by Staff Witness Parcell is too low. If the Commission were to adopt the return on equity he advocates, Aquila would have one of the lowest allowed returns on equity in the country. Parcell's group of comparable proxy companies includes several companies owning no generation and are therefore exposed to significantly lower risk.[138] Only Parcell's high point of 10.25% seems reasonable under these circumstances.

---

[136] Gorman Rebuttal, Ex. 508, pages 5-6.

[137] Tr. pages 334-364.

[138] Parcell Direct, Ex. 221, pages 20-31, and Tr. pages 496-497.

In setting rates the Commission's obligation is to reasonably balance shareholder and ratepayer interests. This is not an intellectual game designed to fatten or drive down the company's bottom line. Economic theories must be tempered by a realistic appraisal of the effect the numbers derived from those theories will have on the company and on ratepayers. For once, the Commission would like to see a rate case in which the witnesses presented by the parties present a balanced analysis rather than racing to the extremes.

Of the witnesses who testified in this case Michael Gorman, the witness for SIEUA, AG-P and FEA, did the best job of presenting the balanced analysis the Commission seeks, but even his analysis was lacking in certain aspects. His overall recommendation was for a return on equity of 10.0%. Mr. Gorman performed three different analyses to arrive at his overall recommendation. His Constant Growth Discounted Cash Flow (DCF)[139] analysis resulted in a recommended return on equity of 9.4 percent using his comparable group and 9.5% using Dr. Hadaway's comparable group,[140] his Bond Yield Plus Risk Premium Model analysis results in a recommended return on equity of 10.0% for both his proxy group and Dr. Hadaway's proxy group,[141] and his Capital Asset Pricing Model (CAPM)[142] results in a recommended return on equity of 10.2% using his proxy group and 10.6% using Dr. Hadaway's proxy group.[143] Mr. Gorman's overall recommendation of 10.0% is then a blending of these three analyses.

---

[139] Gorman explains that "[t]he DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return (ROR) or cost of capital." Gorman Direct, Ex. 507, page 20, lines 15-17.

[140] *Id*. at page 23, lines 9-11, and page 34, TABLE 4.

[141] *Id*. at page 19, lines 5-6, and page 34, TABLE 4.

[142] Gorman explains that "[t]he CAPM method of analysis is based upon the theory that the market required ROR for a security is equal to the risk-free ROR, plus a risk premium associated with the specific security." *Id*. at page 29, lines 9-11.

[143] Id. at Page 19, Lines 15-16, and page 34, TABLE 4.

On cross-examination, Mr. Gorman indicated his 10.0% recommendation presumed Aquila would not be granted a fuel adjustment clause, and if the Commission awards Aquila a fuel adjustment clause, his recommendation would drop by thirty basis points to 9.7%.[144] Public Counsel witness Russell Trippensee also stated that any ROE recommendation should be reduced if Aquila is authorized to establish a fuel adjustment clause.[145]

All the experts agree having a cost recovery mechanism, such as a fuel adjustment clause, results in less risk for a company and a company's return on equity should be decreased to compensate. The question then becomes whether that decrease in business risk is already reflected in Mr. Gorman's return on equity recommendation.

Mr. Gorman's testimony is lacking in this area in that there is insufficient evidence in the record to determine whether the companies in Mr. Gorman's proxy group have cost recovery mechanisms. However, 18 of the 24 companies in Dr. Hadaway's proxy group have fuel cost recovery mechanisms.[146] Mr. Gorman performed his three analyses using his proxy group and then again utilizing Dr. Hadaway's proxy group.[147] He obtained very similar results irrespective of which group was used.[148] Accordingly, the Commission finds the decreased risk associated with having a cost recovery mechanism is already accounted for in Mr. Gorman's return on equity calculation and no additional adjustment is necessary.

---

[144] Tr. pages 532-533.

[145] Trippensee Direct, Ex. 403, pages 7-8.

[146] Hadaway Rebuttal, Ex. 14, page 18, lines 4-16.

[147] *Id*.

[148] *Id*.

Findings of Fact: The Commission finds that none of the experts' final results appear to be reasonable. The 11.25% rate of return advocated by the expert who testified for Aquila, Dr. Hadaway, is too high. Dr. Hadaway's failure to acknowledge or account for financial risks faced by the comparable companies, that are either not faced by Aquila, or faced to a lessor degree, resulted in an improper inflation of his rate of return recommendation.

Dr. Hadaway's 50 basis point construction risk adjustment based upon "projected" and "estimated" construction expenditures as a percentage of existing plant over the next six years is inappropriately high, especially given that he compared current Aquila estimates to older estimates for the comparable companies. A more modest adjustment of 10 to 15 basis points is appropriate.

Michael Gorman, the witness for SIEUA, AG-P and FEA, did the best job of presenting the balanced analysis the Commission seeks. In examining Mr. Gorman's three analyses, the results of his DCF analysis are somewhat inconsistent with the results of the other two analyses and should be excluded. Utilizing the results of Mr. Gorman's Risk Premium and CAPM, Aquila's return on equity should be in the low 10% area. Next, Aquila's return on equity should be adjusted upwards by 10 to 15 basis points to reflect its increased construction risk compared to the comparable companies, as well as the fact the company is not recovering 100% of its prudently incurred fuel and purchased power costs.

A cost recovery mechanism, such as a fuel adjustment clause, results in a bit less risk for a company and a company's return on equity should be decreased to compensate. However, the Commission finds the decreased risk associated with having a cost recovery mechanism is already accounted for in Mr. Gorman's return on equity calculation and no additional adjustment is necessary.

Based on its analysis of the expert testimony offered by the parties, and on its balancing of the interest of the company's ratepayers and shareholders the Commission finds 10.25% is a fair and reasonable return on equity for Aquila that will allow it to compete in the capital market for the funds needed to maintain its financial health. Based upon a 10.25% return on equity, Aquila's revenue requirement increase will be approximately $13.6 million and $45.1 million for it L&P and MPS Operating Divisions, respectively.

Conclusions of Law: The Commission must draw primary guidance in the evaluation of the expert testimony from the Supreme Court's *Hope* and *Bluefield* decisions. [149] Pursuant to those decisions, returns for Aquila's investors must be commensurate with returns in other enterprises with corresponding risks.[150] 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.[151]

Investor expectations of Aquila are not the sole determiners of ROE under *Hope* and *Bluefield*, we must then compare it to the performance of other companies that are similar to Aquila in terms of risk. *Hope* and *Bluefield* also expressly refer to objective measures.[152] The allowed return must be sufficient to ensure confidence in the financial

---

[149] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 33, 345 (1943); and *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 690, 43 S.Ct. 675, 678, 67 L. Ed. 1176, 1181 (1923).

[150] *Id*.

[151] *Id*.

[152] *Id*.

integrity of the company in order to maintain its credit and attract necessary capital. By referring to confidence, the Court again emphasized risk.

In its decision in *Missouri Gas Energy*, the Commission stated that it does not believe its return on equity finding should "unthinkingly mirror the national average."[153] However, the national average is an indicator of the capital market in which Aquila will have to compete for necessary capital. One requirement imposed by *Hope* and *Bluefield* is that Aquila's rates be sufficient to permit it to obtain necessary capital.[154]

Based on its analysis of the expert testimony offered by the parties, and on its balancing of the interest of the company's ratepayers and shareholders the Commission finds a ROE of 10.25% satisfies the *Hope* and *Bluefield* standards and is a fair and reasonable return on equity for Aquila.

3. Accounting Authority Order – Sibley Generating Facility: Should the unamortized balances of the Sibley AAOs be included in Aquila's rate base in this case?

The Commission has the regulatory authority to grant a form of relief to a utility in the form of an accounting technique, an accounting authority order (AAO).[155] An AAO allows a utility to defer and capitalize certain expenses until the time it files its next rate case, and it protects the utility from earnings shortfalls and softens the blow which results from extraordinary construction programs.[156]

---

[153] *In the Matter of Missouri Gas Energy*, Case No. GR-2004-0209 (*Report & Order*, issued Sept. 21, 2004) .

[154] *Hope*, 320 U.S. at 603; *Bluefield*, 262 U.S. at 690.

[155] *Missouri Gas Energy v. Public Service Commission State of Missouri*, 978 S.W.2d 434 (Mo. App. 1998).

[156] *Id.*

The Commission granted Aquila two AAOs associated with expenditures involving its Sibley Rebuild and Western Coal Conversion product. [157] These projects were undertaken to extend the useful life of the Sibley Generating Station by 20 years and to comply with the 1990 Federal Clean Air Act.[158] This project avoided building a new generation plant at substantially higher costs and allowed the Sibley unit to burn low sulfur western coal to meet environmental requirements.[159]

To avoid the need to purchase other power resources to meet the peak season demand, work on these projects was only conducted in off-peak periods.[160] This approach provided for a substantial savings for Aquila's customers, but caused recovery problems for the company because it took several years to complete.[161] If the Commission had not granted Aquila an AAO, Aquila would have been unable to recover the cost of system upgrades without filing annual rate cases.

In its December 27, 1989 *Order Concerning Application for Approval of Accounting Procedure and Consolidating Dockets*, Case No. EO-90-114 and *Report and Order* in Case Nos. EO-91-358 and EO-91-360, the Commission concluded these expenses were extraordinary in nature and justified the special accounting treatment.[162] By allowing the deferral of these costs, the Commission allowed Aquila to stage the Sibley projects, thereby saving its customers the expense of purchasing alternate power resources during peak-demand periods, and also avoiding a series of rate cases to capture

---

[157] Kolte Surrebuttal, Ex.19, page 4, lines 6-13.

[158] *Id*.

[159] *Id*.

[160] *Id.* at lines 16-22.

[161] *Id*. at page. 4, line 22 to page 5, line 2.

[162] 1 Mo. P.S.C. 3rd 200 (1991).

the staged elements of those projects.[163] In each case, the Commission allowed the amortization of the expense over a 20-year period, plus the inclusion of the unamortized amount in rate base.[164]

Aquila witness Ron Kolte and Staff witness Philip Williams each contend that the unamortized balances of the Sibley AAOs should be included in rate base in this case.[165] In support of that position, Mr. Williams and Mr. Kolte testify the public policy analysis upon which the Commission based its decision to initially authorize the Sibley AAOs is still sound.[166] Mr. Williams further testified that allowing a continuation of construction accounting of major capital projects by an AAO and including those construction costs in rate base provides an incentive for the utility to commit significant capital investment on a timely basis.[167] Both Mr. Kolte and Mr. Williams state that the Commission has already granted the AAOs and incorporated them in prior rate cases and should do so again here.[168]

Public Counsel contends the Commission should deny rate base treatment for the unamortized deferred cost balance allowed by the AAOs.[169] Public Counsel argues inclusion of these balances in the rate base would be inconsistent with the purpose of the AAO mechanism as a remedy to mitigate the impact of regulatory lag. Public Counsel appears to object to the AAOs on the basis that their balances include property taxes,

---

[163] *Id*.

[164] Tr. page 94, lines 21-23.

[165] P. Williams Rebuttal, Ex 236, pages 3-4; and Kolte Surrebuttal, Ex. 18, pages 2-9.

[166] *Id*.

[167] P. Williams Rebuttal, Ex. 236, page 6, line 19 to page 7, line 5.

[168] P. Williams Rebuttal, Ex. 236, pages 3-4; and Kolte Surrebuttal, Ex. 18, pages 2-9.

[169] Robertson Rebuttal, Ex. 406, pages 9-17.

carrying costs and depreciation expense related to the originally deferred amounts.[170] Public Counsel claims these items are book entries rather than actual capital outlays of real dollars and that Aquila should not be allowed to earn a return on these amounts.[171]

The Commission agrees with Public Counsel that AAOs are to be considered on a case-by-case basis, and that the Commission can revisit the issue and is not bound by its prior determinations. However, the Commission agrees with Mr. Williams and Mr. Kolte that the public policy analysis upon which the Commission based its decision to initially authorize the Sibley AAOs is still sound.[172] The deferred costs included in the Sibley AAOs represent major capital additions to plant in service and should be treated the same way as other capital costs for these projects, and afforded rate base treatment. Further, absent AAO treatment, these amounts would have been lost as a result of booking these costs directly to expense following completion of the projects.[173] The Commission finds the unamortized balances of the Sibley AAOs should be included in Aquila's rate base in this case.

Findings of Fact: The Commission agrees with Staff and Aquila that the public policy analysis upon which the Commission based its decision to initially authorize the Sibley AAOs is still sound. The deferred costs included in the Sibley AAOs represent major capital additions to plant in service and should be treated the same way as other capital costs for these projects, and afforded rate base treatment.

---

[170] *Id*.

[171] *Id.*

[172] P. Williams Rebuttal, Ex. 236, pages 3-4; and Kolte Surrebuttal, Ex. 18, pages 2-9

[173] Tr. page 96, lines 15-24.

Conclusions of Law: The Commission has the regulatory authority to grant a form of relief to a utility in the form of an accounting technique, an accounting authority order (AAO). An AAO allows a utility to defer and capitalize certain expenses until the time it files its next rate case, and it protects the utility from earnings shortfalls and softens the blow which results from extraordinary construction programs. While AAOs are to be considered on a case-by-case basis, and the Commission can revisit the issue and is not bound by its prior determinations, the deferred costs included in the unamortized balances of the Sibley AAOs, represent major capital additions to plant in service, and should be included in Aquila's rate base in this case.

4. Depreciation: What depreciation rates should be used to determine rates in this case?

Staff and Aquila maintain that Aquila's currently approved depreciation rates should be used to set rates in this case. Initially, SIEUA, AG-P and FEA opposed Aquila's use of those depreciation rates. No other party took a position on this issue.

During the evidentiary hearing, counsel for SIEUA, AG-P and FEA advised the Commission they were dropping the depreciation issue and were now agreeing that Aquila's current depreciation rates should be used in this case.[174]

Findings of Fact: The Commission finds Aquila's currently approved depreciation rates are appropriate to use to determine rates in this case. The Commission further finds no party objects to the use of those depreciation rates.

---

[174] Tr. page 464, lines 4 - 8.

Conclusions of Law: The Commission finds Aquila's currently approved depreciation rates are appropriate and will be used to determine appropriate rates in this case.

G. The Settled Issues

Many issues were resolved by the agreement of the parties. On April 4, 2007, a Stipulation and Agreement as to Certain Issues was filed and served on the parties. Each party that did not sign the stipulation filed an official statement indicating it did not oppose the stipulation. As permitted by its regulations, the Commission treated the unopposed stipulation and agreement as a unanimous partial stipulation and agreement.[175] After considering the stipulation and agreement, the Commission approved it as a resolution of the issues addressed in that agreement.[176] The issues that were resolved by the approved stipulation and agreement will not be further addressed in this report and order.

IT IS ORDERED THAT:

1. Subject to the conditions set out in the body of this order, Aquila is granted a waiver from the following requirements contained in Commission Rule 4 CSR 240-20.090(9): the requirement to include line loss factors in its original fuel adjustment clause filing, and the requirement to include line loss factors in its fuel adjustment clause that are based upon a line loss study completed within twenty-four months of that fuel adjustment clause filing.

---

[175] 4 CSR 240-2.115(2).

[176] An *Order Approving Stipulation and Agreement as to Certain Issues* was issued on April 12, 2007.

2. Aquila is granted a waiver of Commission Rule 4 CSR 240-3.161(2)(P), subject to the conditions set out in the body of this order.

3. The proposed electric service tariff sheets submitted under Tariff File No. YE-2007-0001 on July 3, 2007, by Aquila, Inc., d/b/a Aquila Networks MPS and Aquila Networks L&P for the purpose of increasing rates for retail electric service to customers are hereby rejected. The specific sheets rejected are:

P.S.C. Mo. No. 1

3rd Revised Sheet No. 2, Canceling 2nd Revised Sheet No. 2
2nd Revised Sheet No. 18, Canceling 1st Revised Sheet No. 18
2nd Revised Sheet No. 19, Canceling 1st Revised Sheet No. 19
2nd Revised Sheet No. 21, Canceling 1st Revised Sheet No. 21
2nd Revised Sheet No. 22, Canceling 1st Revised Sheet No. 22
2nd Revised Sheet No. 23, Canceling 1st Revised Sheet No. 23
2nd Revised Sheet No. 24, Canceling 1st Revised Sheet No. 24
2nd Revised Sheet No. 25, Canceling1st Revised Sheet No. 25
2nd Revised Sheet No. 28, Canceling 1st Revised Sheet No. 28
2nd Revised Sheet No. 29, Canceling 1st Revised Sheet No. 29
2nd Revised Sheet No. 30, Canceling 1st Revised Sheet No. 30
2nd Revised Sheet No. 31, Canceling 1st Revised Sheet No. 31
2nd Revised Sheet No. 33, Canceling 1st Revised Sheet No. 33
2nd Revised Sheet No. 34, Canceling 1st Revised Sheet No. 34
2nd Revised Sheet No. 35, Canceling 1st Revised Sheet No. 35
1st Revised Sheet No. 36, Canceling Original Sheet No. 36
2nd Revised Sheet No. 41, Canceling 1st Revised Sheet No. 41
2nd Revised Sheet No. 42, Canceling 1st Revised Sheet No. 42
2nd Revised Sheet No. 43, Canceling 1st Revised Sheet No. 43
2nd Revised Sheet No. 44, Canceling 1st Revised Sheet No. 44
1st Revised Sheet No. 46, Canceling Original Sheet No. 46
2nd Revised Sheet No. 47, Canceling 1st Revised Sheet No. 47
2nd Revised Sheet No. 48, Canceling1st Revised Sheet No. 48
1st Revised Sheet No. 49, Canceling Original Sheet No. 49
2nd Revised Sheet No. 50, Canceling 1st Revised Sheet No. 50
2nd Revised Sheet No. 51, Canceling 1st Revised Sheet No. 51
2nd Revised Sheet No. 52, Canceling 1st Revised Sheet No. 52
2nd Revised Sheet No. 53, Canceling 1st Revised Sheet No. 53
2nd Revised Sheet No. 54, Canceling 1st Revised Sheet No. 54
2nd Revised Sheet No. 55, Canceling 1st Revised Sheet No. 55
2nd Revised Sheet No. 56, Canceling 1st Revised Sheet No. 56
2nd Revised Sheet No. 57, Canceling 1st Revised Sheet No. 57

1st Revised Sheet No. 58, Canceling Original Sheet No. 58
2nd Revised Sheet No. 59, Canceling 1st Revised Sheet No. 59
2nd Revised Sheet No. 60, Canceling 1st Revised Sheet No. 60
2nd Revised Sheet No. 61, Canceling 1st Revised Sheet No. 61
2nd Revised Sheet No. 66, Canceling 1st Revised Sheet No. 66
2nd Revised Sheet No. 67, Canceling1st Revised Sheet No. 67
2nd Revised Sheet No. 68, Canceling 1st Revised Sheet No. 68
1st Revised Sheet No. 69, Canceling Original Sheet No. 69
2nd Revised Sheet No. 70, Canceling 1st Revised Sheet No. 70
2nd Revised Sheet No. 71, Canceling 1st Revised Sheet No. 71
2nd Revised Sheet No. 74, Canceling 1st Revised Sheet No. 74
2nd Revised Sheet No. 76, Canceling 1st Revised Sheet No. 76
2nd Revised Sheet No. 79, Canceling 1st Revised Sheet No. 79
2nd Revised Sheet No. 80, Canceling 1st Revised Sheet No. 80
1st Revised Sheet No. 82, Canceling Original Sheet No. 82
2nd Revised Sheet No. 88, Canceling 1st Revised Sheet No. 88
2nd Revised Sheet No. 89, Canceling 1st Revised Sheet No. 89
2nd Revised Sheet No. 90, Canceling 1st Revised Sheet No. 90
2nd Revised Sheet No. 91, Canceling 1st Revised Sheet No. 91
2nd Revised Sheet No. 92, Canceling 1st Revised Sheet No. 92
1st Revised Sheet No. 94, Canceling Original Sheet No. 94
2nd Revised Sheet No. 95, Canceling 1st Revised Sheet No. 95
2nd Revised Sheet No. 97, Canceling 1st Revised Sheet No. 97
2nd Revised Sheet No. 99, Canceling 1st Revised Sheet No. 99
2nd Revised Sheet No. 100, Canceling 1st Revised Sheet No. 100
2nd Revised Sheet No. 103 Canceling 1st Revised Sheet No. 103
2nd Revised Sheet No. 104, Canceling 1st Revised Sheet No. 104
Original Sheet No. 124
Original Sheet No. 125
Original Sheet No. 126

4. Aquila Inc., d/b/a Aquila Networks MPS and Aquila Networks L&P shall file proposed electric service tariff sheets in compliance with this Report and Order no later than midnight on May 20, 2007.

5. Aquila, Inc., shall complete the proposed heat rate and/or efficiency schedule and testing plan with written procedures, as described in 4 CSR 240-3.161(2)(P) that is either agreed to by all parties to this case or has been approved by the Commission no less than sixty (60) days before the effective date listed on the tariff for its initial fuel

adjustment clause filing for the purpose of adjusting a fuel adjustment clause rate pursuant to 4 CSR 240-3.161(7) and 4 CSR 240-20.090(4).

6. All pending motions, not otherwise disposed of herein, are hereby denied.

7. This Report and Order shall become effective on May 27, 2007.

BY THE COMMISSION

Colleen M. Dale
Secretary

(S E A L)

Davis, Chm., concurs, with separate
concurring opinion attached;
Murray, C., concurs;
Appling, C., concurs, with separate
concurring opinion attached;
Gaw, C., dissents, with separate
dissenting opinion to follow;
Clayton, C., dissents;
certify compliance with the provisions of
Section 536.080, RSMo.

Dated at Jefferson City, Missouri,
on this 17th day of May, 2007.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Tariffs of Aquila, Inc. d/b/a Aquila Networks –MPS and Aquila Networks-L&P Increasing Electric Rates for the Service Provided to Customers in the Aquila Networks MPS and Aquila Networks-L&P Service Areas.	))))))	**Case No. ER-2007-0004** Tariff No. YE-2007-0001

CONCURRING OPINION OF CHAIRMAN JEFF DAVIS

This commissioner corrects the concurrence filed on May 17, 2007. This concurrence corrects the numbers but does not change the substance of the concurrence.

This commissioner respectfully concurs with the majority decision in all parts; however, there are at least three points raised in this case worthy of further commentary: (1) Skyrocketing fuel prices are driving large rate increases for Aquila customers and, absent some change of circumstances, it is likely Aquila customers will see significant rate increases over the next few years; (2) This report and order marks the first time the Missouri Public Service Commission has implemented a fuel adjustment mechanism pursuant to Section 386.266 enacted in 2005 by the Missouri General Assembly with the passage of Senate Bill 179; and (3) The ex-parte communication from Pirate Capital in this case illustrates that the source of capital can be as important as the attraction of capital itself when determining what's in the public interest.

This opinion, like all other opinions, is based on the facts and circumstances of this particular case as well as preceding cases this body may recognize. Nothing in this opinion should be construed as to any position this commissioner might take in any case, currently pending or in the future.

1. Rising fuel prices dictated the majority of this rate increase and, absent some change in circumstances, this trend will likely continue.

Subject to the adjustments set out in paragraphs 5, 10 and 13 of the stipulation, all of the parties agreed to an increase of at least $40.6 million for Aquila's MPS territory and at least $12.7 million for its St. Joseph Light & Power property for a total of roughly $53.3 million. The actual award in this case is approximately $58.7 million. Further, the company is receiving a fuel adjustment mechanism (FAC).

This increase follows a $44.8 million rate increase awarded by this commission for both properties in February 2006. As stated in the majority opinion, fuel and purchased-power expenses make up approximately 46 percent of Aquila's total operating costs. These costs rose 13 percent to 20 percent annually over the three-year period ending June 30, 2006. This pattern of increases is of great concern because subsequent increases in fuel costs will necessitate Aquila seeking additional rate increases of a similar magnitude.

The light at the end of the tunnel – the rate stability so many of Aquila's customers are desperately seeking – appears to be years away. Aquila's fuel and purchased-power expenditures have increased rapidly in recent years. This underscores the perils of being a vertically integrated utility with a significant reliance on natural-gas fired generation and purchased power. The general trend appears to be that both the price of natural gas and the demand for purchased power will continue to increase. Those increased costs will ultimately be reflected in increased rates for Aquila customers.

The goal can and must be rate stability for consumers, even though that goal is challenging and may take years to accomplish. Aquila's fuel and purchased-power costs may well remain upwardly volatile until the company acquires more generation to meet both baseload and peak capacity demand. Aquila is taking steps to add generation capacity by partnering with KCP&L to construct the latan II Coal Plant and to construct two new natural gas-fueled electricity-generating turbines in Sedalia, Missouri.

While increasing generation capacity is essential to meeting baseload and peak demands for electricity, it is no panacea for Aquila's customers in terms of rate stability. Assuming the latan II coal plant is constructed on schedule in 2010, Aquila will be back in front of this commission seeking another substantive rate increase because the costs of power plant construction cannot be put into rates until the plant is "used and useful." (Chapter 393.135 RSMo, 2000) These costs could be compounded by compliance with future emissions requirements, particularly any federal action on carbon dioxide emissions (CO2).

2. This decision marks the first time this commission has implemented a fuel adjustment mechanism (FAC) pursuant to Section 386.266 approved by the General Assembly in Senate Bill 179 (2005 legislative session).

Lately, Aquila's rising fuel and purchased-power costs by themselves are enough to cause rate shock when those costs are eventually passed through to customers in the form of a rate case. Skyrocketing fuel and purchased power prices can compound rate risk for consumers because, when they necessitate a rate case, the company will also seek recovery of their rate case expenses as well as other expenses.

In 2005, the Missouri General Assembly enacted Senate Bill 179 to provide this commission with the option of using a fuel-adjustment mechanism as a tool to establish just and reasonable rates between rate case filings by incorporating market cost changes for prudent, necessary fuel and purchased-power costs.

More than 25 other states can use this method of utility rate regulation. It smoothes the impact of fuel-cost volatility spikes on consumers, minimizes rate shock resulting from the eventual pass-through of fuel and purchased power costs due to regulatory lag and spares both consumers and taxpayers the expense of a rate case when the principal cost driver is the cost of fuel and purchased power.

This commission recognizes the hardship rate volatility can place on all classes of consumers – residential, commercial and industrial. Further, we are all acutely aware of the need to institute safeguards to ensure fuel adjustment clauses do not allow utility service providers to incur fuel costs in an imprudent manner.

That being said, a line-item surcharge allowing a utility to recover its prudently incurred fuel and purchased-power costs is a necessary evil in the case of this particular company. In a time of rapidly rising fuel and purchased-power prices, there is no way a company like Aquila can earn its allowed return on equity by reducing its expenses by tens of millions of dollars in other areas to offset increased fuel and purchased-power costs. In short, fuel and purchased-power increases are dramatically outpacing the ability of the company to absorb these costs. When those expenses already amount to almost half of the company's total expenses, no amount of increased efficiency can offset tens of millions of dollars in new expenses.

The ability to earn an allowed return on equity is important. These earnings attract and sustain investment the company needs to expand generating capacity and maintain essential infrastructure. There is no disputing the Aquila system could use more investment.

Critics of Aquila will argue Aquila is responsible for its own difficulties. There is no doubt Aquila management shares some responsibility in creating this dilemma. Other than PSC staff's assertion that Aquila should have built and kept the Aries plat, no testimony has been offered in this proceeding or any other previous proceeding that said Aquila should have undertaken a plan to construct other electric generation alternatives a decade ago. In fact, the conventional wisdom of the late 90's was that that the price of natural gas would remain relatively stable and no one ever anticipated the price of natural gas peaking at more than $10.00/mmbtu. If those assumptions were correct, natural gas fired generation would have proven to be more cost-competitive with coal-fired generation.

These facts, when combined with the costly and exhaustive permitting process required by the Missouri Department of Natural Resources (DNR) in granting emissions permits, make it highly unlikely Aquila would have ever been able to construct a coal plant under those conditions. Accordingly, it is very difficult to accurately and proportionately balance the culpability of Aquila's management for the challenges the company now faces in containing costs related to providing reliable and affordable utility services to its customers.

All of the proposed FAC mechanisms in this case had some facet that was unappealing. Aquila's proposal to recover 100 percent of its fuel increase costs was technically sound, but failed to ensure prudent and necessary pass-through because the company incurred no risk of financial loss if it failed to prudently manage its fuel costs. The 95 percent pass-through adopted by the majority in this case is reasonable in that it allows the company to recover all or most of its fuel and purchased power costs above $200 million, while encouraging the company to be prudent. For instance, if fuel and purchased power costs increase by $30 million in one year to a level of $230 million total -- a likely scenario based on the testimony presented in this case -- the company will recover $28.5 million of those costs and lose $1.5 million.

A company like Aquila might be able to make up a $1.5 million annual shortfall and, based on judgment and experience, such a shortfall is reasonable under the circumstances. Thus, in my opinion, this approach is most reasonable under the circumstances facing Aquila and the customers it serves.

The other proposals considered by the PSC would have excessively penalized the company for fuel and purchased power costs far beyond its control. This would make it extremely difficult for the company to reinvest in infrastructure and to attract the investment capital necessary to maintain infrastructure and expand generation capacity.

I found the other proposed cost-sharing mechanisms unreasonable for the following reasons:

-an interim energy charge or I.E.C. similar to the one proposed in this case cost Aquila more than $20 million since their last rate case decision in February 2006. Accordingly, I did not feel comfortable adopting the methodology proposed by the PSC staff in this case.

-the 50-50 sharing proposal proposed by several parties of the parties is unfair for a company like Aquila. In scenarios such as that referenced above, Aquila has no means of possibly offsetting a loss of $15 million or more on an annual basis.

-the Wyoming Plan sponsored by AARP has some attractive features similar to the IEC in that it contained a deadband, which would require the utility to absorb costs within a certain range, and encouraged proportionate sharing with no cap. If the market for fuel and purchased power were less volatile, this proposal definitely would merit strong consideration; however, in an era of upward cost volatility, the deadband prohibits the utility from recovering a significant portion of its prudently incurred costs at the outset.

-Although intriguing, an accounting authority order (AAO) would be something this commissioner would gladly consider if this commission had no other alternative. The weakness of the AAO is that it will be thrown into the next rate case. Parties will make all sorts of arguments to disallow those expenses and the company will either agree to take less than they are otherwise entitled in settlement or run the risk of the commission arbitrarily making downward adjustments in other areas because the recovery of the AAO expenses has the potential of being such a large issue.

Absent certainty of fuel cost variances, some aspects of rate setting are like rate design in that they are more art that science. Although the parties are to be commended for coming to an agreement on how the process should work, their extreme positions left this commission in the position of having to try develop a FAC mechanism that would be just and reasonable to all parties.

Aquila should be very mindful that the majority of this commission took a bold step in awarding Aquila a fuel adjustment mechanism. This commission and the General Assembly will be watching. If Aquila fails to adopt a proper hedging strategy, fails to follow its hedging strategy or abuses the discretion given to it by this commission in any other way, this commissioner will not hesitate to modify or reject Aquila's FAC application in a future proceeding.

3. The ex-parte communication from Pirate Capital in this case illustrates the point that the source of capital is as important as the attraction of capital itself when determining what's in the public's best interest.

A. Concerns regarding the attraction of capital:

Attraction of capital is essential for all utilities, especially those who need to spend large sums of money to enhance reliability, improve infrastructure and add new generation. This is particularly true regarding baseload generation, which is more expensive and takes longer to construct.

Aquila is a vertically integrated utility needing to make significant investments in all three of these areas. This commission has to avoid the temptation of being punitive in rate proceedings to the extent it leaves a company vulnerable to problems caused by undercapitalization and inadequate earnings potential.

Missouri utilities, including Aquila, seem to have no problem attracting investment capital. However, recent events such as the collapse of the Amaranth hedge fund and its effect on the futures market for natural gas, the proposed acquisition of Texas Utilities (TXU) by private equity firms and Pirate Capital's rattling of the saber in the middle of this rate case begs the question of who's going to actually run the company and whether some investors require greater regulatory scrutiny.

Although the issue is not squarely in front of us in this case, the generally accepted principle that "cash is cash" may no longer be true when a group of new, more active investors pushes its way through the boardroom doors, and if the short-term interests of those investors collide with and ultimately prove detrimental to the long-term benefit of ratepayers – the public interest.

For instance, a five-year plan designed to reduce debt and improve Aquila's capital structure could ultimately increase the company's return in a rate case at the expense of delaying improvements necessary to enhance the reliability of the Aquila system. This type of action might be detrimental to the current generation of Aquila ratepayers in terms of reliability and risk further rate increases to the next generation of Aquila customers.

This Commission is likely to view a conscious decision by utility management to purchase power and pass it through a fuel adjustment mechanism, rather than construct appropriate generation resources as detrimental to ratepayers. Neither of these issues is before this commission today, but they are foreseeable, particularly where a company has demonstrated questionable decision-making ability in the past. This commission must be vigilant against conduct that is not in the long-term best interests of the state and its ratepayers.

B. Concerns regarding Aquila management decisions affecting the company's ability to attract capital:

The commission staff -- led by Bob Schallenberg, Director of the PSC's Utility Services Division -- and others here at the Commission have consistently taken a long-range view of utility planning – spanning 30 years or longer.[1] These views are most evident in cases where the prudence of constructing new generation assets is an issue. In those cases, the PSC staff has taken positions in favor of Missouri electric utilities owning their own electric generation because it is more reliable to have generation facilities located near the customers being served and cheaper once the costs are depreciated over a period of thirty years or longer. Companies that followed this strategy and built excess generation capacity, like KCP&L and Ameren UE, have used off-system sales of their excess electricity to subsidize costs to their regulated utility customers.

Both utilities and customers have benefited under this regulatory framework. Ameren UE and KCP&L generated earnings for their investors and avoided rate increases for almost two decades, while actually reducing the rates paid by their

1 Equally important to note is that, to the best of this commissioner's knowledge, the PSC staff has always opposed acquisition premiums being passed through to utility ratepayers and the Missouri PSC has never approved such a premium.

customers over that same period. This accomplishment is no small feat and provides strong support for the long-term approach espoused by Mr. Schallenberg and the rest of the PSC staff in this regard.

In contrast to Ameren UE and KCP&L, Aquila purchases a substantial portion of the electricity it needs to meet customer demands. Aquila even divested its interest in the Aries plant and then unsuccessfully tried to re-acquire the plant. The evidence in this case shows Aquila's fuel and purchased power expenses have risen rapidly and all relevant information at our disposal indicates that these costs will continue to rise -- the only question is how much?

Aquila needs more baseload generation and, according to the PSC staff, at least two more gas-fired turbines. Constructing power plants is expensive and these facilities constitute only a portion of Aquila's capital concerns. Based on the PSC staff's depreciation studies, Aquila's distribution system is one of the oldest in the state and likely in need of further investment. It could be argued that investments should have already been made, but simply weren't made because Aquila did not have the cash flow to make them.

Last year, the Office of Public Counsel (OPC) filed a request seeking a management audit of Aquila in case number EO-2006-0356. The PSC Staff performed a limited audit and Mr. Mills filed a response raising some very valid points on behalf of OPC in response to those findings on October 31, 2006. This commission subsequently issued an order "accepting" the report and directing Aquila to comply with all of the recommendations contained therein on March 13, 2007. Although the order was silent as to the issue, it is noteworthy that KCP&L's proposed acquisition of Aquila was announced in January 2007.[2] Had the proposed acquisition not been announced, it is almost a certainty that Aquila's management would have faced more scrutiny of its management decisions and this commission would be entertaining further suggestions from Mr. Mills' office. Pending the outcome of that case, we still might be considering further steps regarding Aquila management.

Mr. Mills is correct in that there are ample grounds for questioning the prudence of Aquila's management, past and present. These include:

> -Management decisions to pursue unregulated business ventures that eventually caused Aquila to hemorrhage money, lose its investment grade status and some would say neglect its customers for years;
>
> -The decision of Aquila to sell its interest in the Aries plant to Calpine and the subsequent mishandling of the zoning, siting and construction of the South Harper generating facility which will be a source of controversy for this commission, the courts and the legislature for years to come.
>
> -A subsequently corrected "accounting error" discovered in a previous rate case that under-funded employee pension benefits;
>
> -Aquila's decisions that led the company to pay $25 million to settle claims with the Commodities Futures Trading Commission (CFTC) and the PSC's subsequent lawsuit against Aquila Inc., Aquila Merchant Services, Inc., and other energy marketers seeking monetary damages for allegations of natural gas price manipulation.

C. How should this commission resolve lingering allegations of imprudence by Aquila management?

In fairness to Aquila's current management, I am not sure if different management would have been able to perform better given the same circumstances. Although I might agree with the PSC staff, OPC and other interested parties on a philosophical level, the commission employs a "reasonable person standard" to determine whether the company's decision was reasonable under the circumstances.

---

2 See Case No. EM-2007-0374

Imprudence on the part of a utility is difficult to prove under this standard for two reasons: First, the company is usually able to put forth some evidence its managers were acting prudently under the circumstances; and second, damages are often difficult, if not impossible, to quantify. That being said, when one considers the totality of the circumstances, Mr. Mills is justified in his desire that this commission keep a tight leash on Aquila.

There is no question Aquila's decisions have been detrimental to its ratepayers. That detriment is difficult, if not impossible, to quantify; nor is it feasible to calculate whether or not those decisions should have been dealt with by this commission in previous rate proceedings subsequent to the alleged imprudent behavior actually occurring. There is no clear answer to this question and these issues will continue to haunt Aquila management for years to come regardless of who's in charge.

Respectfully submitted,

Jeff Davis
Chairman

Dated at Jefferson City, Missouri,
on this 9th day of July, 2007.

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

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

REPORT AND ORDER

Issue Date: **May 4, 2011**

Effective Date: **May 14, 2011**

TABLE OF CONTENTS

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

REPORT AND ORDER

Appearances

James M. Fischer and **Larry W. Dority**, Fischer & Dority, P.C., 101 Madison Street, Suite 400, Jefferson City, Missouri 65101,

and

Heather A. Humphrey, General Counsel, and **Roger W. Steiner,** Corporate Counsel, Kansas City Power & Light Company, Kansas City Power & Light Company, Post Office Box 418679, Kansas City, Missouri 64141-9679,

and

Karl Zobrist and **Susan B. Cunningham**, SNR Denton US LLP, 4250 Main Street, Suite 1100. Kansas City, Missouri 64111,

and

Glenda Cafer, Cafer Law Office, L.L.C., 3321 Southwest Sixth Street, Topeka, Kansas 66606,

and

Charles W. Hatfield, Stinson Morrison Hecker, LLP, 230 West McCarty Street, Jefferson City, Missouri 65101, for Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.

Douglas L. Healy, Healy & Healy, LLC, 939 North Boonville Avenue, Suite A, Springfield, Missouri 65802, for Missouri Joint Municipal Electric Utility Commission.

Stuart W. Conrad, and **David L. Woodsmall,** Finnegan, Conrad & Peterson, L.C., 1209 Penntower Office Center, 3100 Broadway, Kansas City, Missouri 64111, for Praxair, Inc.; Ag Processing, Inc., a Cooperative; Sedalia Industrial Energy Users' Association; and Missouri Energy Users' Association (the Industrial Intervenors).

Carl J. Lumley, Curtis, Heinz, Garrett & O'Keefe, P.C., 130 South Bemiston, Suite 200, Clayton, Missouri, 63105, for Dogwood Energy, LLC.

Todd J. Jacobs, Senior Attorney, Missouri Gas Energy, 3420 Broadway, Kansas City, Missouri 64111,

and

Dean L. Cooper, Brydon, Swearengen & England P.C., 312 East Capitol Avenue, Post Office Box 436, Jefferson City, Missouri 65102, for Missouri Gas Energy, an Operating Division of Southern Union Company.

Thomas R. Schwarz, Jr., Blitz, Bardgett & Deutsch, L.C., 308 East High Street, Suite 301, Jefferson City, Missouri 65101, for the Missouri Retailers Association.

Mark. W. Comley, Newman, Comley & Ruth P.C., 601 Monroe Street, Suite 301, Post Office Box 537, Jefferson City, Missouri 65102-0537, for the City of Kansas City, Missouri, and the City of Lee‘s Summit, Missouri.

Michael R. Tripp, **Sarah E. Giboney**, and **James B. Lowery**, Smith Lewis, LLP, 111 South 9th Street, Columbia, Missouri 65201, for Union Electric Company, d/b/a Ameren Missouri (formerly d/b/a AmerenUE),

James C. Swearengen, **L. Russell Mitten**, and **Diana C. Carter**, Brydon, Swearengen & England P.C., 312 East Capitol Avenue, Post Office Box 436, Jefferson City, Missouri 65102, for The Empire District Electric Company.

Arthur Perry Bruder, Attorney-Advisor, Office of Assistant General Counsel for Electricity and Fossil Energy, United States Department of Energy, 1000 Independence Avenue, SW, Washington, D.C. 20585, for the United States Department of Energy.

Shayla L. McNeill, Captain, USAF, Air Force Legal Operations Agency, 139 Barnes Drive, Suite 1, Tyndall Air Force Base, Florida 32403-5319, for the Federal Executive Agencies.

Michael E. Amash, Blake & Uhlig, P.A., 753 State Avenue, Suite 475, Kansas City, Kansas 66101, for the International Brotherhood of Electrical Workers Local Unions No. 412, 1464, and 1613.

William D. Steinmeier, William D. Steinmeier, P.C., 2031 Tower Drive, Post Office Box 104595, Jefferson City, Missouri 65110-4595, for the City of St. Joseph, Missouri.

Sarah Mangelsdorf, Assistant General Counsel, Office of Attorney General, Post Office Box 899, Jefferson City, Missouri 65102, for the Missouri Department of Natural Resources.

John R. Kindschuh, Bryan Cave LLP, 13220 Metcalf, Suite 320, Overland Park, Kansas 66213, for the Missouri Industrial Energy Consumers, and Ford Motor Company.

John B. Coffman, John B. Coffman, LLC, 871 Tuxedo Boulevard, St. Louis, Missouri 63119-2004, for the American Association of Retired Persons (AARP) and the Consumers Council of Missouri.

Robert Wagner, 9005 North Chatham Avenue, Kansas City, Missouri 64154, *pro se*.

Lewis R. Mills, Jr., Public Counsel, Office of the Public Counsel, 200 Madison Street, Post Office Box 2230, Jefferson City, Missouri 65102, for the Office of the Public Counsel and the public.

Kevin A. Thompson, Chief Staff Counsel, **Steven Dottheim**, Chief Deputy Staff Counsel, **Nathan Williams**, Deputy Staff Counsel, **Jaime N. Ott,** Assistant Staff Counsel, **Jennifer Hernandez,** Associate Staff Counsel, **Sarah Kliethermes,** Associate Staff Counsel, **Eric Dearmont,** Assistant Staff Counsel, **Annette Slack,** Chief Litigation Counsel, and **Meghan McClowry**, Assistant Staff Counsel, Missouri Public Service Commission, 200 Madison Street, Post Office Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

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

---

[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

---

[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

---

[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

---

[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] ―The 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

---

[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:

---

[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.

The Issues

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.

(~~C~~EP") 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 (~~M~~RA") 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 (~~K~~CC") Staff.[55]

---

[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]

---

[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]

[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]

---

[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]

---

[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

[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

---

[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]

<u>Staff Perspective of Cost Control System</u>

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]

---

[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

---

[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.4th 598, 616 (1982); *see also Re Kansas City Power & Light Co.*, 55 P.U.R.4th 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.4th 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

[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

---

[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]

---

[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]

---

[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

[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]

---

[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 ―the 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]

---

[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

[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, ―SinceAlstom 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

[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,

---

[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]

---

[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

[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]

---

[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]

---

[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:

---

[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 —$50 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

---

[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]

---

[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]

---

[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]

<u>*Construction Resurfacing Project Adjustment*</u>

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]

---

[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.

Conclusions of Law – Iatan

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]

[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]

---

[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

---

[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]

---

[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] ―eflect 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]

[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 —si 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 —theCompany 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]

---

[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

---

[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

[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.

---

[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]

---

[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.

---

[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.

Decision – Crossroads

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.

C. Jeffrey FGD Rebuild Project

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 unreasonable of Westar and GMO not to require PMSI to obtain a performance bond,

[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

---

[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]

---

[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]

---

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]

---

[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]

---

[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

[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]

---

[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]

Decision – Demand-Side Management

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

---

[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.

E. Fuel Switching Program

Should the Commission adopt MGE's fuel switching proposal?

Findings of Fact – Fuel Switching Program

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

---

[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]

---

[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

---

[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

[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

---

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. ―The 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

---

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.

<u>Conclusions of Law – Fuel Switching Program</u>

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

[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.

Decision – Fuel Switching Program

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

[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]

<u>MEUA, MIEC and DOE Witness Gorman</u>

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]

---

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

---

[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]

[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%,

[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]

---

[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]

---

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]

---

[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]

Other Return on Equity Methodologies

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]

---

[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]

---

[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]

---

[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

[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

[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

---

[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

---

[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

---

[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.

[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 (~~"O~~SS") 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

[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

---

[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]

---

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]

---

[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

---

[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]

---

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

---

[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. ―Transaction 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

[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

---

[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]

---

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

---

[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

---

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]

---

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

[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]

---

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

---

[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.

---

[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.

---

[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.

---

[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]

---

[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.

---

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]

---

[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]

---

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]

---

[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.

---

[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

---

[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 ―PAs"). 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 ―CG" 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.

---

[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]

---

[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.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

and

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

REPORT AND ORDER

Issue Date: January 9, 2013

Effective Date: January 9, 2013

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

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

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

and

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

REPORT AND ORDER

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

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

The Commission is authorizing return on equity as follows:

Applicant	*%*
KCPL	9.70
GMO	9.70

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

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

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

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

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

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

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

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

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

[4] Section 386.420.2, RSMo 2000.

Table of Contents

I. Jurisdiction

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

Findings of Fact

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

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

3. Applicants' customers consist of approximately the following.

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

II. Procedural Background

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

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

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

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

---

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

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

[9] Section 393.150, RSMo 2000.

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

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

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

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

a. Test year to determine how much the Applicants need to provide safe and adequate service at just and reasonable rates: 12 months ending September 31, 2011;

b. Update for known and measurable changes to amounts drawn from the test year: through March 31, 2012; and

c. True-up for other significant items relevant to rates: through August 31, 2012.

---

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

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

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

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

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

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

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

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

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

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

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

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

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

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

---

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

[18] Section 393.1075, RSMo Supp. 2012.

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

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

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

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

[23] On July 6, 2012.

III. Settlements

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

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

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

---

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

[25] Sections 536.060, RSMo 2000.

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

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

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

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

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

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

A. Standard for Service

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

---

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

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

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

[32] Section 536.090, RSMo 2000.

[33] Section 393.150.2, RSMo 2000.

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

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

[36] Section 393.130.1, RSMO Supp. 2012.

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

B. Standard for Rates

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

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

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

---

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

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

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

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

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

[42] *Id*.

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

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

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

Those components relate to each other in the following formula:

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

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

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

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

C. Conclusion as to Matters Settled

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

IV. Matters not Addressed in Settlements

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

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

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

---

[45] Section 536.060, RSMo 2000.

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

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

A. KCPL and GMO

The following matters are common to both KCPL and GMO.

i. Policy Matters

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

Findings of Fact

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

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

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

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

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

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

Discussion

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

ii. Return on Equity

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

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

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

---

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

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

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

<u>Findings of Fact</u>

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

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

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

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

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

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

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

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

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

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

For those factors, current conditions are as follows.

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

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

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

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

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

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

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

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

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

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

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

<u>Conclusions of Law</u>

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

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

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

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

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

as follows.

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

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

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

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

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

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

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

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

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

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

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

---

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

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

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

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

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

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

---

described more fully below.

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

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

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

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

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

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

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

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

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

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

ii. Capital Structure

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

Findings of Fact

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

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

iii. Cost of Debt

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

Findings of Fact

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

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

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

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

iv. Transmission Tracker

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

Findings of Fact

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

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

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

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

---

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

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

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

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

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

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

And:

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

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

> Extraordinary items. . . . Those items related to the effects of events and transactions which have occurred during the current period and which are of unusual nature and infrequent occurrence shall be considered extraordinary items. Accordingly, they will be events and transactions of significant effect which are abnormal and significantly different from the ordinary and typical activities of the company, and which would

[55] General Instruction No. 7.

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

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

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

That language examines an event's:

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

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

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

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

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

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

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

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

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

---

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

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

v. Winter, Space Heat, and All-Electric

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

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

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

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

Findings of Fact

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

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

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

and for GMO:

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

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

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

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

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

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

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

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

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

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

Conclusions of Law

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

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

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

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

---

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The results are:

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

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

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

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

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

For GMO, 6% to each of the following:

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

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

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

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

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

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

vi. PURPA

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

Findings of Fact

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

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

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

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

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

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

---

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

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

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

[71] Issued on November 23, 2009.

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

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

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

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

---

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

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

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

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

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

---

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

[74] Section 393.1075.3, RSMo Supp. 2012.

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

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

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

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

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

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

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

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

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

[78] On November 19, 2012.

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

(1) conservation of electric energy,

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) total costs;

(ii) cost-effectiveness;

(iii) improved reliability;

(iv) security;

(v) system performance; and

(vi) societal benefit.

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

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

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

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

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

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

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

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

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

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

Findings of Fact

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

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

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

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

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

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

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

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

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

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

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

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

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

C. GMO Only (ER-2012-0175)

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

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

---

[79] Section 393.135, RSMo 2000.

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

i. Crossroads

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

---

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

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

Findings of Fact

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

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

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

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

Findings of Fact

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

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

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

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

---

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

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

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

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

---

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

[85] 4 CSR 240-20-030.

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

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

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

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

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

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

---

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

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

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

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

Findings of Fact

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

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

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

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

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

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

---

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

ii. Off-System Sales Margins

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

iii. Fuel Adjustment Clause

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

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

For GMO's FAC, the Commission is ordering:

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

---

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

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

Findings of Fact

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

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

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

---

[92] Section 386.266.1, RSMo Supp. 2012.

[93] Section 386.266.1, RSMo Supp. 2012.

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

Among those incentives is the sharing percentage.

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

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

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

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

---

[94] Section 386.266.1, RSMo Supp. 2012.

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

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

Findings of Fact

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

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

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

Discussion, Conclusions of Law, and Ruling

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

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

---

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

[97] Section 386.266.1, RSMo Supp. 2012.

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

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

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

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

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

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

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

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

V. Compliance Tariffs

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

THE COMMISSION ORDERS THAT:

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

[98] Section 386.490.2, RSMo 2000.

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

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

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

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

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

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

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

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

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

5. No later than January 16, 2013:

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

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

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

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

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

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

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

BY THE COMMISSION

(S E A L)

Shelley Brueggemann

Shelley Brueggemann
Acting Secretary

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

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

Appendix A: Appearances

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

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

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

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

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

Senior Regulatory Law Judge: Daniel Jordan.

Appendix B: Briefs and Statements after Evidentiary Hearing

i. Initial Briefs

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

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

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

ii. Reply Briefs

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

Appendix C: USoA Accounts for Other Regulatory Assets and Liabilities

182.3 Other regulatory assets.

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

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

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

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

18 C.F.R. § 201

254 Other regulatory liabilities.

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

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

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

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

18 C.F.R. § 201

Appendix D: Additional FAC Reporting

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

- Within 30 days of any change in a GMO hedging policy, GMO provides a copy of the changed hedging policy for Staff to retain;
- GMO provides a copy of GMO's internal policy for participating in the SPP, including any GMO sales or purchases from that market that are in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain; and
- If GMO revises any internal policy for participating in the SPP, within 30 days of that revision, GMO provides a copy of the revised policy with the revisions identified for Staff to retain.

Appendix E: Tariff Sheets Rejected

The tariff sheets rejected are:

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

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

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

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

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

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

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